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Development Document For Effluent Limitations Guidelines And New Source Performance Standards For The Offshore Subcategory Of The Oil And Gas Extraction Point Source Category

Final

DEVELOPMENT DOCUMENT

for

FINAL EFFLUENT LIMITATIONS GUIDELINES

and

NEW SOURCE PERFORMANCE STANDARDS

for the

OFFSHORE SUBCATEGORY

of the

OIL AND GAS EXTRACTION POINT SOURCE CATEGORY

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TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

LIST OF FIGURES

LIST OF TABLES

LIST OF TABLES (Continued)

LIST OF TABLES (Continued)

LIST OF TABLES (Continued)

LIST OF TABLES (Continued)

LIST OF TABLES (Continued)

SECTION I

INTRODUCTION

1.0 LEGAL AUTHORITY

The Environmental Protection Agency (EPA) is establishing these final Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category under the authority of Sections 301, 304 (b), (c), and (e), 306, 307, 308, and 501 of the Clean Water Act (CWA) (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), 1315, 1317, and 1361; 86 Stat. 816, Pub. L. 92-500; 91 Stat. 1567, Pub. L. 95-217; and 101 Stat. 7, Pub. L. 100-4).

1.1 BACKGROUND

1.1.1 Clean Water Act

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

1. Best Practicable Control Technology Currently Available (BPT)

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

In establishing BPT effluent limitations guidelines, EPA considers the following criteria: (1) total cost of achieving effluent reductions in relation to the effluent reduction benefits, (2) the age of equipment and facilities involved, (3) the processes employed, (4) the process changes required, (5) the engineering aspects of the control technologies, (6) the non-water quality environmental impacts (including energy requirements), and (7) other factors as the EPA Administrator deems appropriate (Section 304(b)(1)(B) of the CWA). EPA considers the category- or subcategory-wide cost of applying the technology in relation to the effluent reduction benefits. Where existing performance is uniformly inadequate, BPT may be transferred from a different subcategory or category.

2. *Best Available Technology Economically Achievable (BAT)*

In general, BAT effluent limitations guidelines represent the best existing economically achievable performance of plants in the industrial subcategory or category. The CWA establishes BAT as a principal national means of controlling the direct discharge of priority pollutants and nonconventional pollutants to navigable waters. The factors considered in assessing BAT include the following: (1) the age of the equipment and facilities involved, (2) the processes employed, (3) the engineering aspects of the control technologies, (4) potential process changes, (5) the costs and economic impact of achieving such effluent reduction, (6) non-water quality environmental impacts (including energy requirements, Section 304(b)(2)(B), and (7) other factors as the EPA Administrator deems appropriate. EPA retains considerable discretion in assigning the weight to be accorded these factors. As with BPT, where existing performance is uniformly inadequate, BAT may be transferred from a different subcategory or category. BAT may include process changes or internal controls, even when these technologies are not common industry practice.

3. *Best Conventional Pollutant Control Technology (BCT)*

The 1977 Amendments added Section 301(b)(2)(E) to the CWA establishing "best conventional pollutant control technology" (BCT) for the discharge of conventional pollutants from existing industrial point sources. Section 304(a)(4) designated the following as conventional pollutants: biochemical oxygen demand (BOD_5), total suspended solids (TSS), fecal coliform, pH, and any additional pollutants defined by the Administrator as conventional. The Administrator designated oil and grease as an additional conventional pollutant on July 30, 1979 (44 *FR* 44501).

BCT is not an additional limitation, but replaces BAT for the control of conventional pollutants. Where the BCT limitations differ from the BAT limitations, the more stringent of the limitations apply. In addition to other factors specified in section 304(b)(4)(B), the CWA requires that BCT effluent limitations guidelines be established in light of a two-part "cost-reasonableness" test (*American Paper*

Institute v. *EPA*, 660 F.2d 954 (4th Cir. 1981)). The methodology for establishing BCT effluent limitations guidelines became effective on August 22, 1986 (51 *FR* 24974, July 8, 1986).

4. New Source Performance Standards (NSPS)

NSPS are based on the performance of 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. As a result, NSPS should represent the most stringent numerical values attainable through the application of best available demonstrated control technology for all pollutants (i.e., conventional, nonconventional, and priority pollutants). In establishing NSPS, EPA is directed to take into consideration the cost of achieving the effluent reduction and any non-water quality environmental impacts and energy requirements.

1.1.2 Section 304(m) Requirements and Litigation

Section 304(m) of the CWA (33 U.S.C. 1314(m)), added by the Water Quality Act of 1987, requires EPA to establish schedules for (1) reviewing and revising existing effluent limitations guidelines and standards (effluent guidelines), and (2) promulgating new effluent guidelines. On September 8, 1992, EPA published an Effluent Guidelines Plan (57 *FR* 41000), in which schedules were established for developing new and revised effluent guidelines for several industry subcategories and categories. One of the industries for which EPA established a schedule was the offshore subcategory of the oil and gas extraction point source category (offshore subcategory). Although referenced in the Effluent Guidelines Plan under Section 304(m), the offshore guidelines are not subject to the Consent Decree that EPA entered into in the 304(m) litigation.

1.1.3 Pollution Prevention Act

In the Pollution Prevention Act of 1990 (42 U.S.C. 13101 et seq., Pub.l. 101-508, November 5, 1990), Congress declared pollution prevention the national policy of the United States. This act declares that pollution should be prevented or reduced whenever feasible; pollution that cannot be prevented should be recycled or reused in an environmentally safe manner wherever feasible; pollution that cannot be recycled should be treated; and disposal or release into the environment should be chosen only as a last resort.

1.1.4 Prior Regulation and Litigation for the Offshore Subcategory

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. EPA promulgated final BPT regulations on April 13, 1979 (44 *FR* 22069), but deferred action on the BAT and NSPS regulations. Table I-1 presents the 1979 BPT limitations.

TABLE I-1

OFFSHORE SUBCATEGORY BPT EFFLUENT LIMITATIONS*

Waste Stream	Parameter	BPT Effluent Limitation
Produced Water	Oil and Grease	72 mg/l Daily Maximum 48 mg/l 30-Day Average
Drilling Muds	Free Oil*	No Discharge
Drilling Fluids	Free Oil*	No Discharge
Well Treatment Fluids	Free Oil*	No Discharge
Deck Drainage	Free Oil*	No Discharge
Sanitary-M10	Residual Chlorine	1 mg/l (minimum)
Sanitary-M9IM	Floating Solids	No Discharge

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

On August 26, 1985 (50 *FR* 34592) EPA proposed BAT and BCT effluent limitations guidelines, and new source performance standards for the offshore subcategory. This 1985 proposal also included an amendment to the BPT definition of "no discharge of free oil." The waste streams covered by the 1985 proposal were drilling fluids, drill cuttings, produced water, deck drainage, well treatment fluids, produced sand, and sanitary and domestic wastes. Table I-2 provides a summary of the preferred options as proposed in 1985.

On October 21, 1988, EPA issued a Notice of Data Availability (53 *FR* 41356) concerning the development of NSPS, BAT, and BCT regulations for the drilling fluids and drill cuttings waste streams. This 1988 notice presented substantial additional and revised technical, cost, economic, and environmental effects information which EPA collected after publication of the 1985 proposal.

EPA presented new information regarding the diesel oil prohibition and the toxicity limitation, and new compliance costing and economic analysis results based on new profile data and treatment and control option development. The new control technologies discussed were based on thermal distillation, thermal oxidation, and solvent extraction. Performance data for these technologies were also included. In addition, EPA proposed requirements for limitations on metals content in the stock barite based on the use of existing barite supplies, or alternatively in the drilling fluids (whole fluid basis) at point of discharge, for comment.

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

On November 26, 1990, EPA 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. On March 13, 1991 (56 *FR* 10664), EPA published a second notice proposing BAT, BCT, and NSPS limitations and standards for the offshore subcategory. The regulatory options presented were the same as those proposed on November 26, 1990 with the exception of the deletion of a requirement under NSPS which prohibited the discharge of visible foam from the sanitary waste stream (this requirement had been inadvertently included in the November 1990 proposal).

The 1990 and 1991 proposals did not supersede the 1985 proposal or the information included in the 1988 and 1989 notices. Rather, they revised the 1985 proposal in certain areas. The revisions were based on new data and information acquired by EPA since the 1985 proposal regarding waste characterization, treatment technologies, industrial practices, industry profiles, analytical methods,

TABLE I-2

1985 PROPOSED EFFLUENT LIMITATIONS - PREFERRED OPTIONS

Stream	Pollutant Parameter	Effluent Limitations		
		BCT	BAT	NSPS
Produced Water	Oil & Grease	No discharge if the maximum for any one day exceeds 72 mg/l, and the average of daily values for 30 consecutive days exceeds 48 mg/l (BPT)	[Reserved]	No discharge if the maximum of 59 mg/l is exceeded in any one day (based on improved operating performance of gas flotation)
Drilling Fluids	Free Oil	No discharge	No discharge	No discharge
	Oil-Based Fluid		No discharge	No discharge
	Diesel Oil		No discharge in detectable amounts	No discharge in detectable amounts
	Toxicity		Minimum 96-hr LC50 of the diluted suspended particulate phase (SPP) of the drilling fluid shall be 3.0% by volume	Minimum 96-hr LC50 of the diluted suspended particulate phase (SPP) of the drilling fluid shall be 3.0% by volume
	Cadmium		1 mg/kg dry weight maximum in the whole drilling fluid	1 mg/kg dry weight maximum in the whole drilling fluid
	Mercury		1 mg/kg dry weight maximum in the whole drilling fluid	1 mg/kg dry weight maximum in the whole drilling fluid
Drill Cuttings	Free Oil	No discharge	No discharge	No discharge
	Oil-Based Fluid		No discharge	No discharge
	Diesel Oil		No discharge in detectable amounts	No discharge in detectable amounts
Well Treatment Fluids	Free Oil	No discharge	No discharge	No discharge
Produced Sand	Free Oil	No discharge	No discharge	No discharge
Deck Drainage	Free Oil	No discharge	No discharge	No discharge
Sanitary Waste				
Sanitary M10	Residual Chlorine	No discharge if minimum of 1 mg/l is not maintained	None	No discharge if minimum 1 mg/l is not maintained
Sanitary M91M	Floating Solids	No discharge	None	No discharge
Domestic Waste	Floating Solids	No discharge	None	No discharge

environmental effects, costs, and economic impacts. Some of this new *information regarding drilling* wastes had been published in a Notice of Data Availability (53 *FR* 41356, Oct. 21, 1988). This new information led EPA to develop additional regulatory options to those proposed in 1985. Table I-3 presents a summary of the preferred options as proposed in 1991.

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

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

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

Table I-4 presents a summary of the *Federal Register* Notices that pertain to this rulemaking.

TABLE I-3A

1991 PROPOSED EFFLUENT LIMITATIONS - PREFERRED OPTIONS

Stream	Pollutant Parameter	Effluent Limitations		
		BCT	BAT	NSPS
Produced Water				
A) All Structures	Oil & Grease	No discharge if the maximum for any one day exceeds 72 mg/l, and the average of daily values for 30 consecutive days exceeds 48 mg/l (BPT)		
B) Facilities located within 4 miles from shore	Oil & Grease		No discharge if the maximum for any one day exceeds 13 mg/l, and the average daily values for 30 consecutive days exceeds 7 mg/l (based on membrane filtration)	No discharge if the maximum for any one day exceeds 13 mg/l, and the average daily values for 30 consecutive days exceeds 7 mg/l (based on membrane filtration)
C) Facilities located beyond 4 miles from shore	Oil & Grease		No discharge if the maximum for any one day exceeds 72 mg/l, and the average daily values for 30 consecutive days exceeds 48 mg/l (BPT)	No discharge if the maximum for any one day exceeds 72 mg/l, and the average daily values for 30 consecutive days exceeds 48 mg/l (BPT)
Drilling Fluids and Drill Cuttings				
A) Facilities located within 4 miles from shore		No discharge(1)	No discharge(1)	No discharge(1)
B) Facilities located beyond 4 miles from shore	Free Oil	No discharge(2)	No discharge(2)	No discharge(2)
	Diesel Oil		No discharge in detectable amounts	No discharge in detectable amounts
	Toxicity		Minimum 96-hr LC50 of the diluted suspended particulate phase (SPP) of the drilling fluid shall be 3% by volume	Minimum 96-hr LC50 of the diluted suspended particulate phase (SPP) of the drilling fluid shall be 3% by volume
	Cadmium		1 mg/kg dry weight maximum in the whole drilling fluid	1 mg/kg dry weight maximum in the whole drilling fluid
	Mercury		1 mg/kg dry weight maximum in the whole drilling fluid	1 mg/kg dry weight maximum in the whole drilling fluid

(1) All Alaskan facilities are subject to the drilling fluids and drill cuttings limitations for facilities located beyond 4 miles from shore.
(2) Based on the Static Sheen Test

TABLE I-3B

1991 PROPOSED EFFLUENT LIMITATIONS - PREFERRED OPTIONS

Stream	Pollutant Parameter	Effluent Limitations		
		BCT	BAT	NSPS
Well Treatment, Completion and Workover Fluids	Free Oil	No discharge(1)	No discharge of fluids slug plus 100-barrel buffer on either side	No discharge of fluids slug plus 100-barrel buffer on either side
Produced Sand	Free Oil	No discharge(1)	No discharge	No discharge
Deck drainage				
A) All Structures	Free Oil	No discharge(1)		
B) During Production				
1. Facilities located within 4 miles from shore	Oil & Grease		No discharge if the maximum for any one day exceeds 13 mg/l, and the average daily values for 30 consecutive days exceeds 7 mg/l (based on commingling with produced water treatment)	No discharge if the maximum for any one day exceeds 13 mg/l, and the average daily values for 30 consecutive days exceeds 7 mg/l (based on commingling with produced water treatment)
2. Facilities located beyond 4 miles from shore			No discharge if the maximum for any one day exceeds 72 mg/l, and the average daily values for 30 consecutive days exceeds 48 mg/l (based on commingling with produced water treatment)	No discharge if the maximum for any one day exceeds 72 mg/l, and the average daily values for 30 consecutive days exceeds 48 mg/l (based on commingling with produced water treatment)
C) During Drilling	Oil & GreaseFree Oil		No discharge(1)	No discharge(1)
Sanitary Waste				
Sanitary M10	Residual Chlorine	No discharge if minimum of 1 mg/l is not maintained	None	No discharge if minimum of 1 mg/l is not maintained
Sanitary M91M	Floating Solids	No discharge	None	No discharge
Domestic Waste	Floating Solids	No discharge	None	No discharge
	Foam		None	No discharge

(1) Based on Static Sheen Test

TABLE I-4

SUMMARY OF OFFSHORE OIL AND GAS SUBCATEGORY
FEDERAL REGISTER NOTICES

Level of Control	Action	Date
BPT	Interim Final	Sept. 15, 1975 (40 FR 42543)
BAT/NSPS	Proposal	Sept. 15, 1975 (40 FR 42572)
BPT/BAT/NSPS	Final (BPT) Reserved (BAT/NSPS)	April 13, 1979 (44 FR 22069)
NSPS	Withdraw Proposal	August 22, 1980 (45 FR 56115)
BAT	Withdraw Proposal	March 19, 1981 (46 FR 17567)
BAT/BCT/NSPS	Proposal	August 26, 1985 (50 FR 34592)
BAT/BCT/NSPS	Notice of Data Availability (Drilling Muds & Cuttings)	October 21, 1988 (53 FR 41356)
BAT/BCT/NSPS	Correction to Notice of Data Availability	January 9, 1989 (54 FR 634)
BAT/BCT/NSPS	Initial Proposal Reproposal	November 26, 1990 (55 FR 49094)
BAT/BCT/NSPS	Proposal	March 13, 1991 (56 FR 10664)

SECTION II

SUMMARY OF THE FINAL REGULATIONS

1.0 INTRODUCTION

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 435, Subpart A. The existing effluent limitations guidelines, which were issued on April 13, 1979 (44 *FR* 22069), are based on the achievement of BPT.

1.1 BPT LIMITATIONS

In general, BPT represents the average of the best existing performances of well-known technologies and techniques for the control of pollutants. BPT for the offshore subcategory accomplishes the following: (1) limits the discharge of oil and grease in produced water to a daily maximum of 72 mg/l and a monthly average of 48 mg/l; (2) prohibits the discharge of free oil in deck drainage, drilling fluids, drill cuttings, and well treatment fluids; (3) requires a minimum residual chlorine content of 1 mg/l in sanitary discharges; and (4) prohibits the discharge of floating solids in sanitary and domestic wastes. BPT effluent limitations are not being changed by this rule. A summary of the BPT effluent limitations is presented in Table I-1 in Section I.1.1.4.

1.2 SUMMARY OF THE FINAL RULE

This rule establishes regulations based on BAT that will result in reasonable progress toward the goal of the CWA to eliminate the discharge of all pollutants. At a minimum, BAT represents the best economically achievable performance in the industrial category or subcategory. This rule also establishes requirements based on BCT. In addition, this rule establishes NSPS based on the best demonstrated control technology.

This section summarizes the BCT, BAT, and NSPS limitations for the final rule by classifying the regulated waste stream as either a major waste stream or a miscellaneous waste stream. Produced water, drilling fluids, and drill cuttings are classified as major waste streams. Deck drainage, produced sand, well treatment, workover, and completion fluids, sanitary wastes, and domestic wastes are classified as miscellaneous wastes.

1.2.1 BAT and NSPS for Major Waste Streams

Under this rule, EPA is promulgating the following NSPS and BAT effluent limitations guidelines for the offshore subcategory. This rule limits the discharge of oil and grease in produced water to a daily maximum of 42 mg/l and a monthly average of 29 mg/l based on improved operating performance of gas flotation technology. For this rulemaking, oil and grease is being limited as an indicator for toxic and nonconventional pollutants. Furthermore, EPA is prohibiting the discharge of drilling fluids and drill cuttings from wells located within 3 nautical miles from shore (the inner boundary of territorial seas). For wells located beyond 3 nautical miles from shore, this rule establishes BAT and NSPS limitations for discharges of drilling fluids and drill cuttings of toxicity equal to or greater than 30,000 ppm (three percent by volume) in the suspended particulate phase (SPP), cadmium and mercury in stock barite at 3 mg/kg and 1 mg/kg, respectively, on a dry weight basis. This rule also prohibits the discharge of diesel oil and prohibits the discharge of free oil as determined by the static sheen test. All wells drilled off the Alaskan coast are excluded from the zero discharge limitation; instead, all discharges of drilling fluids and drill cuttings must comply with the limitations on toxicity, cadmium, and mercury, and the prohibitions on the discharge of free oil and diesel oil.

1.2.2 BAT AND NSPS for Miscellaneous Waste Streams

EPA is promulgating BAT and NSPS limitations equal to BPT limitations for deck drainage. These limitations prohibit the discharge of free oil as determined by the visual sheen test. Discharges of produced sand are prohibited under the BAT and NSPS effluent limitation of this rule. For treatment, completion, and workover fluids, this rule establishes BAT and NSPS limits on the discharge of oil and grease to 29 mg/l monthly average and 42 mg/l daily maximum (equal to those of produced water). EPA is promulgating limitations on domestic waste prohibiting the discharge of foam (BAT and NSPS) and floating solids (BCT and NSPS), as well as incorporating MARPOL (International Convention for Prevention of Pollution from Ships) limitations which prohibit all discharges of plastics and garbage, ban discharge of victual waste within 12 nautical miles of nearest land, and require that victual waste discharged more than 12 nautical miles from nearest land must be comminuted or ground (BCT and NSPS). For sanitary wastes, EPA is promulgating BCT and NSPS limitations equal to BPT limitations. These limitations prohibit the discharge of floating solids from facilities with 9 or fewer personnel and require a minimum chlorine content of 1 mg/l for facilities with 10 or more personnel. EPA is not establishing BAT for sanitary wastes because there have been no toxic or nonconventional pollutants of concern identified in these wastes.

1.2.3 BCT for Major and Miscellaneous Waste Streams

BCT for produced water is equal to current BPT limitations. EPA is establishing BCT limitations for drilling fluids and drill cuttings equal to the zero discharge portion of BAT for distances of 3 nautical miles or less from shore, and no discharge of free oil, as determined by the static sheen test, for wells drilled at distances greater than 3 nautical miles from shore. Discharges of produced sand are prohibited under BCT. BCT limitations for well treatment, completion, and workover fluids prohibit the discharge of free oil as determined by the static sheen test. EPA is establishing BCT limits on deck drainage that prohibit discharge of free oil, as determined by the visual sheen test.

1.2.4 BCT, BAT and NSPS Summary Tables for the Final Rule

Table II-1 presents a summary of the BCT limitations for the final rule; Table II-2 presents a summary of the BAT limitations for the final rule; and Table II-3 presents a summary of the NSPS limitations for the final rule.

TABLE II-1

BCT EFFLUENT LIMITATIONS

Stream	Pollutant Parameter	BCT Effluent Limitations
Produced Water (all facilities)	Oil & Grease	No discharge if the maximum for any one day exceeds 72 mg/l and the monthly average exceeds 48 mg/l
Drilling Fluids and Drill Cuttings		
A) Facilities located within 3 miles from shore.		No discharge(1)
B) Facilities located beyond 3 miles from shore.	Free Oil	No discharge(2)
Well Treatment, Completion, and Workover Fluids	Free Oil	No discharge(2)
Produced Sand		No discharge
Deck Drainage	Free Oil	No discharge(3)
Sanitary Waste		
Sanitary M10	Residual Chlorine	No discharge if minimum of 1 mg/l is not maintained
Sanitary M91M	Floating Solids	No discharge
Domestic Waste	Floating Solids and MARPOL Limits	No discharge of Floating Solids

(1) Alaskan facilities are exempt from "No discharge" limitation. They are required to comply with the same discharge limitations as facilities located beyond 3 miles from shore.
(2) As determined by the Static Sheen Test
(3) As determined by the Visual Sheen Test

TABLE II-2

BAT EFFLUENT LIMITATIONS

Stream	Pollutant Parameter	BAT Effluent Limitations
Produced Water (all facilities)	Oil & Grease	No discharge if the maximum for any one day exceeds 42 mg/l, and the monthly average exceeds 29 mg/l
Drilling Fluids and Drill Cuttings		
A) Facilities located within 3 miles from shore.		No discharge[(1)]
B Facilities located beyond 3 miles from shore.	Toxicity	No discharge if minimum 96-hour LC50 of SPP is not at 3% by volume
	Free Oil	No discharge[(2)]
	Diesel Oil	No discharge
	Mercury	1 mg/kg dry weight maximum in stock barite
	Cadmium	3 mg/kg dry weight maximum in stock barite
Well Treatment, Completion, and Workover Fluids	Oil & Grease	Same as produced water
Produced Sand		No discharge
Deck Drainage	Free Oil	No discharge[(3)]
Sanitary Waste		
Sanitary M10	None	-
Sanitary M91M	None	-
Domestic Waste	Foam	No discharge

(1) Alaskan facilities are exempt from "No discharge" limitation. They are required to comply with the same discharge limitations as facilities located beyond 3 miles from shore.
(2) As determined by the Static Sheen Test
(3) As determined by the Visual Sheen Test

TABLE II-3

NSPS EFFLUENT LIMITATIONS

Stream	Pollutant Parameter	NSPS Effluent Limitations
Produced Water (all facilities)	Oil & Grease	No discharge if the maximum for any one day exceeds 42 mg/l, and the monthly average exceeds 29 mg/l
Drilling Fluids and Drill Cuttings		
A) Facilities located within 3 miles from shore.		No discharge[1]
B) Facilities located beyond 3 miles from shore.		
	Toxicity	No discharge if minimum 96-hour LC50 of SPP is not at 3% by volume
	Free Oil	No discharge[2]
	Diesel Oil	No discharge
	Mercury	1 mg/kg dry weight maximum in stock barite
	Cadmium	3 mg/kg dry weight maximum in stock barite
Well Treatment, Completion, and Workover Fluids	Oil & Grease	Same as produced water
Produced Sand		No discharge
Deck Drainage	Free Oil	No discharge[3]
Sanitary Waste		
Sanitary M10	Residual Chlorine	No discharge if minimum of 1 mg/l is not maintained
Sanitary M91M	Floating Solids	No discharge
Domestic Waste	Floating Solids & MARPOL Limits	No discharge of floating solids
	Foam	No discharge

(1) Alaskan facilities are exempt from "No discharge" limitation. They are required to comply with the same discharge limitations as facilities located beyond 3 miles from shore.
(2) As determined by the Static Sheen Test
(3) As determined by the Visual Sheen Test

SECTION III

INDUSTRY SUBCATEGORIZATION

1.0 INTRODUCTION

This section describes the offshore subcategory by (1) regulatory definition, (2) geographic locations, and (3) classification of the major, miscellaneous, and minor waste streams.

2.0 REGULATORY DEFINITION

The offshore subcategory of the oil and gas extraction point source category, as defined in 40 CFR 435.10, is comprised of those structures involved in exploration, development, and production operations seaward of the inner boundary of the territorial seas (shoreline). This rulemaking covers offshore activities included in the following SICs: 1311-Crude Petroleum and Natural Gas, 1381-Drilling Oil and Gas Wells, 1382-Oil and Gas Field Exploration Services, and 1389-Oil and Gas Field Services, not classified elsewhere.

Structures are classified as "offshore" if they are located in waters 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 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."

In some areas, the inner boundary of the territorial seas is clearly established and shown on maps. For example, the Texas General Land Office (Survey Division) has 7.5 minute quadrangle maps available for the entire coastline of Texas which clearly show the inner boundary of the territorial seas. Additionally, the Louisiana State Minerals Board, Civil and Engineering Division, has maps available for the Louisiana coastline showing the inner boundary of the territorial seas. In general, for Louisiana the inner boundary consists of the coastline or the seaward edge of the outermost barrier islands where there are bays, inlets, and bayous. The inner boundary for California extends from the mainland coast or the seaward edge of all offshore islands. In Alaska, the inner boundary baseline is not clearly established. As part of the permitting process for discharges in the territorial seas, the waters of the contiguous zone, and the oceans, Section 403(c) of the CWA sets out criteria requiring a determination of whether or not the discharge will cause degradation of these waters. The State Department is consulted to make site-specific determinations when it is questionable whether or not the discharge is beyond the baseline (Section 403(c)).

2.1 New Source Definition

The definition of "new source" as it applies to the Offshore Guidelines was discussed at length in EPA's 1985 proposal, 50 *FR* 34617-34619, Aug. 26, 1985. As discussed in that proposal, provisions in the NPDES regulations define new source (40 CFR 122.2) and establish criteria for a new source determination (40 CFR 122.29(b)). In 1985, EPA proposed special definitions which are consistent with 40 CFR 122.29 and which provide that 40 CFR 122.2 and 122.29(b) shall apply "except as otherwise provided in an applicable new source performance standard." (See 49 *FR* 38046, Sept. 26, 1984.)

The Offshore Guidelines apply to all mobile and fixed drilling (exploratory and development) and production operations. In 1985, EPA addressed the question of which of these facilities are new sources and which are existing sources under these guidelines.

As discussed in 1985, Section 306(a)(2) of the Act defines "new source" to mean "any source, the construction of which is commenced after publication of the proposed NSPS if such standards are promulgated consistent with Section 306." The CWA defines "source" to mean any "facility . . . from which there is or may be a discharge of pollutants" and "construction" to mean "any placement, assembly, or installation of facilities or equipment . . . at the premises where such equipment will be used."

The regulations implementing this provision state, in part:

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

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

(b) After proposal of standards of performance in accordance with section 306 of the Act which are applicable to such source, but only if the standards are promulgated in accordance with section 306 within 120 days of their proposal." 40 CFR § 122.2.

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

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

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

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

(ii) Entered into a binding contractual obligation for the purchase of facilities or equipment which are intended to be used in its operation within a reasonable time. Options to purchase or contracts which can be terminated or modified without substantial loss, and contracts for feasibility engineering and design studies do not constitute a contractual obligation under the paragraph." 40 CFR § 122.29(b)(4) (emphasis added).

In 1985, EPA proposed to define, for purposes of the Offshore Guidelines, "significant site preparation work" as "the process of clearing and preparing an area of the ocean floor for purposes of constructing or placing a development or production facility on or over the site." (emphasis added). Thus, development and production wells would be new sources under the Offshore Guidelines. Further, with regard to 40 CFR 122.29(b)(4)(ii), EPA stated that although it was not "proposing a special definition of this provision believing it should appropriately be a decision for the permit writer," EPA suggested that the definition of new source include development or production sites even if the discharger entered into a contract for purchase of facilities or equipment prior to publication, if no specific site was specified in the contract. Conversely, EPA suggested that the definition of new source exclude development or production sites if the discharger entered into a contract prior to publication and a specific site was specified in the contract.

As a consequence of the proposed definition of "significant site preparation work," if "clearing or preparation of an area for development or production has occurred at a site prior to the publication of the NSPS, then subsequent development and production activities at the site would not be considered a new source" (50 *FR* 34618). Also, exploration activities at a site would not be considered significant site preparation work, and therefore exploratory wells would not be new sources (50 *FR* 34618). The purposes of these distinctions were to "grandfather" as an existing source, any source if "significant site preparation work . . . evidencing an intent to establish full scale operations at a site, had been performed prior to NSPS becoming effective" (50 *FR* 34618). At the same time, if only exploratory drilling had occurred prior to NSPS becoming effective, then subsequent drilling and production wells would be considered to be new sources.

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

As a consequence of these distinctions, exploratory facilities would always be existing sources. Production and development facilities where significant site preparation has occurred prior to the effective date of the Offshore Guidelines would also be existing sources. These same production and development facilities, however, would become "new sources" under the proposed regulatory definition if they moved to a new water area to commence production or development activities. The proposed definition, however, presents a problem because even though these facilities would be "new sources" subject to NSPS, they could not be covered by an NPDES permit in the period immediately following the issuance of these regulations. This is because no existing general or individual permits could have included NSPS until NSPS were promulgated. To resolve this problem, the final rule temporarily excludes from the definition of "new source" those facilities that as of the effective date of the Offshore Guidelines are subject to an existing general permit pending EPA's issuance of a new source NPDES general permit. EPA believes this approach is reasonable because when Congress enacted Section 306 of the CWA it did not specifically address mobile activities of the sort common in this industry, as distinguished from activities at stationary facilities on land that had not yet been constructed prior to the effective date of applicable NSPS. Moreover, EPA believes that Congress did not intend that the promulgation of NSPS would result in stopping all oil and gas activities which would have been authorized under existing NPDES permits as soon as the NSPS are promulgated. Now that NSPS are promulgated, EPA intends to apply them to appropriate facilities (i.e., those where there is significant site preparation work for development or production after promulgation of NSPS) within the Offshore Subcategory. EPA intends to issue as final, after opportunity for notice and comment, new source NPDES permits as soon as possible.

2.2 GEOGRAPHICAL LOCATIONS OF THE OFFSHORE INDUSTRY

Offshore exploration, development, and production occurs in areas that are offered for development by Federal or State governments on a leased basis. These areas are known as tracts. The standard Federal offshore leased tract is 5,760 acres or 9 square miles. The Minerals Management Service (MM) is the bureau within the U.S. Department of Interior (DOI) that is responsible for administering the minerals leasing program for the Federal Outer Continental Shelf (OCS). The Federal OCS consists of all areas seaward of the 3 mile boundary except for offshore Texas and Florida which is 3 leagues. The Federal OCS is divided into 26 planning areas to allow for individual consideration for areas having differences in resource potential, environmental concerns, and degree of previous development. Figure III-1 presents a map of the Federal offshore regions. On June 26, 1990, the President of the United States directed the Secretary of Interior to cancel three leasing offerings offshore California (parts of the northern, central, and southern California planning areas), one tract offshore southwestern Florida in the Gulf of Mexico, tracts in the Georges Bank area off New England, and all tracts off the coast of Washington and Oregon[1]. The lease cancellations exclude the above-mentioned Federal OCS planning areas, except tracts located in the Santa Maria Basin and Santa Barbara Channel, from consideration for any lease sale until after the year 2000. Tracts within the Santa Maria Basin and Santa Barbara Channel will be available for leasing after January 1, 1996. These lease cancellations are hereafter referred to as the "presidential moratoria on leasing."

Each State runs its own leasing program and there is no coordination between the States and the Federal MMS in the leasing process. All States except Texas and Florida (the Gulf of Mexico side only) were granted jurisdiction over offshore lands to a distance of 3 nautical miles from their coasts by the Submerged Lands Act (43 U.S.C 1301, et seq.). Texas and Florida (the Gulf of Mexico side only) have jurisdiction to 3 marine leagues (approximately 10.35 statute miles).

2.3 MAJOR WASTES STREAMS

The major waste streams from drilling and production operations are those streams with the greatest volumes and amounts of pollutants. The major waste streams are drilling fluids and drill cuttings from drilling operations and produced water from production operations. The following sections present the regulatory definition for each of these waste streams.

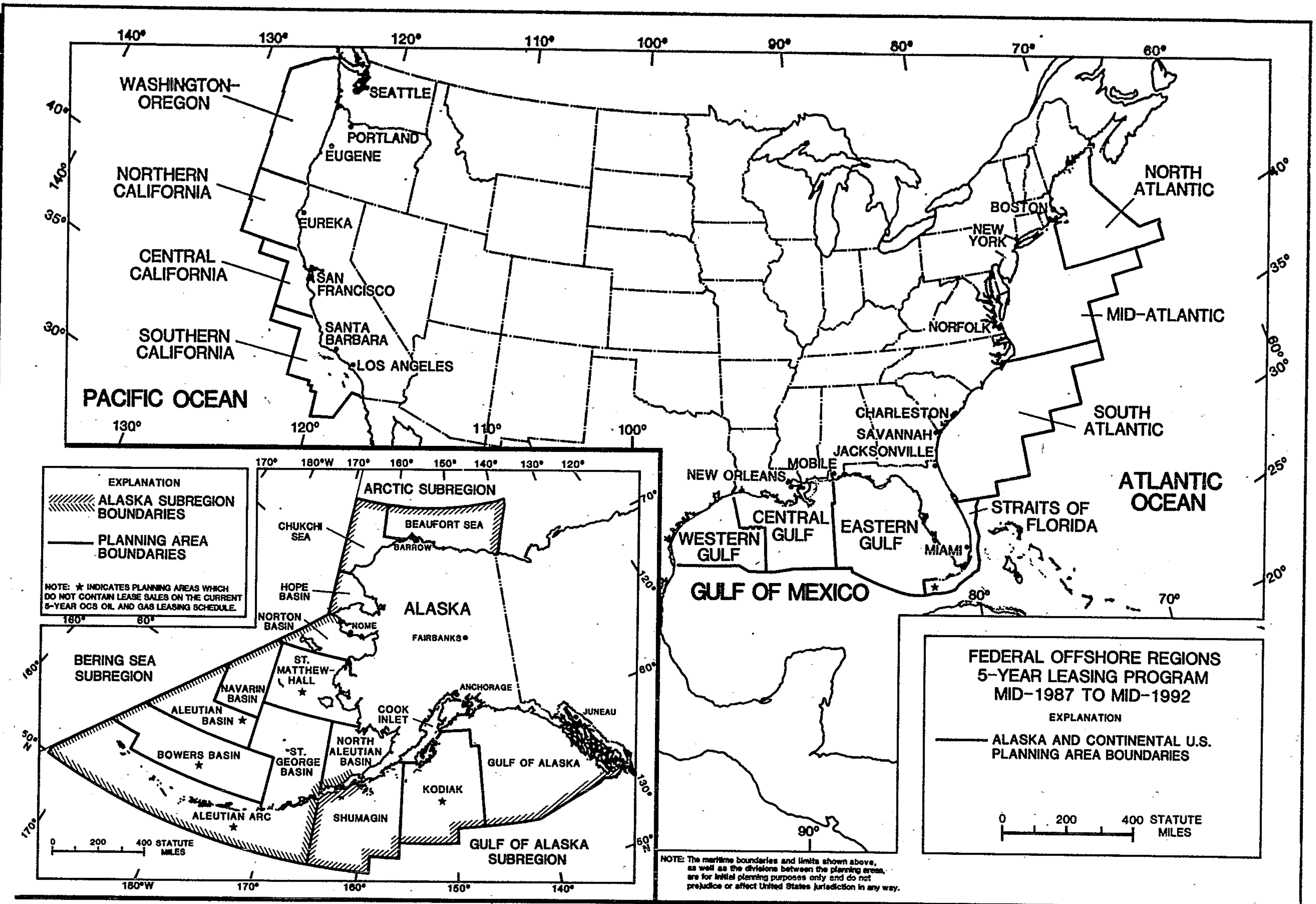

Figure III-1
Federal Outer Continental Shelf Region[2]

2.3.1 Drilling Fluid

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

2.3.2 Drill Cuttings

The term "drill cuttings" refers to the particles generated by drilling into subsurface geologic formations and carried to the surface with the drilling fluid.

2.3.3 Produced Water

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

2.4 MISCELLANEOUS WASTES

Miscellaneous wastes from drilling and production operations are those wastes generated which are relatively small in volume and pollutant levels, yet significant enough to be of regulatory concern. The miscellaneous wastes generated from drilling and production operations are: produced sand, well treatment fluids, well completion fluids, workover fluids, deck drainage, and domestic and sanitary waste. The following sections present the regulatory definition for each of these wastes.

2.4.1 Produced Sand

The term "produced sand" refers to slurried particles used in hydraulic fracturing, the accumulated formation sands and scale 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.

2.4.2 Well Treatment Fluids

The term "well treatment" fluids refers to any fluid used to restore or improve productivity by chemically or physically altering hydrocarbon-bearing strata after a well has been drilled.

2.4.3 Well Completion Fluids

The term "well completion fluids" means 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.

2.4.4 Workover Fluids

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.

2.4.5 Deck Drainage

The term "deck drainage" refers to any waste resulting from deck washing spillage, rain water, and runoff from gutters and drains including drip pans and work areas within facilities subject to this subpart.

2.4.6 Domestic Waste

The term "domestic waste" refers to materials discharged from sinks, showers, laundries, safety showers, eyewash stations, and galleys located within facilities subject to this subpart.

2.4.7 Sanitary Waste

The term "sanitary waste" refers to human body waste discharged from toilets and urinals located within facilities subject to this subpart.

2.5 MINOR WASTES

In addition to those specific wastes for which effluent limitations are proposed, offshore exploration and production facilities discharge other wastewaters. These wastes were investigated but are considered to be minor and, more appropriately controlled by NPDES permit limitations. Therefore, no controls for these wastes are promulgated by this rule. These wastes are categorized into the following 14 minor wastes categories:

1) Desalination 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) Mud, cuttings, and cement at the seafloor that result from marine riser disconnect and well abandonment and plugging.

6) Uncontaminated sea water including fire control and utility lift pumps excess water, excess sea water 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) Waterflooding 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.

3.0 CURRENT PERMIT STATUS

Offshore oil and gas structures in the Gulf of Mexico, California, and Alaska are regulated by general and individual permits based on BPT, State water quality, ocean discharge criteria, and on Best Professional Judgment (BPJ) of BCT and BAT levels of control. The general permits and some of the individual permits are based to some degree upon the effluent limitations guidelines proposed in 1985 and for some waste streams are more stringent than the BPT regulations promulgated in 1979.

Requirements in these general permits vary from region to region; however, produced water BPT level limitations are consistently required. The major differences are the requirements covering drilling fluids and cuttings and, to some extent, miscellaneous waste streams such as deck drainage and produced sand. Table III-1 presents a summary of the different requirements for drilling fluids and cuttings contained in the various offshore permits and identifies the bases used in developing current baseline costs and loadings for use in developing the final limitations.

TABLE III-1

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)	Yes	Yes	No
Metals Limitation	Stock Barite[1]	Stock Barite	Stock Barite
Mercury (mg/kg)	1	1	1
Cadmium (mg/kg)	3	2	3
No Discharge of Oil			
for Lubricity	Yes (Diesel)	Yes (Diesel)	Yes (Diesel)
as a Pill	No (Diesel)[2]	No (Diesel)[2]	Yes (Mineral)[3]
Toxicity Limit for Drilling Fluids	30,000 ppm spp[4]	30,000 ppm spp[4]	Yes[5]
No Discharge of "Free Oil"	Visual Sheen	Static Sheen	Static Sheen

[1] The modification to the Region VI OCS general permit for the Central and Western Gulf of Mexico incorporates metals limitations (3 mg/kg Cd, 1 mg/kg Hg in stock barite) for drilling fluids. However, for this rulemaking, the costing and pollutant loadings were developed prior to the modifications and reflect the values presented in the table as current requirements. See 57 *FR* 54642 (Nov. 19, 1992). (Applies to Federal waters seaward of Louisiana and Texas.)
[2] Diesel pill plus 50 bbl buffer of drilling fluid on either side of the pill cannot be discharged; mineral oil can be discharged without a buffer.
[3] Mineral oil pill plus a 50 bbl buffer of drilling fluid on either side of the pill cannot be discharged. Diesel not allowed.
[4] Suspended Particulate Phase
[5] Implemented by the establishment of pre-approved drilling fluids and additives.

4.0 REFERENCES

1. U.S. Department of Interior, Department of Interior News Release, Statement by Secretary of the Interior, Manuel Lujan concerning the President's decisions regarding America's offshore oil and gas program, June 26, 1990. *(Offshore Rulemaking Record Volume 123)*

2. Minerals Management Service, "Federal Offshore Statistics: 1990, Leasing, Exploration, Production and Revenues," prepared by Office of Statistics and Information, Minerals Management Service, U.S. Department of Interior, MM 91-0068.

SECTION IV

INDUSTRY DESCRIPTION

1.0 INTRODUCTION

This section describes the major processes of the offshore oil and gas extraction industry and the current and projected development and production activity. The industry operations are divided into two categories: drilling and production activities. Proper characterization of the technical processes of these two operation categories is essential in defining and characterizing the industry's waste streams.

2.0 DRILLING ACTIVITIES

This section describes the characteristics of the two types of drilling activities: exploration and development. Exploration activities are those operations involving the drilling of wells to determine potential hydrocarbon reserves. Development activities involve the drilling of production wells once a hydrocarbon reserve has been discovered and delineated. Although the rigs used to drill exploration and development wells sometimes differ, the drilling process is generally the same. Table IV-1 presents the annual level of offshore exploration, delineation, and development drilling activity for the years 1973 through 1990.

2.1 EXPLORATORY DRILLING

Exploration for hydrocarbon-bearing reservoirs consists of several indirect and direct methods. Indirect methods, such as geological and geophysical surveys, identify the physical and chemical properties of sediments through surface instrumentation. Geological surveys determine subsurface stratigraphy which identifies rocks typically associated with hydrocarbon bearing reserves. Geophysical surveys indicate the depth and nature of subsurface rock formations and identify underground conditions favorable to oil and gas deposits. There are three types of geophysical surveys: magnetic, gravity, and seismic. These surveys are generally conducted from a boat that has specialized equipment for this purpose. Exploratory drilling is the only way to directly confirm the presence of hydrocarbons and to determine the quantity of hydrocarbons after the surveys indicate hydrocarbon potential. Exploratory wells are also referred to as "wildcats."

TABLE IV-1

OFFSHORE DRILLING ACTIVITY[1]

Year	Number of Wells Drilled	Footage Drilled[a]	Average Well Depth (ft.)
1973	888	8,354,069	9,408
1974	830	7,402,256	8,918
1975	1,028	9,783,176	9,517
1976	1,028	9,817,244	9,550
1977	1,217	11,519,851	9,466
1978	1,197	11,756,744	9,821
1979	1,260	12,392,501	9,835
1980	1,272	12,503,275	9,829
1981	1,476	14,422,470	9,771
1982	1,464	14,537,052	9,930
1983	1,270	12,831,906	10,104
1984	1,421	14,259,153	10,035
1985	1,247	12,815,948	10,277
1986	898	9,407,734	10,476
1987	769	7,345,260	10,360
1988	866	9,334,447	10,779
1989	746	7,721,365	10,350
1990	704	6,963,804	9,892

[a] Includes exploration, delineation, and development drilling.

Exploratory wells may be shallow and drilled in the initial exploratory phase of operations, or they may be deep, seeking to discover the extent of oil or gas bearing reservoirs. These types of exploration activities are usually of short duration at a given site, involve a small number of wells, and are conducted from mobile drilling units. A historical survey of offshore drilling indicates that a total of 7,468 exploratory wells have been drilled as of January 1, 1985. Of these, 5,206 were drilled in Federal waters. Of these, oil was found in 376 cases (5.0%), gas was found in 641 cases (8.6%), and 6,451 (86.4%) were dry holes. Approximately 30 percent of exploratory drilling occurred in State waters and 70 percent in Federal waters.[2]

2.1.1 Drilling Rigs

Mobile offshore drilling units (MODU) are used to drill exploratory wells because they can be easily moved from one drilling site to another. The two basic types of MODUs are bottom-supported units and floating units. Bottom-supported units include submersibles and jackups. Floating units include inland barge rigs, drill ships, ship-shaped barges, and semisubmersibles.[3]

Bottom-supported drilling units are typically used when drilling occurs in shallow waters. Submersibles are barge-mounted drilling rigs that are towed to the drill site and sunk to the bottom. There are two common types of submersible rigs: posted barge and bottle-type.

Jackups are barge-mounted drilling rigs that have extendable legs that are retracted during transport. At the drill site, the legs are extended to the seafloor. As the legs continue to extend, the barge hull is lifted above the water. Jackup rigs can be used in waters up to 300 feet deep. There are two basic types of jackups: columnar leg and open-truss leg.

Floating drilling units are typically used when drilling occurs in deep waters and at locations far from shore. Semisubmersible units are able to withstand rough seas with minimal rolling and pitching tendencies. Semisubmersibles are hull-mounted drilling rigs which float on the surface of the water when empty. At the drilling site, the hulls are flooded and sunk to a certain depth below the surface of the water. When the hulls are fully submerged, the unit is stable and not susceptible to wave motion due to its low center of gravity. The unit is moored with anchors to the seafloor. Semisubmersibles are commonly used for drilling projects in the North Sea and the North Atlantic Ocean. There are two types of semisubmersible rigs: bottle-type and column-stabilized.

Drill ships and ship-shaped barges are vessels equipped with drilling rigs that float on the surface of the water. These vessels maintain position above the drill site by anchors on the seafloor or the use of propellers mounted fore, aft, and on both sides of the vessel. Drill ships and ship-shaped barges are susceptible to wave motion since they float on the surface of the water, and thus are not suitable for use in heavy seas.

2.1.2 Formation Evaluation

The operator is constantly evaluating characteristics of the formation during the drilling process. The evaluation involves measuring properties of the reservoir rock and obtaining samples of the rock and fluids from the formation. Three common evaluation methods are well logging, coring, and drill stem testing. Well logging uses instrumentation that is placed in the wellbore and measures electrical, radioactive, and acoustic properties of the rocks. Coring consists of extracting rock samples from the formation and characterizing the rocks. Drill stem testing brings fluids from the formation to the surface for analysis.[3]

2.2 DEVELOPMENT DRILLING

Development activities involve the drilling of several wells into a reservoir to extract hydrocarbons discovered by exploratory drilling. Several types of drilling rigs are used in developmental drilling operations.. The two most common types of rigs used are the platform rig and the MODU.

Development wells are often drilled from fixed platforms because once the exploratory drilling has confirmed that an extractable quantity of hydrocarbons exist, a platform is constructed at that site for drilling and production operations.

To effectively extract hydrocarbons from the reservoir, several wells are drilled into different parts of the formation. Since all wells must originate directly below the platform, a special drilling technique is used to penetrate different portions of the reservoir. This technique is called controlled directional drilling. Directional drilling involves drilling the top part of the well straight and then directing the wellbore to the desired location. This requires special drilling tools and devices that measure the direction and angle of the hole. Directional drilling also requires the use of special drilling fluids that prevent temperature build up and stuck pipe incidents due to the increased stress on the drill bit and drill string.

2.2.1 Well Drilling

The process of preparing the first few hundred feet of a well is referred to as "spudding." This process consists of extending a large diameter pipe, known as the conductor casing, from a few hundred feet below the seafloor up to the drilling rig. The conductor casing, which is approximately 2 feet in diameter, is either hammered, jetted, or placed into the seafloor depending on the composition of the seafloor. If the composition of the seafloor is soft, the conductor casing can be hammered into place or lowered into a hole created by a high-pressure jet of seawater. In areas where the seafloor is composed of harder material, the casing is placed in a hole created by rotating a large-diameter drill bit on the seafloor. In all cases, the cuttings or solids displaced from setting the casing *are not brought to the* surface and are expended onto the seafloor.

Rotary drilling is the drilling process used to drill the well. The rotary drilling process consists of a drill bit attached to the end of a drill pipe, referred to as the "drill string," which makes a hole in the ground when rotated. Once the well is spudded and the conductor casing is in place, the drill string is lowered through the inside of the casing to the bottom of the hole. The bit rotates and is slowly lowered as the hole is formed. As the hole deepens, the walls of the hole tend to cave in and widen, so periodically the drill string is lifted out of the hole and casing is placed into the newly formed portion of the hole to protect the wellbore. This process of drilling and adding sections of casing is continued until final well depth is achieved.

Rotary drilling utilizes a system of circulating drilling fluid to move drill cuttings away from the bit and out of the borehole. The drilling fluid, or mud, is a mixture of water, special clays, and certain minerals and chemicals. The drilling fluid is pumped downhole through the drill string and is ejected out of nozzles in the drill bit with great speed and pressure. The jets of mud lift the cuttings off the bottom of the hole and away from the bit so that the cuttings do not interfere with the effectiveness of the drill bit. The drilling fluid is circulated to the surface through the casing, or annulus, where cuttings, silt, sand, and any gasses are removed before returning the fluid down-hole to the bit. The cuttings, sand, and silt are separated from the drilling fluid by a solids control process consisting typically of a shaleshaker, desilter, and desander. Figure IV-1 presents a flow diagram of the mud circulation system. Some of the drilling fluid remains with the cuttings after solids control.[4,5] If the cuttings, silt, sand, and residual drilling fluid do not contain free oil; they are discharged overboard. Cuttings contaminated with oil from the formation or from an oil-based mud are stored in cuttings boxes and brought to shore for disposal.

Drilling fluids function to cool and lubricate the bit, stabilize the walls of the borehole, and maintain equilibrium between the borehole and the formation pressures. The drilling fluid must exert a higher pressure in the wellbore than in the surrounding formation, otherwise fluids from the formation (water, oil, and gas) will migrate from the formation into the wellbore, and potentially create a blowout. A blowout occurs when drilling fluids are ejected from the well by subsurface pressures and the well flows uncontrolled.

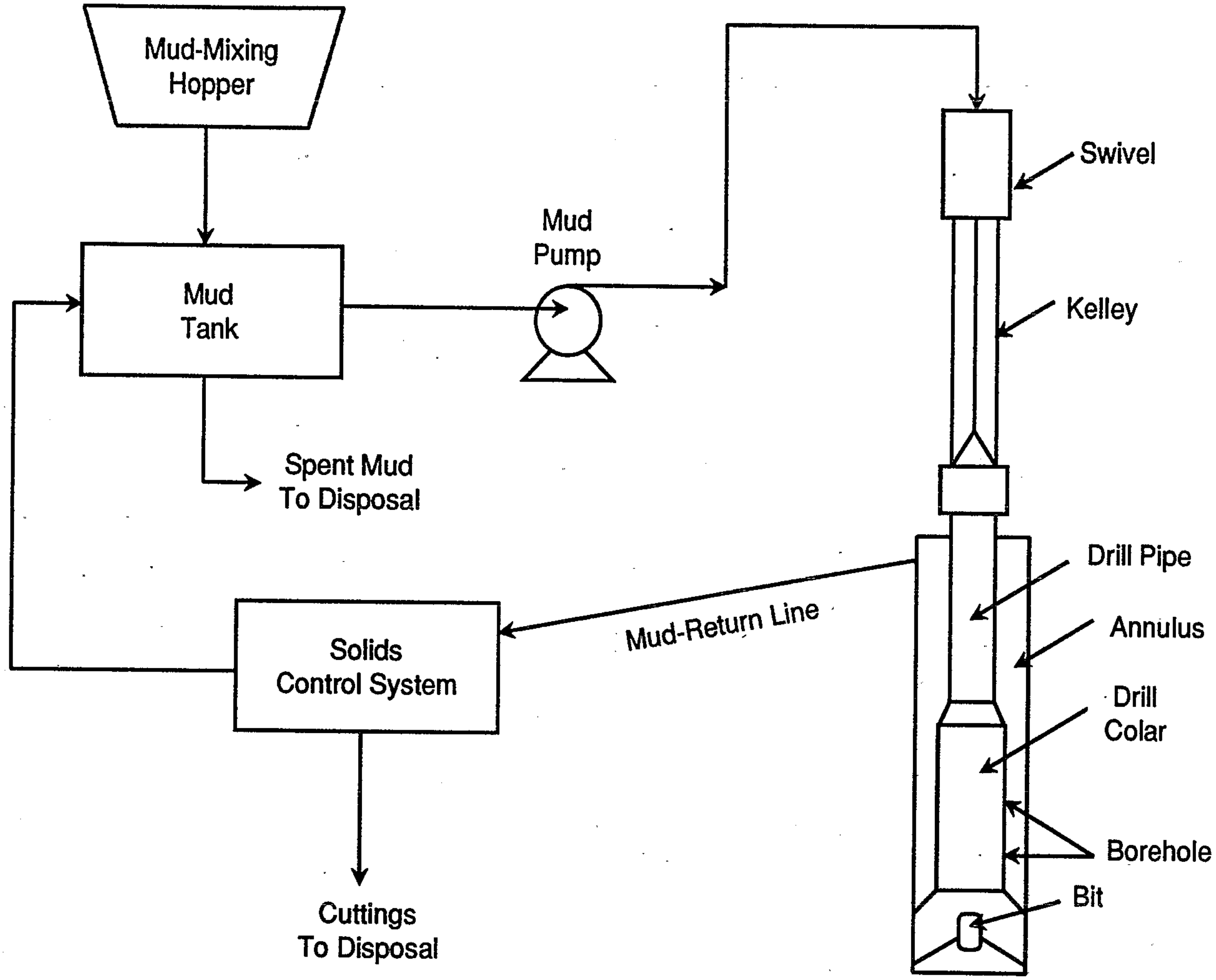

Figure IV-1
Typical Drilling Fluids Circulation System

To prevent well blowouts, high pressure safety valves called blowout preventers (BOPs) are attached at the top of the well. Since the formation pressures vary at different depths, the density of the drilling fluid must be constantly monitored and adjusted to the downhole conditions during each phase of the drilling project. Other properties of the drilling fluid, such as lubricity, gel strength, and viscosity, must also be controlled to satisfy the drilling conditions. The mud must be replaced if the drilling fluid cannot be adjusted to meet the downhole drilling conditions. This is referred to as a "mud changeover."

The solids control process is necessary to maintain constant mud characteristics and/or change them as required by the drilling conditions. The ability to remove drill solids from the drilling fluid, referred to as "solids control efficiency," is dependent on the equipment and the formation characteristics. Poor solids removal efficiencies result in increased drilling torque and drag, increased tendency for stuck pipe, increased mud costs, and reduced wellbore stability. Mud dilution is a common method for reducing the percentage of solids remaining in the circulating mud system that are not removed mechanically via shaleshakers and hydrocyclones. Mud dilution involves thinning the mud with water and rebuilding the desired rheological properties of the mud with additives. The disadvantages of dilution are that the portion of the mud removed from the circulating system must be stored or disposed and greater quantities of mud components are necessary to formulate the replacement mud. Both of these add expenses to the drill project.

Most drilling fluid systems are water-based, although oil-based systems are still used for specialized drilling projects. In the 1970's, drilling fluids were mostly oil-based. The trend away from oil-based muds is due to the BPT limitations on the discharge of free oil and in advancements in water-based fluids technology. Until recently, only oil-based muds could achieve the temperature stability and lubricity properties required by special drilling conditions such as directional and deep well drilling. However, advancements in drilling fluid technology have enabled operators to formulate water-based muds with similar properties to that of oil-based muds through the use of small quantities of oil and/or synthetic additives. Small quantities of oil and/or synthetic additives are used to enhance the lubricity of a water-based mud system and to aid in freeing stuck drill pipe. In the past, diesel oil was solely used for enhancing lubricity and freeing stuck pipe because of its properties and the fact that it is often the most readily available oil at a drilling site. However, mineral oil and synthetic lubricants have replaced diesel oil because of diesel's known toxicity. When oil or a synthetic spotting fluid is used as an aid in freeing stuck drill pipe, a standard technique is to pump a slug or "pill" of oil or oil-based fluid down the drill string and "spot" it in the annulus area where the pipe is stuck. Most of the pill can be removed from the bulk mud system and disposed of separately. However, one hundred percent removal of the pill is not possible and a portion of the spotting fluid remains with the mud system.

The most significant waste streams, in terms of volume and constituents associated with drilling activities are drilling fluids and drill cuttings. Drill cuttings are generated throughout the drilling project, although higher quantities of cuttings are generated during drilling of the first few thousand feet of the well because the borehole is the widest during this stage. The largest quantities of excess drilling fluids are generated as the project approaches final well depth. Fluids are generated during the drilling process because of displacement due to solids control and smaller volumes required due to the decreasing borehole diameter. Fluid generation is the largest at well completion because the entire mud system must be removed from the hole and the mud tanks. Some constituents of the drilling fluid can be salvaged after completion of the drilling program. Salvage facilities may exist at the rig or at another location such as the industrial facility that supplies the drilling fluids. Where drilling is continuous, such as on a multiple-well offshore platform, the mud can be conditioned and reused from one well to another.

3.0 PRODUCTION ACTIVITIES

This section details the activities and processes associated with extracting hydrocarbons from the formation and processing the fluid for transportation to shore. The activities and processes described in this section are fluid extraction, well completion, fluid separation, well treatment, and workover.

3.1 FLUID EXTRACTION

The fluid produced from oil reservoirs consists of oil, natural gas, and salt water or brine. Gas wells may produce dry gas, but usually also produce varying quantities of light hydrocarbon liquids (known as gas liquids or condensate) and salt water. The water contains dissolved and suspended solids, hydrocarbons, metals, and may contain small amounts of radionuclides. Suspended solids consist of sands, clays, or other fines from the reservoir.

Crude oil can vary widely in its physical and chemical properties. Two important properties are its density and viscosity. Density usually is measured by the "API gravity" method which assigns a number to the oil according to its specific gravity. Oil can range from very light gasoline-like materials (called natural gasolines) to heavy, viscous asphalt-like materials.

Production fluids flow to the surface through tubing inserted *within the cased borehole. For oil* wells, the energy required to lift the fluids up the well is supplied by the natural pressures in the formation, known as natural drive. There are four kinds of natural drive mechanisms found with oil and gas production: dissolved-gas drive, gas-cap drive, water drive, and combination gas and water drive.

As hydrocarbons are produced, the natural pressures in the reservoir decrease and additional pressure must be added to the reservoir to extract the fluids. Additional pressure can be provided artificially to the reservoir by various operations at the surface. The most common methods of artificial lift are the following three: (1) gas lift, which is injection of gas into the well in order to lighten the column of fluid in the borehole and assist in lifting the fluid from the reservoir as the gas expands while rising to the surface; (2) waterflooding, which is the injection of fluids into the reservoir to maintain formation pressures that otherwise drop during the withdrawal of the formation fluids; and (3) employment of various types of pumps in the well itself. As the fluids in the well rise to the surface, they flow through a series of valves and flow control devices that make up the well head.

3.1.1 Enhanced Oil Recovery

When an oil field is depleted by primary and secondary methods (e.g., natural flow, artificial lift, waterflooding), as much as 50 percent of the original oil may remain in the formation. Enhanced oil recovery (EOR) processes have been developed to recover a portion of this remaining oil. The EOR processes can be divided into three general classes: (1) thermal, (2) chemical, and (3) miscible displacement.

Thermal: Thermal processes include steam stimulation, steam flooding, and *in situ* combustion. Steam stimulation and flooding processes differ primarily in the number of wells involved in a field. Steam stimulation uses an injection-wait-pump cycle in a single well, whereas the steam flooding process uses a continuous steam injection into a pattern of wells and continuous pumping from other wells within the same pattern. The *in situ* combustion process uses no other chemicals than the oxygen required to maintain the fire.

Chemical: Chemical EOR processes include surfactant-polymer injection, polymer flooding, and caustic flooding. In the first process, a slug of surfactant solution is pumped down the injection well followed by a slug of polymer solution to act as a drive fluid. The surfactant "washes" the oil from the formation, and the oil/surfactant emulsion is pushed toward the producing well by the polymer solution.

In polymer flooding, a polymer solution is pumped continuously down the injection well to act as both a displacing compound and a drive fluid. Surfactant and polymer injection may require extensive treatment of the water used in solution make-up before the surfactant or polymer is added. Caustic flooding is used to drive oil through a formation toward producing wells. The caustic is delivered to the injection wells via a manifold system; the injection head is similar to that used in steam flooding.

Miscible displacement: These EOR processes use an injected slug of hydrocarbon (e.g., kerosene) or gas (e.g., carbon dioxide) followed by an immiscible slug (e.g., water). The miscible slug dissolves crude oil from the formation and the immiscible slug drives the lower viscosity solution toward the producing well. The injection head and manifold system are similar to those used for steam flooding.

3.2 COMPLETION

Completion operations include the setting and cementing of the production casing, packing the well and installing the production tubing. The completion process installs equipment in the well which allows hydrocarbons to be extracted from the reservoir. Completion methods are determined based on the type of formation, such as hard sand, loose sand, fine grain loose sand, and loose fine and coarse grain sands. Bridging agents are used to prevent fluid loss from the well to the formation.[6,7]

There are two types of completions, open hole and cased hole. Open hole completions are performed on consolidated formations. Cased hole completions are performed on unconsolidated formations. The majority of completions in the Gulf of Mexico are cased hole.[8] Figure IV-2 presents schematic diagrams of four common completion methods for different formation characteristics.

The completion process consists of the following steps: wellbore flush, production tubing installation, casing perforation, and wellhead installation. The following paragraphs give a brief description of each of these steps.

The initial wellbore flush consists of a slug of seawater that is injected into the casing. These fluids are considered cleaning or pre-flush fluids and can be circulated and filtered many times to remove solids from the well and minimize the potential for damage to the formation.[9] When the well has been cleaned, a second completion fluid termed a "weighing fluid" is injected. This fluid maintains sufficient pressure to prevent the formation fluids from migrating into the hole until the well completion is finished.

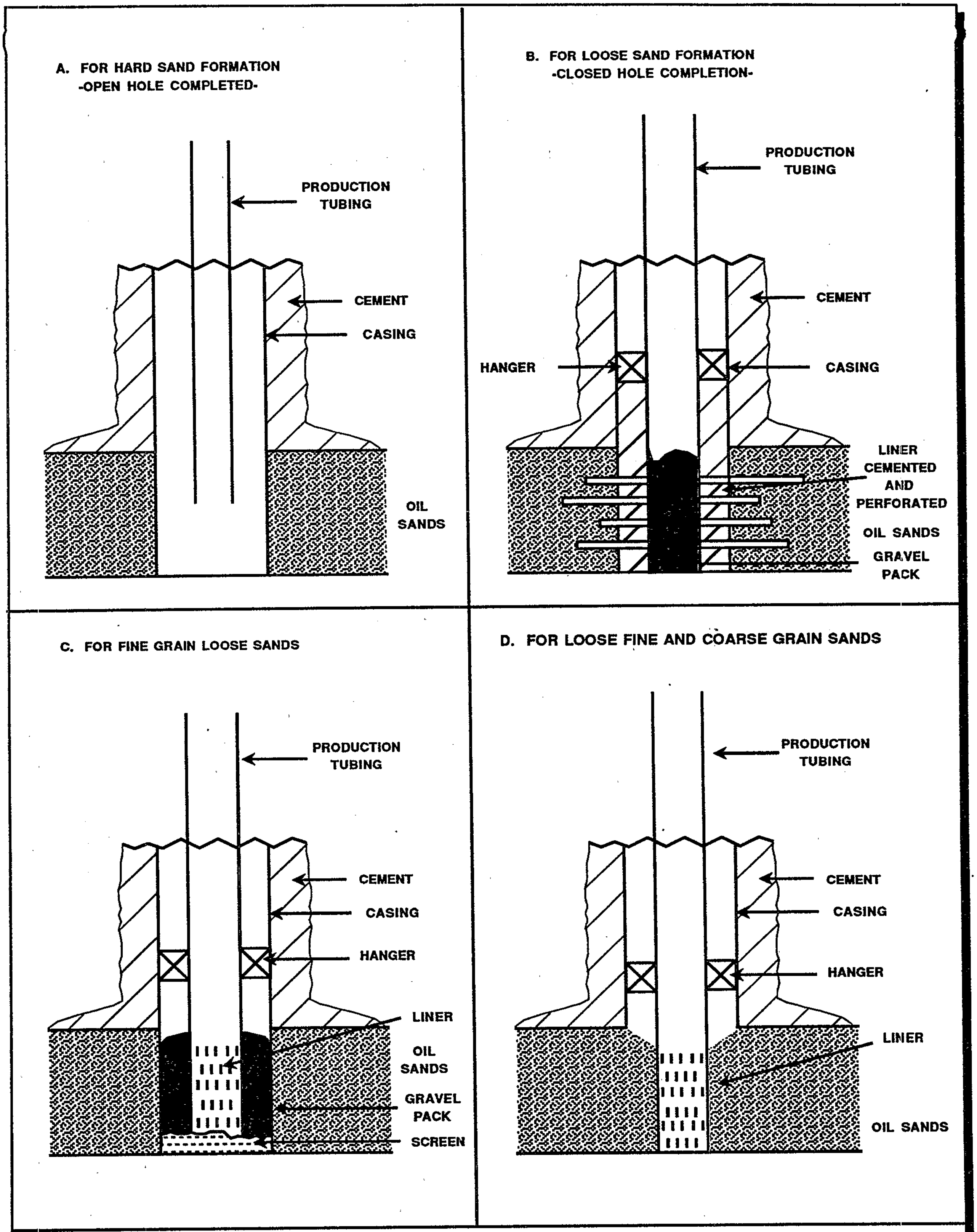

Figure IV-2
Typical Completion Methods

Production tubing is then installed inside the casing using a packer which is placed at or near the end of the tubing. The packer consists of pipe, gripping elements, and sealing elements made of rubber that keep the tubing in place and expand to form a pressure-tight seal between the production tubing and the well casing.[3,10] This seals off the annular space and forces the reservoir fluids to flow up the tubing and not into the well annulus.

Packer fluids are completion fluids that are trapped between the casing and the production tubing by the packer. They can provide long-term corrosion protection. Packer fluids are typically mixtures of a polymer viscosifier, a corrosion inhibitor, and a high concentration salt solution.[11] Packer fluids remain in place and may be removed during workover operations.[12]

The production tubing must then be perforated to allow the formation fluids to flow into the wellbore. The most common method of cased hole completion is perforation. The casing in the well is perforated to allow the hydrocarbons to flow from the reservoir to the well. Perforation may be accomplished with the use of a special perforating gun (usually lowered into the well by wireline) that fires steel bullets or shaped charges which penetrate the casing and cement. An additional means of perforation is achieved by suspending a small perforated pipe from the bottom of the casing.[3,10]

The final step in well completion is the installation of the "Christmas tree," a device that controls the flow of hydrocarbons from the well. The Christmas tree may be installed on the platform (a surface completion) or below the waterline on or below the seafloor (a subsea completion). When the valves of the Christmas tree are initially opened, the completion fluids remaining in the tubing are removed and fluid flow from the formation begins.

3.3 FLUID SEPARATION

At the surface, the constituents of the formation fluids, or production fluids, are separated: gas from liquids, oil from water, and solids from liquids. The gas, oil, and water may be separated in a single vessel or, more commonly, in several stages. Gas dissolved in oil is released from solution as the pressure of the fluid drops. Fluids from high-pressure reservoirs may be passed through a number of separating stages at successively lower pressures before oil is free of gas. The oil and brine do not separate as readily as the gas does. Usually, a quantity of oil and water is present as an emulsion. This emulsion may occur naturally in the reservoir or can be caused by the extraction process which tends to mix the oil and water vigorously. The passage of the fluids into and up the well, through wellhead chokes, various pipes, headers, and control valves into separation chambers, and through any centrifugal pumps in the system, tends to increase emulsification. Moderate heat, chemical addition, quiescent settling, and/or electrical charges tend to cause the emulsified liquids to separate.

The produced water treatment system is a series of vessels in a multistage separation process. Figure IV-3 presents a flow diagram of a typical produced water treatment system. The first stage of the produced water treatment system is a bulk separator. The bulk separator separates the produced fluid into gas, oil and water. The gas stream is drawn off the top of the vessel, the oil stream off the middle, and the water stream off the bottom. A schematic diagram of a bulk separator in presented in Figure IV-4. Bulk separators are often arranged in series because gas comes out of solution as the pressure drops.

High-, intermediate-, and low-pressure separators are the most common arrangement, with the high-pressure liquids passing through each stage in series and gas being taken off at each stage. Production fluids are processed in the appropriate stage of the bulk separation process. The separated gas is dehydrated in a glycol dehydrator and then used for electrical power generation, gas lift operations, or transported to shore via pipeline. The oil separated in the bulk separator is piped to an oil treatment unit for further treatment. The water separated in the bulk separator is piped to a water treatment unit for further oil-water separation.

The oil treatment unit is often referred to as a heater treater or chem-electric. This unit receives the product oil stream from the bulk separator and is designed to remove residual water from the oil through gravity separation aided by heat and/or the addition of chemicals to enhance and accelerate separation. Heat and/or emulsion-breaking chemicals are almost always necessary to break the emulsions present in the oil treatment unit to assure low water content in the oil product (most pipelines have water content limitations on the oil that can be transported in the pipelines). Oil is drawn off the top of the oil treatment unit and sent to the oil product vessel before being piped to shore. Water is removed from the bottom of the oil treatment unit and piped to the water treatment unit.

The water treatment unit receives produced water from the bulk separator and the oil treatment unit. The water treatment unit is also referred to as a "precipitator." The produced water entering this unit contains small quantities of residual oil. The water treatment unit is typically a long horizontal vessel with quiescent conditions allowing for gravity separation. The vessel contains mostly water and the separated oil floats to the surface of the water. An oil layer accumulates in the top portion of the vessel. Oil is periodically removed from the top of the vessel and piped to the oil treatment unit. Water is drawn

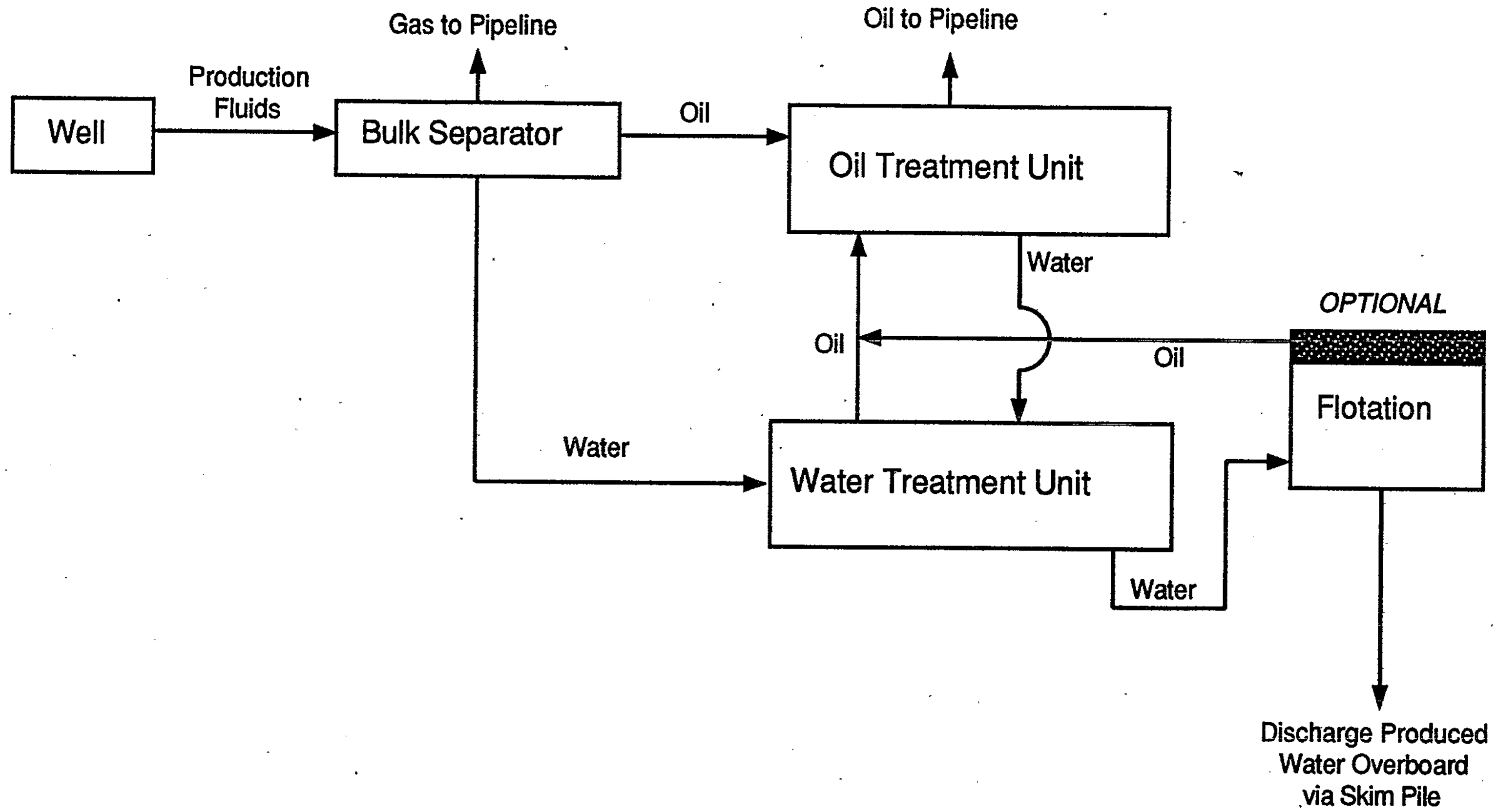

Figure IV-3
Produced Water Treatment System

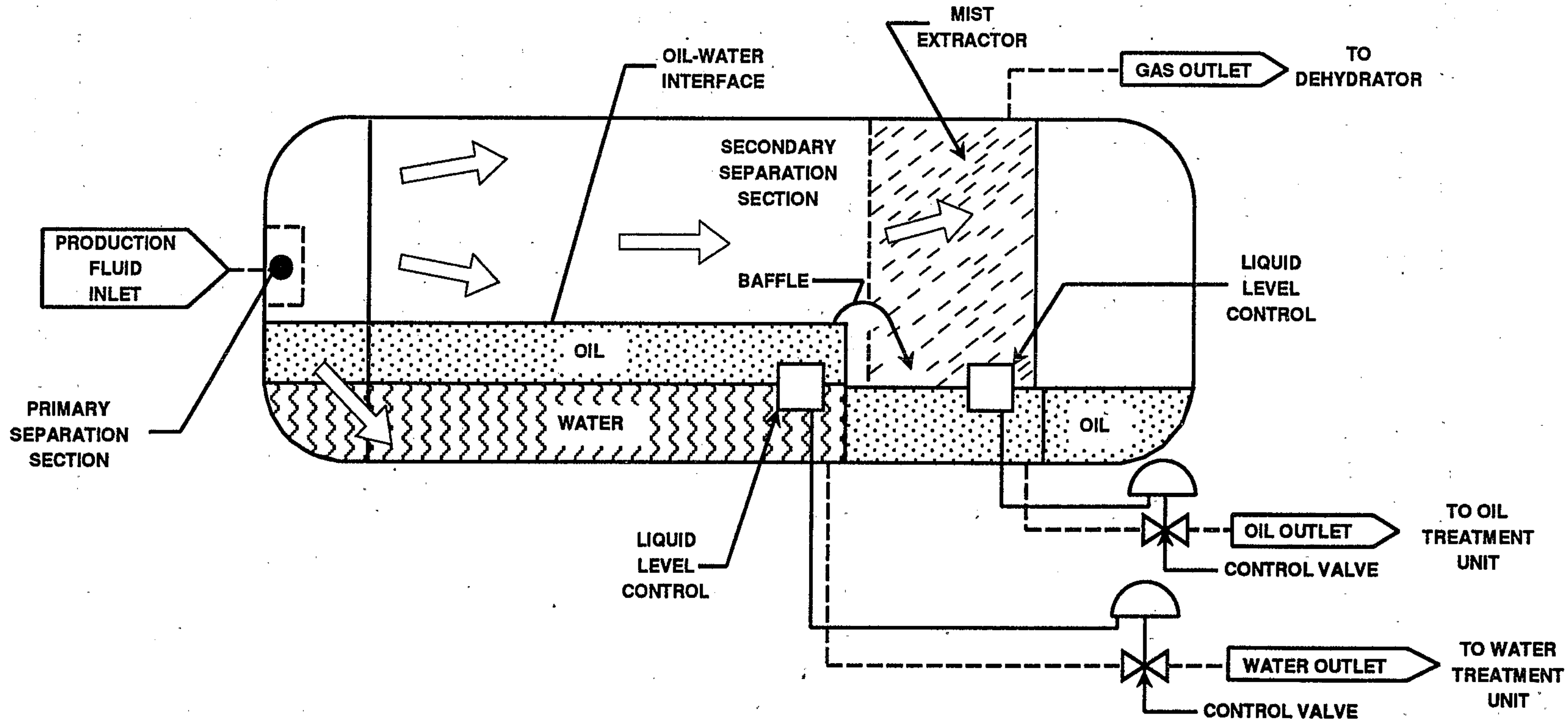

Figure IV-4
Bulk Separator

off the bottom of the vessel and discharged overboard through the skim pile if the effluent meets the BPT oil and grease limitations.

If the water treatment unit does not provide sufficient treatment to meet the BPT oil and grease limitations, additional water treatment units are used in conjunction with the separation process. The most common treatment processes used in the offshore industry are gas flotation and coalescers. A detailed discussion of these and other produced water treatment technologies is presented in Section IX.5.1.

The major waste stream associated with production activities is the produced water stream. Produced sand or production solids is another waste stream of lesser volume. Both waste streams originate with the production fluids and are separated from the oil product in the produced water treatment system.

3.4 WELL TREATMENT

Well treatment is the process of stimulating a producing well to improve oil or gas productivity. There are two basic methods of well treatment, hydraulic fracturing and acid treatment. The specific method is chosen based on the characteristics of the reservoir, such as type of rock and water cut.[10] A well treatment job will enlarge the existing channels within the formation and increase the productivity of the formation. Typically, hydraulic fracturing is performed on sandstone formations,[10] and acid treatment is performed on formations of limestone or dolomite.[7]

Hydraulic fracturing injects fluids into the well under high pressure, approximately 10,000 pounds per square inch. This causes openings in the formation to crack open, increasing their size and creating new openings. The fracturing fluids contain inert materials referred to as "proppants," such as sand, ground walnut shells, aluminum spheres, and glass beads, that remain in the formation to prop the channels open after the fluid and pressure have been removed.[7,13] Hydraulic fracturing is rarely done in offshore operations because the unconsolidated sandstone formations in the Gulf of Mexico do not require fracturing and the operation requires significant logistical support (i.e., deck space, pumps, mixing equipment, etc.) that is expensive to provide offshore.[4]

Acid stimulation is done by injecting acid solutions into the formation. The acid solution dissolves portions of the formation rock, thus enlarging the openings in the formation. The two most common types of acid treatment are acid fracturing and matrix acidizing. Acid *fracturing utilizing high* pressures results in additional fracturing of the formation. Matrix acidizing uses low pressures to avoid fracturing the formation. The acid solution must be water soluble, safe to handle, inhibited to minimize damage to the well casing and piping, and inexpensive.[7]

In addition to well treatment using hydraulic fracturing and acidizing, chemical treatment of a well may also be performed. Well treatment with an organic solvent like xylene or toluene will remove paraffin or asphalt blocks from the wellbore. These deposits of solid hydrocarbons occur due to the decrease in temperature and pressure when the liquid hydrocarbons are extracted from the well.[14]

3.5 WORKOVER

Workover operations are performed on a well to improve or restore productivity, evaluate the formation, or abandon a well.[8] Loss of productivity can be the result of worn out equipment, restricted fluid flow due to sand in the well, corrosion, malfunctions of lift valves, etc. Several sources indicated that workover operations include well pulling, stimulation (acidizing and fracturing), washout, reperforating, reconditioning, gravel packing, casing repair, and replacement of subsurface equipment.[7,15,16] One source indicates that a well will require workover operations every 3-5 years[16] and another indicates that the average well receives treatment or is worked over approximately every 4 years.[6] The need for workover is related to the percentage of brine in the production fluids. Workover can be performed as often as every 2 years in wells producing greater than 50 percent brine.[9]

The four general classifications of workover operations are pump, wireline, concentric, and conventional.[8] Workovers can be performed using the original derrick from the drilling platform, a mobile workover rig, or by wireline. The operation is begun by forcing the production fluids back into the formation to prevent them from exiting the well during the operation. Then tools and devices can be attached to the wireline (a spool of strong fine wire) and lowered and pulled from the well to perform the require operations.

4.0 PRODUCTION AND DRILLING: CURRENT ACTIVITY AND FUTURE PROJECTIONS

4.1 INDUSTRY SUBCATEGORIZATION

In evaluating the feasibility and costs of the various treatment technologies being considered, EPA developed subcategories, or sectors, within the offshore subcategory. These subcategories are based on water depth or distance from shore of the production platform or the location of the drilling project.

In 1985, EPA presented an industry subcategorization based on a structure's location in shallow or deep waters. EPA proposed variable depth limits for different offshore areas and evaluated several regulatory options related to the shallow/deep subcategorization. This evaluation discovered certain nonwater-quality impacts associated with the options that warranted further investigation and/or consideration of a change in the subcategorization scheme. In an effort to mitigate potential nonwater-quality environmental impacts, EPA developed a subcategorization based on distance from shore.

In the 1991 proposal, EPA presented a subcategorization based on distance from shore. EPA developed profiles based on 3, 4, 6, and 8 miles from shore. The distance from shore approach to industry subcategorization has enabled EPA to consider various options of the treatment technologies considered for this rulemaking, while minimizing the associated nonwater-quality environmental impacts.

4.1.1 Industry Profile

For each geographical region, the industry was characterized as consisting of a platform population divided among different platform structure types, or model platforms. A model platform is defined by the number of available well slots on the platform. Each producing well is brought to the wellhead on the platform through a dedicated well slot. Platforms are constructed with a fixed number of well slots. Well slots that are not producing are considered dry holes. The number of dry holes was determined from the difference between the number of slots on the platform and the number of producing well slots. The count of the total number of platforms, including the number of well slots versus the number of producing well slots on each platform, was generated by EPA using data compiled from the following sources: the MMS Platform Inspection Complex/Structure database, the California Division of Oil and Gas, and the California Coastal Commission.

The model platforms were further divided into three production type categories: (1) oil facilities, (2) oil and gas facilities, and (3) gas facilities. For each model platform EPA reported the number of producing wells and the quantity of produced water generated using data compiled from the MMS Complex/Structure Data Base.

Appendix 1 presents the industry profiles for the 3- and 4-mile from shore delineation. These profiles contain regional information on the number of platforms, the number of producing wells, the average daily produced water flow rate, and the maximum daily produced-water flow rate.

4.2 EXISTING PLATFORMS

EPA's industry profile estimates reflect structures that would incur costs under this rulemaking effort. The estimate of existing structures includes only those platforms meeting the following guidelines: (1) in production, (2) with specific products (i.e., oil, gas, or both), (3) with a specific number of wells drilled or in production, (4) discharging, and (5) in the offshore subcategory. For the Gulf of Mexico, two major sources of data are used. EPA conducted a mapping effort to identify structures in production in the offshore subcategory of State waters. Using maps and electronic data, EPA accomplished the following: (1) identified wells whose wellhead location lay seaward of the baseline that separates the coastal and offshore subcategories, (2) identified wells belonging to common platforms, and (3) verified which wells were still in production. This effort was undertaken to fill a data gap that existed at the time of the March 1991 proposal and identified an additional 284 structures. The second data source, the March 1988 version of the "Minerals Management Service (MMS) Platform Inspection System, Complex/Structure Data Base," was used to estimate the number of structures in the Federal waters of the Gulf of Mexico that are likely to bear costs under this rulemaking effort. The estimated count of 2,233 in structures in Federal waters in the Gulf of Mexico is unchanged from the March 1991 proposal. For the Pacific, 32 structures are included in the BAT count of existing structures. There are no structures in the Atlantic at this time. Structures off Alaska in Cook Inlet are in the coastal subcategory and are not included in this rulemaking. Currently, there is only one existing project in Alaskan waters that is seaward of the inner boundary of the territorial seas. This facility is already required by State regulations to reinject produced water; incremental compliance costs associated with this regulation are minimal. No existing Alaskan structures are projected to incur significant incremental compliance costs under this rule. A total of 2,549 offshore structures is used in the BAT analysis. Table IV-2 presents the estimated number of existing structures.

TABLE IV-2

EXISTING STRUCTURES IN OFFSHORE WATERS

	Distance from Shore (nautical miles)			
	0-3	3-4	> 4	Total
Gulf of Mexico	120	209	2,107	2517
California	10	3	11	32
Alaska	0	0	0	0
Total	211	212	2,118	2,549

4.3 NEW SOURCES

4.3.1 Drilling Activity

Offshore drilling efforts vary from year to year depending on such factors as the price and supply of oil, the amount of State and Federal leasing, and reservoir discoveries. EPA estimates future drilling activity averaging 759 wells per year during the 15-year period, from 1993-2007, after the regulation. Estimated activity in the Gulf of Mexico and Alaska are based on MMS 30-year regionalized forecasts with an average barrel of oil equivalent (BOE) price of $21/bbl (1986 dollars) for the 15-year period.

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

The projection of 759 wells drilled per year includes all new wells - productive, non-productive, exploratory, and development. The well projections therefore include both BAT and NSPS wells. BAT wells are exploratory wells and development and production wells for which significant site preparation takes place immediately prior to the promulgation of the regulation. NSPS includes any facility or activity of this subcategory where the process of surveying, clearing, or preparing an area of the ocean floor for the purpose of constructing or placing a development or production facility on or over the site has commenced after promulgation of the regulation. Table IV-3 is a summary of the BAT and NSPS wells by region. Approximately one-third of the new wells may be classified as existing sources. (The actual percentage of wells classified as existing sources will vary in time. Most will be exploratory efforts. The number of new wells drilled on existing platforms will decrease in time as those platforms complete their drilling programs. The numbers given in Table IV-3 reflect the annual average number of wells during the 15-year period after promulgation of the regulation.)

TABLE IV-3

AVERAGE ANNUAL NEW WELL DRILLING
(Wells/Year)

Region	Existing Sources	New Sources	Total
Gulf	251	500	715
Pacific	32	0	32
Alaska	3	9	12
Total	250	509	759
Percent	33%	67%	

4.3.2 Production

Platform projections were made based on the number of productive wells. An estimated 759 platforms are installed during the 15-year period after promulgation of the regulation. The fact that the estimated annual average number of wells (759) is the same as the total number of platforms (759) installed during the 15-year period is coincidental. Table IV-4 presents the total projected new structures.

TABLE IV-4

TOTAL PROJECTED NEW STRUCTURES - (1993-2007)

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

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SECTION V

DATA AND INFORMATION GATHERING

1.0 INTRODUCTION

The data gathering efforts conducted for the 1985 rulemaking focused on toxic pollutant effluents from produced water, drilling fluids, and drill cuttings. In addition, EPA evaluated wastes associated with the offshore development and production industry for certain conventional and nonconventional pollutants.

Several areas were identified that required further study to support the 1985 proposal of effluent limitations guidelines and standards. These included: an evaluation of priority pollutant levels in produced water discharges, an evaluation of alternative produced water control and treatment technologies, a characterization of drilling fluids and additives, an investigation of alternative disposal practices for drilling fluids and drill cuttings, an assessment of the impacts of discharging drilling and production wastes into the marine environment, and updated projections on the location, size, and configuration of new sources.

Since the 1985 proposal, EPA has acquired additional information on oil and gas effluents and their treatment technologies. Such information has been obtained by way of public comments, industry data, and EPA-sponsored studies. Much of this information was discussed in a *Federal Register* Notice of Data Availability and request for comments (53 *FR* 41356) in October 1988. In response to public comments on the 1985 proposal and the 1988 notice, EPA reproposed BCT, BAT, and NSPS limitations on March 13, 1991 (56 *FR* 10664). The 1991 proposal did not supersede the 1985 proposal entirely. The 1985 proposal was revised in certain areas based on information that had been acquired regarding: waste characterization, treatment technologies, industrial practices, industry profiles, analytical methods, environmental effects, compliance costs, and economic impacts.

The major studies presenting information on offshore oil and gas effluents and treatment technologies which have bearing on the final rule are summarized in the following sections.

2.0 DRILLING FLUIDS AND DRILL CUTTINGS

2.1 CHARACTERIZATION OF WATER-BASED DRILLING FLUIDS

In 1983, EPA initiated a program to evaluate the characteristics of water-based drilling fluids. Water-based drilling fluids may be broadly classified as either clay muds (those that depend on clay for viscosity) or polymer muds (those that depend on polymer for viscosity). The program evaluated the acute toxicity of water-based muds and the physical and chemical characteristics of water-based muds and drill cuttings from water-based muds. The program also included an evaluation of the organic chemical characterization of diesel and mineral drilling fluid additives. In addition to the characterization of water based drilling fluids, the program examined the test procedures that were being proposed as analytical methods for measuring acute toxicity and for detecting the presence of diesel oil in drilling fluids.

The basis of the program was the selection of the types of water-based muds to be analyzed. The primary criteria of the mud selection process was to select the most common types of muds being used in the offshore industry. The mud selection process included information gathered during the development of the Mid-Atlantic NPDES drilling permit issued in 1978 and guidance from the Petroleum Equipment Suppliers Association (PESA).[1] The final set of muds selected consisted of eight generic muds whose characteristics encompass the spectrum of water-based muds used in offshore drilling operations. The formulations of the eight generic muds selected for analysis did not include specialty additives, however two of the generic muds were evaluated with different concentrations of mineral oil ranging from 0 to 10 percent by volume. The generic muds were formulated by PESA and sent to two different laboratories for analysis. Table V-1 presents descriptions for the eight generic muds selected for the program.[2] The EPA's Environmental Research Laboratory in Gulf Breeze, Florida, "Gulf Breeze," performed the acute toxicity testing and an EPA contract laboratory performed the physical and chemical analyses.

The Gulf Breeze laboratory conducted acute toxicity testing of the eight generic muds with mysid shrimp (*Mysidopsis bahia*) during August and September of 1983. To confirm the validity of the toxicity tests conducted at Gulf Breeze, two of the drilling fluids were tested at the EPA's Environmental Research Laboratory in Narragansett, Rhode Island. The test material was the suspended particulate phase (SPP) of each fluid. The SPP was prepared by mixing volumetrically 1 part drilling fluid to 9 parts seawater and allowing the resulting slurry to settle for one hour. A positive control, in which mysid shrimp were exposed to the reference toxicant (sodium lauryl sulfate), was maintained for each drilling fluid toxicity test.[3]

TABLE V-1

GENERIC MUD DESCRIPTIONS[2]

GENERIC MUD	NATURE AND UTILITY
1. Potassium/polymer	An inhibitive mud used for drilling through soft formations like shale where sloughing may occur. Polymers are used to maintain their viscosity. These fluids require little thinning with fresh or salt water.
2. Seawater/lignosulfonate	An inhibitive mud that functions well under a variety of conditions. This mud maintains viscosity by binding lignosulfonate cations onto the broken edges of clay particles, reducing flocculation and maintaining gel strength. This mud can control fluid loss and maintain borehole stability. They are easily altered for more complicated downhole conditions, e.g., higher temperatures.
3. Lime (or calcium)	An inhibitive mud in which calcium binds onto clay. The clay platelets are pulled together, dehydrating them and releasing absorbed water. The size of the particles is reduced, and water is released, resulting in reduced viscosity. More solids may be maintained in these systems with a minimum of viscosity and gel strength. These fluids are used in hydratable, sloughing shale formations.
4. Nondispersed	An inhibitive mud in which acrylic serves to prevent fluid loss and maintain viscosity. This mud also provides improved penetration, which is impeded by clay particles in dispersed fluids.
5. Spud	A noninhibitive, simple mixture used in the first 1,000 (300m) or so of drilling.
6. Seawater/freshwater gel	An inhibitive mud used early in drilling or in simple drilling situations. This mud provides good fluid control, shear thinning, and lifting capacity. Prehydrated bentonite that flocculates is used in such freshwater or saltwater fluids. Attapulgite is used in saltwater fluids when fluid loss is not important.
7. Lightly treated lignosulfonate freshwater/seawater	This mud resembles seawater/lignosulfonate fluids (type 2) except that the salt content is less. The viscosity and gel strength of these fluids are adjusted through additions of lignosulfonate and caustic soda.
8. Lignosulfonate freshwater	This mud resembles fluid types 2 and 7, except that lignosulfonate concentrations are higher. These fluids are suited to high-temperature drilling. Increased concentrations of lignosulfonate will result in heavily treated fluids of this type.

The physical and chemical analyses were conducted on the eight generic muds without any additives and on an additional six mud compositions with varying degrees of mineral oil. The EPA contract laboratory also analyzed drill cuttings from oil-based muds and additional drilling fluid samples with varying degrees of diesel and mineral oils. A total of 34 mud samples were shipped to the EPA contract lab by the industry. These muds consisted of generic formulations with no additives, with varying concentrations of mineral oil, with varying concentrations of an emulsifier, and with varying concentrations of diesel oil. Also analyzed were six samples of washed and unwashed drill cuttings from three drilling operations in the Gulf of Mexico. The drill cuttings were from drilling programs using oil-based (mineral and diesel) mud systems. The physical and chemical analyses consisted of the following parameters: biological oxygen demand, total organic carbon, chemical oxygen demand, sheen test, oil and grease, organics, and metals.[4]

Table V-2 presents a list of the muds and cuttings analyzed for toxity and for chemical composition.

2.2 AMERICAN PETROLEUM INSTITUTE DRILLING FLUIDS SURVEY

In 1983, the American Petroleum Institute (API) conducted a survey among eleven offshore operators in the Gulf of Mexico to obtain information on diesel and mineral oil usage in water-based drilling fluids. Because the number of mineral oil applications in 1983 was small, API conducted an additional survey in 1984 to obtain more data on mineral oil usage.[5]

The survey data indicate that mineral oil is more commonly used as a lubricant, while diesel oil is more commonly used for spotting purposes. Data from the 1983 survey indicated that diesel oil was used for spotting purposes in 79 percent of all pills, and mineral oil was used in 21 percent of all pills using hydrocarbons. The survey indicated that the success rate of freeing stuck pipe was 48 percent for diesel oil pills and 33 percent for mineral oil pills. Data from the 1984 survey indicated that hydrocarbons (diesel or mineral oil) were added for lubricity in 12 percent of all water based fluids. Mineral oil and diesel oil were used in 8 percent and 4 percent of the wells, respectively. For drilling fluids, to which a hydrocarbon-based lubricity agent was added, typically 3 percent (by volume) of the mud formulation was composed of a hydrocarbon additive. The data also indicated that in 1984, 47 percent of all wells drilled used a water-based drilling fluid.

TABLE V-2

SUMMARY OF DRILLING FLUIDS ANALYSIS PROGRAM[4]

EPA ID	Sample Description	Toxicity Testing	Chemical Analysis	Pass Static Sheen
	Generic Muds			
1	Seawater/Potassium/Polymer Mud	Yes	Yes	Pass
2	Seawater/Lignosulfonate Mud	Yes	Yes	Pass
3	Lime Mud	Yes	Yes	Pass
4	Nondispersed Mud	Yes	Yes	Pass
5	Spud Mud	Yes	Yes	Pass
6	Seawater/Freshwater Gel Mud	Yes	Yes	Pass
7	Lignosulfonate Freshwater/Seawater Mud	Yes	Yes	Pass
8	Lignosulfonate Freshwater Mud	Yes	Yes	Pass
2-01	Spiked with 1% by volume mineral oil	Yes	Yes	Pass
2-05	Spiked with 5% by volume mineral oil	Yes	Yes	Pass
2-10	Spiked with 10% by volume mineral oil	Yes	Yes	Pass
8-01	Spiked with 1% by volume mineral oil	Yes	Yes	Pass
8-05	Spiked with 5% by volume mineral oil	Yes	Yes	Pass
8-10	Spiked with 10% by volume mineral oil	Yes	Yes	Pass
	Additional Muds			
008-0-0	Generic Mud # 8 Unspiked	No	Yes	Pass
008-0-.075	Spiked with 0% mineral oil; 0.075 ppbbl emulsifier	No	Yes	Fail
008-0-.15	Spiked with 0% mineral oil; 0.15 ppbbl emulsifier	No	Yes	Fail
008-0-.3	Spiked with 0% mineral oil; 0.3 ppbbl emulsifier	No	Yes	Fail
008-1-0	Spiked with 1% mineral oil; no emulsifier	No	Yes	Pass
008-1-.075	Spiked with 1% mineral oil; 0.075 ppbbl emulsifier	No	Yes	Fail
008-1-.15	Spiked with 1% mineral oil; 0.15 ppbbl emulsifier	No	Yes	Fail
008-1-.3	Spiked with 1% mineral oil; 0.3 ppbbl emulsifier	No	Yes	Fail
008-5-0	Spiked with 5% mineral oil; no emulsifier	No	Yes	Pass
008-5-.075	Spiked with 5% mineral oil; 0.075 ppbbl emulsifier	No	Yes	Fail
008-5-.15	Spiked with 5% mineral oil; 0.15 ppbbl emulsifier	No	Yes	Fail
008-5-.3	Spiked with 5% mineral oil; 0.3 ppbbl emulsifier	No	Yes	Fail
008-10-0	Spiked with 10% mineral oil; no emulsifier	No	Yes	Pass
008-10-.075	Spiked with 10% mineral oil; 0.075 ppbbl emulsifier	No	Yes	Fail
008-10-.15	Spiked with 10% mineral oil; 0.15 ppbbl emulsifier	No	Yes	Fail
008-10-.3	Spiked with 10% mineral oil; 0.3 ppbbl emulsifier	No	Yes	Fail
2	Generic Mud # 2 Unspiked	No	Yes	Pass
2-01-HSD	Spiked with 1%, high sulfur content diesel	No	Yes	Pass
2-03-HSD	Spiked with 3%	No	Yes	Fail
2-05-HSD	Spiked with 5%	No	Yes	Fail
2-08-HSD	Spiked with 8%	No	Yes	Fail
2-01-LSD	Spiked with 1%, low sulfur content diesel	No	Yes	Pass
2-03-LSD	Spiked with 3%	No	Yes	Fail
2-05-LSD	Spiked with 5%	No	Yes	Fail
2-08-LSD	Spiked with 8%	No	Yes	Fail
8	Generic Mud #8 Unspiked	No	Yes	Pass
8-01-HSD	Spiked with 1%, high sulfur content diesel	No	Yes	Fail
8-03-HSD	Spiked with 3%	No	Yes	Fail
8-05-HSD	Spiked with 5%	No	Yes	Fail
8-08-HSD	Spiked with 8%	No	Yes	Fail
8-01-LSD	Spiked with 1%, low sulfur content diesel	No	Yes	Fail
8-03-LSD	Spiked with 3%	No	Yes	Fail
8-05-LSD	Spiked with 5%	No	Yes	Fail
8-08-LSD	Spiked with 8%	No	Yes	Fail
	Drill Cuttings			
1A	Before washing with Baroid Invelmol mineral oil	No	Yes	Fail
1B	After washing oil-based mud	No	Yes	Fail
2A	Before washing with Milchem Carbotec	No	Yes	Fail
2B	After washing oil-based mud	No	Yes	Fail
3A	Before washing Vermillion Mageobar Faze-Kleen mineral oil	No	Yes	Fail
3B	After washing oil-based mud	No	Yes	Fail

2.3 API/OOC Drilling Fluids Bioassay Statistics

The Offshore Operators Committee (OOC) submitted drilling fluid toxicity data collected in 1985 and 1986 from drilling projects in the Gulf of Mexico. The toxicity data was compiled from an API/OOC guidelines questionnaire on used mud composition and toxicity. The following information was gathered by the questionnaire: toxicity, mud type, mud composition, mud weight, and type of hydrocarbon added. Approximately 42 percent of the drilling fluids tested for toxicity were below (more toxic than) the 30,000 parts per million value.[6]

2.4 Offshore Operators Committee Spotting Fluid Survey

The industry submitted the results of a retrospective survey comparing the success rates of diesel and mineral oil pills in freeing stuck pipe. This project was conducted in 1986 by the Offshore Operators Committee (OOC) and evaluated data from 1983 to 1986.[7]

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

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

Of 2,287 wells drilled with water-based muds, 506 stuck pipe incidents were identified in which the operator chose to use an oil additive to free the stuck pipe. Of the 506 incidents, 298 (or 59%) were treated with a diesel pill, while 208 (41%) were treated with a mineral pill. For some operators, mineral oil was the material of choice. Three operators (out of 16) used mineral oil pills exclusively. Diesel oil pills were successful 52.7 percent of the time and mineral oil pills were successful 32.7 percent of the time in freeing stuck pipe.

The OOC also examined mud and formation characteristics as factors in successful pill addition. These factors include: base oil type, time expired before spotting, depth of spot, and type of well (straight or deviated). Results indicated that reducing the length of time until the spot was applied improved the chance of success dramatically for diesel pills. A similar but less dramatic trend was observed for mineral oil pills. The diesel oil success rate was 61 percent if the pill was spotted in less than 5 hours. The rate dropped to 41 percent if the time until spot exceeded 10 hours. The mineral oil success rate was 35 percent if the pill was spotted in less than 5 hours; the rate dropped to 31 percent if the time until the spot exceeded 10 hours.

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

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

Some of the operators with extensive mineral pill experience achieved extremely high success rates, which were comparable to the highest diesel pill success rates. The three highest success rates among operators using mineral pills were 50, 60, and 75 percent. The highest success rates among operators using diesel pills were 60 and 64 percent.

2.5 THE EPA/API DIESEL PILL MONITORING PROGRAM

The Diesel Pill Monitoring Program (DPMP) was a jointly funded effort by EPA's Industrial Technology Division (currently Engineering and Analysis Division), the American Petroleum Institute, and Gulf of Mexico operators to investigate the practice of recovering diesel pills. The program involved the collection and analysis of samples from active mud systems prior to use and after removal of diesel pills. The primary purpose of the DPMP was to provide a mechanism to collect data for consideration in developing waste discharge regulations for the offshore oil and gas industry. The Gulf of Mexico was selected for this study because of the large number and diversity of drilling operations in this region.[8]

The program was implemented as part of EPA Region IV and VI's Final NPDES General Permit for the Outer Continental Shelf (OCS) of the Gulf of Mexico (U.S. EPA Permit No. GMG 280000, 1986, 51 *FR* 24897) that became effective on July 2, 1986. The DPMP was effective for one year under the general permit and was extended until September 30, 1987 by a *Federal Register* Notice dated July 6, 1987 (52 *FR* 25303). The permit implemented the DPMP which prohibited the discharge of mud to which diesel was added unless: (1) The diesel was added as a pill in an attempt to free stuck pipe, (2) The diesel pill and at least 50 barrels of drilling fluid on either side were removed from the active drilling fluid system and not discharged to the waters, and (3) Samples of the drilling fluid after pill removal and other additional data were provided to EPA in accordance with the Diesel Pill Monitoring program.

The participating drilling operators were required to conduct sampling activities with prepackaged sampling kits whenever a diesel pill was used to free stuck pipe. Samples were taken of the pill, the diesel oil used to formulate the pill, and the active mud systems before spotting and after the pill was recovered. Compliance with the permit's end-of-well toxicity limitation is demonstrated by analyzing the mud samples taken just prior to the introduction of the pill.

The mud and pill samples were tested by standard API RP 13B procedures for rheology, pH, and oil and water content by 10 ml retort. Diesel was determined by gas chromatography (GC) using the method described in the DPMP Program Manual. Drilling fluid bioassay tests were conducted according to The Drilling Fluids Toxicity Test described in the 1985 proposal (50 *FR* 34592). The toxicity test is determined on the suspended particulate phase by exposure of *Mysidopsis bahia* to the phase for 96 hours. EPA collected additional data on the levels of priority pollutant organics, metals, and conventional pollutants in some sampled muds.

During the period that the DPMP was in effect, 105 sampling kits were submitted to the program, representing 105 pills spotted in 56 wells. Three sets of data evolved from this program. Dataset 1 was used for examining relation-ships between diesel concentration and toxicity and between analytical methods used to measure total oil content and diesel content. Dataset 2 was used in calculating success rates for freeing stuck pipe. Dataset 3 was used in determining correlations with diesel recovery levels.

Diesel oil recovery was determined from the difference between the amount of diesel oil added to the mud system and the amount of diesel oil remaining in the active system after two complete circulations of the mud system following pill recovery. Diesel recovery varies with the volume of the "extra buffer" captured. Extra buffer refers to the amount of drilling fluid in excess of the buffer volume required by the DPMP; which is 100 barrels, 50 barrels on each side of the pill. As shown in Table V-3, the diesel recovery for the overall program ranged from 4.2 to 100 percent. The mean recovery level was 76.5 percent while the median recovery level was 83 percent. Increasing buffer volume had little or no effect on the mean, median, or maximum recoveries, however, it did increase the minimum recovery level of the pill (from 32.1 to 72.9 percent over the entire extra buffer interval).

TABLE V-3

PERCENT DIESEL RECOVERED VS QUANTITY OF EXTRA BUFFER* HAULED ASHORE FOR DISPOSAL[8]

Extra Buffer (BBLS)	Number of Incidents	% Percent Diesel Recovered			
		Mean	Median	Minimum	Maximum
0'	11	73.4	77.1	32.1	96.0
0 < BBLS < 100	18	75.0	87.8	4.2	100.0
100 < BBLS < 200	10	78.0	83.9	44.1	96.2
200 < BBLS < 300	13	77.3	82.3	24.0**	97.9
BBLS $\geq$ 300	6	82.8	79.5	72.9	98.0
Totals	58	76.5	83.0	4.2	100.0

*Volume of extra buffer hauled ashore is equal to: Volume Hauled - Volume Spotted - 100 barrels
**Next lowest value is 61.4.

Mud toxicity varies with diesel content. At low diesel concentrations, mud LC50 values decrease rapidly with increasing diesel content. At higher diesel concentrations, mud LC50 values decrease gradually. Most of the muds sampled before spotting had LC50 values higher than those sampled after spotting (the median LC50 values of the mud samples before and after spotting were 52,000 ppm and 6,000 ppm respectively). The mud samples with low LC50 values before spotting represent muds which already contained diesel or mineral oil. In most cases, these mud samples were obtained before spotting a second or third pill, after the first or second pill had already been spotted. Thus, mud toxicity is observed to be a strong function of diesel content, especially at low diesel concentrations.

Water-based muds may be broadly classified as either clay muds (those that depend on clay for viscosity) or polymer muds (those that depend on a polymer for viscosity). To examine the effect of diesel on the toxicity of these two mud types, the DPMP muds were classified as clay or polymer muds. At very low diesel oil concentrations the mean LC50 values for both basic mud types are greater than 400,000 ppm. Mean LC50 values for both mud types decrease similarly with increasing diesel oil content. Thus, it appears that toxicity related to the presence of diesel oil is not a function of mud type.

The overall rate of success for freeing stuck pipe was 40.0 percent (first pill per sticking incident). This determination is based on 28 successes in 70 incidents. Six of the incidents involved stuck casing rather than stuck drill pipe. The casing was not successfully freed in any of these incidents. The success rate for freeing stuck drill pipe was 43.8 percent (28 successes in 64 incidents).

Good practice involves spotting a pill equal in density to the mud density for well control and to prevent gravity migration of the pill away from the interval where the drill pipe is stuck. Generally, the pill density was closely matched to the mud density for each of the sticking incidents in this program. To examine the effect of density on success rate, the incidents in Dataset 2 were divided into two groups based on pill density. Approximately half of the incidents in Dataset 2 had pill densities less than 12.0 pounds per gallon (ppg) and the other half had pill densities greater than 12.0 ppg. The success rate for those cases where the pill density was less than 12 ppg was 62.5 percent, while the success rate for those cases where the pill density exceeded 12 ppg was only 21 percent.

Based on analyses of information generated during the DPMP, EPA concluded that use of the pill recovery techniques implemented during this program do not result in recovery of sufficient amounts of the diesel pill or reduction of mud toxicity to acceptable levels for discharge of bulk mud systems. Mud systems for approximately one-half of all wells in the DPMP contained residual diesel levels between 1 and 5 percent (by weight) after introduction of a diesel pill and subsequent pill recovery efforts. In addition, mud systems for approximately 80 percent of the DPMP wells failed the 30,000 ppm LC50 limitation after pill recovery. Forty percent of the DPMP wells using water-based mud systems that contained residual diesel oil following pill recovery showed LC50 values of less than (more toxic than) 5,000 ppm.

2.6 STATISTICAL ANALYSIS OF THE API-USEPA METALS DATABASE

The API-USEPA metals database is a compilation of 24 datasets containing information on metals concentrations in barite, drilling fluids, drill cuttings, and formation sediments. The dataset includes data collected by industry, and state and federal regulatory agencies. EPA determined each of the dataset's suitability for use in a statistical analysis through evaluation of: the sampling design, the pertinent materials sampled, and the precision and accuracy of the physical and chemical methods used. EPA identified seven of the 24 datasets that were suitable for analysis in determining the metals characteristics in barite, drilling fluids, and drill cuttings. EPA used the following datasets in its statistical analysis: *the Fifteen Rig Study, Discharge Monitoring Report Data from Region 9, Discharge Monitoring Report Data from Region 10, Determination of Mercury and Cadmium in Drilling Fluids and Cuttings, Determination of Mercury, Cadmium and Density in Drilling Fluids and Barites, and the Diesel Pill Monitoring Program - Report #5*.[9,35]

Data from the seven datasets were used to statistically determine the following:

- The distributional assessments of cadmium and mercury concentrations in barite, drilling fluids, and drill cuttings.
- The contribution of the geological formations to cadmium and mercury concentrations in drill cuttings.
- The correlation of cadmium and mercury concentrations with the other metals in barite and drilling fluids.
- A descriptive statistics for metals concentration in commercially available drilling fluids.

The statistical analysis was primarily descriptive, however, three specific conclusions can be drawn from the analysis. The first two conclusions pertain to the hypothesis of an increase in cadmium and mercury due to formation contributions and the third conclusion pertains to the correlation of cadmium and mercury with other metals in barite and drilling fluids. The conclusions are as follows:

1) The hypothesis of an increase in mercury concentrations in drill cuttings due to the geological formation is not supported from the two sets of data used in this analysis.

2) The hypothesis of an increase in cadmium concentrations in drill cuttings was supported by the statistical analysis of one dataset, but the analysis of the second relevant dataset was inconclusive.

3) In general, there is a positive correlation between the concentrations of cadmium and mercury and concentrations of other metals found in barite and drilling fluids.

2.7 STUDY OF ONSHORE DISPOSAL FACILITIES FOR DRILLING WASTE

In 1987, EPA conducted a survey of onshore waste disposal facilities available for disposal of drilling fluids and drill cuttings generated from offshore oil drilling operations.[10] The focus of the survey was to:

- Investigate waste treatment methods available for treating drilling fluids and drill cuttings to render them acceptable for disposal.
- Investigate waste disposal facilities used for drilling fluids and drill cuttings such as landfill, land treatment, deep well injection, etc.
- Determine the available and projected future capacity of the waste disposal facilities surveyed and estimate the total required capacity for the disposal of drilling fluids and drill cuttings from offshore drilling operations.
- Estimate waste treatment and disposal costs.

Information regarding the method of waste treatment and disposal was obtained from 16 operating companies with disposal facilities in California, Louisiana, and Texas.

A variety of treatment and disposal systems were employed by the companies surveyed; ranging from disposal of contaminated drilling fluids with and without treatment to treatment of the fluids and transferral of the treated material to another facility for final disposal. The typical methods of disposal were: landfills, land treatment, deep well injection, and mud reclamation. This study is discussed further in Section VII.5.2.4.

2.8 ONSHORE DISPOSAL OF OFFSHORE DRILLING WASTE - CAPACITY OF ONSHORE DISPOSAL FACILITIES

This study evaluated the permitted capacities of onshore disposal facilities that accept offshore drilling wastes and whether these facilities had adequate capacity to dispose of projected waste volumes. The initial survey was conducted in 1989 and is documented in "Onshore Disposal of Drilling Waste: Capacity and Cost of Onshore Disposal Facilities," prepared for EPA by ERCE, March 1991.[11] The evaluation focused on the three major geographic areas where onshore disposal of offshore drilling waste would be encountered: the Gulf of Mexico, California, and Alaska. In each area, the capacity to accept and properly dispose of the drilling waste was evaluated based on assumptions regarding the level of drilling activity, volumes of drilling waste per well-site, and onshore disposal volumes. Treatment and disposal options for offshore waste disposal in each region were evaluated based on telephone contacts with knowledgeable individuals associated with state/local regulatory agencies or with disposal facilities. Estimates of regional capacity were derived from telephone contacts with facility operators, recently completed state hazardous waste Capacity Assurance Plans, state data on nonhazardous waste facilities, and literature sources.

The survey conducted in 1989 estimated the projected available capacity for drill waste by reviewing permitted capacity and projections of future permitted capacity. At that time, data on the degree to which disposal capacity was used were not available. In 1992, updated estimates of capacities were made using currently permitted volumes and data on the volumes of wastes treated at the disposal sites were obtained to derive more accurate projections of the "excess" available capacity.[12,13]

Section XVIII.2.2 presents a detailed discussion on the original survey (1989 survey) and the 1992 update survey on the available existing and projected future landfill capacity as it pertains to the offshore oil and gas industry.

2.9 OFFSHORE DRILLING SAFETY

In 1992, EPA evaluated data associated with personnel casualties that occurred on mobile offshore drilling units (MODUs) and offshore supply vessels (OSV) for the years 1981 through 1990. The personnel casualty data was compiled from the U.S. Coast Guard's Personnel Casualty file (PCAS). The study focused on accidents related to the handling and transportation of material, since this would be most similar to the additional activities required should a zero discharge limitation be imposed.[14, 15]

Sections XVIII.2.4.2 presents a detailed discussion on the findings of the EPA's evaluation of safety as it relates to drilling activity and increased offshore supply vessel activity due to zero discharge requirements on drilling waste.

3.0 PRODUCED WATER DATA GATHERING

3.1 INTRODUCTION

EPA's initial effort to investigate priority pollutants in produced water consisted of a preliminary screening survey conducted at six production platforms in the Gulf of Mexico during 1980. Results obtained by using the standard procedures being proposed by EPA at that time indicated the presence of toxic organics and metals. The results were questioned by industry because the analytical methods used had not been validated for water with high dissolved salt content which is common for produced water.

In 1981, EPA collected produced water effluent samples from 10 platforms in the Gulf of Mexico. The objectives of the study were to: characterize the produced water with respect to oil content, identify the factors contributing to the oil content in produced water, and evaluate approaches to reduce the oil content in produced water effluents. The study included platforms with three types of gravity separators and nine of ten platforms had gas flotation treatment. The study characterized the removal efficiency of oils from produced water using the following criteria: oil and grease analysis, susceptibility-to-separation test, suspended solids test, crude oil equilibrium, particle-size distribution, and operational characteristics consisting of well and process data.[16]

3.2 30 PLATFORM STUDY

In 1981, EPA and OOC coordinated efforts to develop and implement a sampling program to characterize the priority pollutants in produced water effluents. This sampling effort is known as the "30 platform study." The 30 platform study consisted of two phases; the development of analytical protocols for quantifying priority pollutants in produced water, and the sampling and analysis of produced water effluents.

In Phase I, produced water samples were collected from two production platforms in the Gulf of Mexico and sent to ten EPA and industry laboratories for comparative testing. Analytical efforts were conducted to determine: (1) the precision and accuracy, (2) the level of detectability, and (3) the level of quantification of the proposed methods on produced water samples. Final analytical protocols were established employing: standards purged from 10 percent sodium chloride brines, isotope dilution gas chromatography/mass spectrometry (GCMS) for analysis of volatile organic pollutants, continuous and/or acid/neutral extraction and fused silica capillary column isotope dilution GCMS for analysis of semivolatile organic pollutants, and standard addition flame atomic absorption for metal analysis.[17]

Phase II of the analytical program was conducted to confirm the presence and quantify the concentrations of toxic pollutants in produced water discharges from 30 production facilities in the Gulf of Mexico using the established protocols.[18] Selection of the thirty platforms was based on the following criteria: production rate, water cut, hydraulic loading, operating companies, and geographical distribution. Twenty-five of thirty platforms utilized gas floatation technology.

Pollutants analyzed were: the priority organics, chloride, iron, oil and grease (O&G), total dissolved solids (TDS), and certain metals, namely cadmium (Cd), chromium (Cr), copper (Cu), lead (Pb), nickel (Ni), silver (Ag), and zinc (Zn).

The sampling program was designed to include an evaluation of the major components of variability which include: (1) Analytical variability, (2) Intra-platform variability, and (3) Inter-platform variability. To evaluate these components of variability, several platforms were sampled for consecutive days and more than once per day. A description of the types and numbers of samples taken is as follows:

Number of Platforms	Sample Type	Number of Samples
16	1 Day Effluent	16
7	1 Day Influent/Effluent	14
4	2 Day Influent/Effluent	16
3	3 Day Influent/Effluent	18
30		64

In addition, 10 duplicate effluent and 5 duplicate influent samples were collected which results in a total of 79 samples collected for the sampling program. Tables A2-1, A2-2, and A2-3 in Appendix 2 present analytical data from this study.

3.3 ALASKA AND CALIFORNIA SAMPLING PROGRAMS

In 1982, priority pollutant sampling efforts were conducted at Alaska and California sites. Produced water samples were collected from coastal and onshore treatment facilities in Cook Inlet and Prudhoe Bay, Alaska and from three offshore production platforms in California's Santa Barbara Channel. Data obtained from these sampling efforts are presented in the report entitled *Priority Pollutants In Offshore Produced Oil Brines*.[19]

3.4 PRODUCED WATER TREATMENT TECHNOLOGY EVALUATIONS

Since the 1985 proposal, EPA evaluated additional technologies for consideration as add-on technologies to BPT technology and better performance of gas flotation, one of the BPT technology bases. The add-on technologies evaluated by EPA were multi media filtration and crossflow membrane filtration. EPA also evaluated the technical feasibilities of produced water reinjection in offshore regions. This section details the EPA's evaluations for these produced water treatment technologies.

3.4.1 Three Facility Study

In June of 1989, EPA conducted a comprehensive 4-day sampling program at three oil and gas production facilities to evaluate the performance of granular filtration technology and to characterize produced water and other miscellaneous discharges such as produced sand, well treatment fluids and deck drainage. The study also evaluated two different analytical methods for measuring oil and grease. Oil and grease content was determined using an analytical method that measures the total oil and grease, consisting of certain soluble and insoluble compounds using freon as an extraction solvent, and another analytical method that only measures the insoluble compounds contained in oil and grease. EPA selected facilities for the three facility study based on: (1) their use of granular filtration, and (2) the oil and grease level being comparable to the BPT level prior to filtration. The facilities selected were not all in the offshore subcategory because granular filtration is not in widespread use on offshore platforms. The only operating granular filtration unit on a platform was located offshore California. The three facilities selected for this study were: Thums Long Beach Island Grissom (coastal subcategory), Shell Western, E & P, Inc. - Beta Complex (offshore subcategory), and Conoco's Maljamar Oil Field (onshore subcategory).[20,21,22]

The three facility study collected operating and analytical data from each of the granular filtration units. The filter influent, effluent, and backwash streams were analyzed for oil and grease, total suspended solids, and radionuclides. The study also evaluated the wastes associated with the backwash cycle and the potential of accumulation and/or concentration of radionuclides in the backwash stream. In addition to sampling, granular filtration system design parameters, such as space requirements, maintenance requirements, and capital and annual costs were collected.

Analytical data and a discussion of the results of the three facility study are presented in Section IX.4 and in Table A2-4 in Appendix 2.

3.4.2 Ceramic Crossflow Membrane Filtration

EPA conducted a week-long study at a production platform in the Gulf of Mexico that operates the only full-scale ceramic membrane filtration unit treating oilfield produced water in the United States. The membrane study, conducted April 3 through April 10, 1991, consisted of a seven day sampling period and sampled all of the major streams around the unit. The streams sampled were: influent, effluent (permeate), recycle (retenate), solids blowdown, oil float, and the acid wash. The analytes examined for each of these streams are as follows: oil and grease (EPA Methods 413.1 (total) and M413.1 (soluble)), total petroleum hydrocarbons, metals, volatile organic analysis, extractable organics, radionuclides (radium 226, radium 228, and gross alpha and beta), and total suspended solids.[23]

The unit studied has a design rated capacity of 5,000 barrels per day and is processing a portion (slip stream) of the BPT produced water stream for pretreatment prior to waterflood. The membrane filters consist of two ceramic membrane modules operating in parallel. The membranes have an absolute pore size of 0.8 microns. The complete filtration system consists of the following equipment: filtration modules, feed tank, backpulse tank, feed pump, backpulse pump, chemical feed system, and chemical wash system. The system is skid mounted and occupies a total area of four hundred square feet.

Analytical data and a discussion of the results of the membrane study are presented in Section IX.5.2.4.

3.4.3 Evaluation of Gas Flotation Performance

EPA received gas flotation operating data from industry and conducted a literature search on the operating characteristics of gas flotation units.

In 1991, as comments to the proposed rule, API submitted information on produced water effluents that were from systems considered operating with improved performance. EPA's evaluation of this data included a statistical analysis.[24] Results of the statistical analysis are presented in the report entitled "Analysis of Oil and Grease Data Associated with Treatment of Produced Water by Gas Flotation."

In 1992, EPA conducted a literature search on the operating characteristics of gas flotation technology used for separation of oil from produced water. The literature search identified approximately ten useful documents detailing the operating characteristics of gas flotation technology.[25] The results of the literature search are contained in the report entitled "Oil/Water Separation by Gas Flotation."

3.4.4 Technical Feasibility of Brine Reinjection

The technical feasibility of offshore reinjection of produced water was evaluated to determine any technical limitations that would preclude reinjection as a basis for zero discharge of produced water.[26] Data on the geology of the Atlantic, Gulf and Pacific Coasts were collected from published sources and direct communications with U.S. Geological Survey personnel knowledgeable of the offshore regions subsurface geology. The offshore regions were evaluated for their sedimentological and tectonic history to determine if suitable formations and conditions are available for disposal operations. Information was also collected from onshore and coastal brine disposal operations. Also, state and federal regulatory agencies in the oil producing states were contacted to obtain information on disposal operations practiced in their respective areas of responsibility. The evaluation included the following findings:

- In general and except for the technical situations outlined below, brine reinjection, in the coastal and offshore areas, as a form of pollution control is technologically feasible in all coastal and offshore areas of the United States. The geology of these areas indicates the presence of formations with properties that make them suitable for disposal reservoirs. However, some areas along the Pacific coast are under stress and geologically active. These areas will be rather site specific and reinjection in these areas will require careful evaluation.

- Most decisions to reinject or not reinject formation fluids are based more on economic considerations than on technical reasons. California oil and gas operators actively reinject because the oil is very viscous and waterflooding is necessary to obtain maximum recovery. The capital investment in equipment thus has a definitive financial return. In other coastal areas, oil viscosity is not a major problem and reinjection into producing formations may cause loss of production. Reinjection in those areas would be specifically for disposal in non-producing formations.

- Technical exceptions from reinjection may be necessary for some limited and special situations. Potential reasons for considering a technical exception are: possible contamination of underground sources of drinking water, potential seismic activity in areas of known active faults, solution of in situ salt formations, and areas where the geology is not detailed enough to a make a reasonable determination as to where injected water may eventually migrate.

3.5 LITERATURE DATA COLLECTION FOR RADIOACTIVITY IN PRODUCED WATER

In 1992, EPA reviewed data presented in literature on the presence of radium in produced water generated from onshore, coastal, and offshore production activities. The information and data obtained is presented in the following two reports: *Presence of Radium in the Gulf of Mexico*[27] and *Summary of Produced Water Radioactivity Studies*.[28]

4.0 DATA COLLECTION FOR MISCELLANEOUS AND MINOR DISCHARGES

Previous data collections relating to miscellaneous and minor waste streams have been sporadic in the numerous studies of offshore oil and gas discharges. EPA therefore conduced a study to review the available information relating to minor wastes and summarize the characteristics, handling practices, treatment technologies and costs for each type of waste.[29] Minor waste streams investigated include all point sources originating from offshore oil and/or gas drilling rigs or production platforms other than produced water, drill cuttings, or drilling fluids.

Information was compiled from the following sources:

- The offshore, coastal, and onshore rulemaking record.
- Telephone conversations with Region VI, IX, and X personnel.
- Various discharge monitoring reports submitted to Region X on behalf of dischargers in Cook Inlet, Alaska.
- DMR reports for Regions VI, IX, and X.
- Various EPA and API reports/publications.

5.0 ANALYTICAL METHODS

5.1 REVIEW OF STATIC SHEEN TESTING PROCEDURES

Since the proposal of the static sheen test in 1985, several variations to the method proposed in 1985 have been suggested. EPA has reviewed three other methods: one developed by Region IX, one by Region X, and an additional version known as the "minimal volume" method. A comparison of the differences between protocol of the 1985 proposal and the Region IX suggested methods is presented below:

- Receiving water - The procedures proposed in 1985 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 procedure proposed in 1985 calls 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." In their procedures, Region IX expresses concerns over test interferences due to bubbling/foaming and particulate surface deposits. This appears to be the reason Region IX discourages mixing or stirring activities.

- Sample volumes/weights - The procedures proposed in 1985 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 g (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 procedure proposed in 1985 requires 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 1985 proposed method. 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 employed by Region X is similar to the 1985 proposed method except that a free oil determination is based on the appearance of a sheen on more than one-half of the water surface, as per the Region IX method.

The "minimal volume" test procedure requires a sample volume of 5 ml or weight of 15 g. The receiving water is tap water. Stirring should be minimized (although not specified). Observations are made within 5 minutes. The presence of free oil is determined by criteria similar to the 1985 proposal. This procedure was developed in an attempt to produce better results with less variability under laboratory conditions.

A study was performed by industry which compared these static sheen methods.[30] 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 positive results gives an indication of the reliability of the test. The 1985 proposed method, also the same method used by Region IX at the time of the study, showed 16.76 percent false positives. The Region X method showed 2.5 percent and the minimal volume method showed 21.86 percent false positives.

In 1989, EPA conducted an additional study solely on the minimal volume test.[31] Twenty-six individuals made observations on 56 muds samples at EPA's Gulf Breeze Laboratory. The results of this evaluation were that for muds without oil, 6.0 percent false positives were recorded. The study revealed that false negatives were more likely to occur if mineral oil was present in the sample as opposed to diesel oil.

5.2 Analytical Method for Diesel Oil Detection

The August 26, 1985 *Federal Register* notice proposed a method for detecting the presence of diesel oil in drilling fluids and drill cuttings waste streams. The method, based on retort distillation and gas chromatography, was subsequently modified based on experience gained during the Diesel Pill Monitoring Program. The revised version of Proposed Method 1651, "Oil Content and Diesel Oil in Drilling Muds and Drill Cuttings by Retort Gravimetry and GCFID" appeared in Appendix A of the 1988 *Federal Register* Notice of Availability. However, this version was incomplete and later correctly published in a 1989 *Federal Register* Notice (54 *FR* 634).

In the March 13, 1991 proposal notice (56 *FR* 10676), EPA identified the EPA Method 1651 as adequate for use in identifying the presence of diesel oil. However, work was continued on alternative extraction and analysis techniques to simplify the operational portions of the method and enable better identification of diesel oil in the presence of interferences. As a result, EPA has developed test methods for the measurement of the hydrocarbons normally found in oil, including the polynuclear aromatic hydrocarbon (PAH) content of the oil. Combined, these techniques can be used to discern diesel oil in the presence of other components likely to be found in drilling wastes. This section gives a brief history of the efforts to develop test methods for the determination of diesel oil in drilling fluids and drill cuttings and a description of test methods that have been developed to measure and differentiate diesel oil, mineral oil, and crude oil.

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

Extraction techniques included ultrasonic, Soxhlet/Dean-Stark, and supercritical fluid. Determinative techniques included high performance liquid chromatography with ultraviolet detection

(HPLC/UV), and gas chromatography with flame ionization detection (GC/FID). One device combined extraction and determination. In this device, the drilling waste sample was placed in a small chamber and heated rapidly to desorb the oil into a flowing gas stream. The components of oil entrained in the gas stream were separated by gas chromatography, and detection by flame ionization.

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

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

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

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

In this next phase, the PAH content of the oil in the drilling waste is determined using the HPLC/UV Method. If the PAH content is less than that attributable to mineral oil, the mud may be discharged; if greater than that attributable to mineral oil, the oil could be either diesel or crude oil. To determine whether the oil is diesel or crude, the absence of n-alkanes in the diesel range or the percent of C25 - C30 alkanes using the GC/FID Method must be used to show that the oil was crude oil from the formation. If the oil was crude oil, the mud may be discharged providing it meets the other discharge limitations of the rule.[32]

5.3 Oil and Grease

Two analytical methods for oil and grease have been investigated by EPA: Standard Method 503A, also known as EPA Method 413.1 which is based on a freon extraction and is referred to as the "gravimetric" method; and Standard Method 503E, known as EPA Method M413.1 and referred to as the "silica gel" method.

Standard Method 503A is designed to extract dissolved or emulsified oil and grease from water using trichlorotrifluoroethane (freon). This method measures total (soluble and insoluble) oil and grease. Special precautions regarding temperature and solvent vapor displacement are included in the procedure to minimize the oxidation of certain extractables. This method, measuring total (freon extractable) oil and grease was used in developing the limitations for BPT, and this method is incorporated in the NPDES discharge permits.

Standard Method 503E utilizes silica gel to extract polar materials, such as fatty acids, from the sample before the extraction with freon. This method measures only a portion of the total oil and grease. The materials not removed by the silica gel are designated as soluble hydrocarbons. Standard method 503E may be performed immediately after Standard Method 503A by re-solubilizing the weighed residue of Standard Method 503A in freon and treating with silica gel.

In the three facility study, analytical results from both methods were compared. Each produced water sample taken was analyzed using Standard Method 503A while Standard Method 503E was utilized on alternating samples. This allowed direct comparison of both methods on half of the samples collected at each facility. Results of this comparative analysis showed values reported by the silica gel method to be consistently lower than the gravimetric method, as expected.

5.4 Drilling Fluids Toxicity Test

Final BAT and NSPS regulations include a limitation on the toxicity of discharged drilling fluids and drill cuttings. 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, also called mysid shrimp. In 1985, EPA proposed a toxicity limitation of 30,000 ppm based on the toxicity of the most toxic of eight generic drilling fluids that were in general use at the time of the proposal. Since 1985, permit writers have set this limit as their best professional judgment of BAT, and it is currently included in the general permits for oil and gas activities in the outer continental shelf of the Gulf of Mexico and offshore of California and Alaska.

In 1991, EPA conducted a two phase study on the variation in results from the toxicity test for drilling fluids 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 proposal.[33,34,36,37]

In Phase I, each lab was required to conduct one toxicity test on a sub-sample of generic drilling fluid Number 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. At the time, the Agency knew of over 100 commercial, academic, and industry labs that were potentially capable of conducting the required test.

In Phase II, each selected lab was required to conduct two toxicity tests on sub-samples of generic drilling fluid Number 8 (lignosulfonate freshwater mud) and two toxicity tests on sub-samples of generic drilling fluid Number 8 with 3 percent mineral oil. A total of 12 labs were selected at random from those Phase I labs that demonstrated the ability to conduct the toxicity test at a competitive price. However, one of the labs selected for Phase II failed to complete the study.

A summary of the results for the 9 contract labs which completed the Phase II portion of the study is presented in Table V-4. The results shown for the "selected" labs in the summary for generic fluid Number 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 whereas the other 12 labs (making up the total of 28 labs shown under the "all" category) did not completely follow the correct protocol. The primary summary statistics included in the table are the average toxicity (LC50), standard deviation (SD), predication intervals, and the coefficient of variation (CV).

The average LC50 was slightly higher (less toxic) than expected for the sample of generic drilling fluid Number 3 and for the sample of generic drilling fluid Number 8. However, the average LC50

TABLE V-4

SUMMARY OF RESULTS FOR THE VARIABILITY STUDY[36]

Drilling Fluid	Number of Contract Labs	Average LC50 (% spp)	Standard Deviation	Coefficient of Variation (%)
Combined Within and Between Lab Variation				
Generic #3	28	25.6	12.0	47.1
Generic #3[a]	16	22.6	6.0	26.4
Generic #8	9[b]	46.9	19.3	41.2
Generic #8 with 3% Oil	9[b]	0.33	0.46	139.7
Between Lab Variation				
Generic #8	9[b]	46.9	16.3	34.8
Generic #8 with 3% Oil	9[b]	0.33	0.33	100.0
Within Lab Variation				
Generic #8	9[b]	46.9	10.3	22.0
Generic #8 with 3% Oil	9[b]	0.33	0.32	96.6

[a] "Well performing" contract labs
[b] Two contract labs had non-estimable LC50 values

Notes:

1) All LC50s were calculated using Probit Analysis by Maximum Likelihood and with optimization for control mortality.
2) Average LC50 is the average of the average LC50 for each lab.
3) Standard Deviation (SD) for combined within and between lab variation is the square root for the sum of the within and between lab variances estimates.
4) Coefficient of Variation (CV) is equal to (SD)/(Average LC50)x100%.

reported for generic drilling fluid Number 8 with 3 percent mineral oil was lower (more toxic) than expected. It is important to note that each of these average lab results is based on each lab testing 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.

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 deviation (SD) reported in Table V-4 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 Number 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 EPA is primarily interested in estimates of within lab variation so these estimates are presented for generic drilling fluid Number 8 and generic drilling fluid Number 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, for the most part, is caused by inconsistent lab practices and thus it can be modified through learning from experience.

Coefficients of variation (CV) indicate how much, on a percentage basis, the LC50 could vary within a single standard deviation. The CVs presented in Table V-4 are useful for comparison with lab variation CVs estimated for other mysid toxicity tests, such as the American Petroleum Institute's mysid toxicity test for drilling fluids, on materials of equal toxicity. Since the CV is calculated by dividing the estimated standard deviation by the average LC50, it is important to realize that a large CV can occur due to an average LC50 that seems small or an estimated standard deviation that seems large. That is why lab CVs should only be compared between samples of equal toxicity. In the case of this lab variability study, the average LC50s seem to decrease, with increased toxicity, more rapidly than the estimated standard deviations decrease. Hence, the CV appears to increase as the absolute variation, measured by the standard deviation, decreases. However, since only three drilling fluids were tested by appropriately selected labs, the basis for concluding that a trend exists is weak.

Analysis of the multi-lab results for toxicity tests from this study continue to support the conclusion that results from EPA's toxicity test for drilling fluids are reproducible in the sense that test results for a single fluid appear to vary about an average toxicity. As the test is reproducible, it is adequate for use in a regulatory framework.

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SECTION VI

SELECTION OF POLLUTANT PARAMETERS

1.0 INTRODUCTION

This section of the document presents information concerning the selection of the pollutant limitations for the Final Offshore Oil and Gas Extraction Effluent Limitations Guidelines and Standards. The information consists of identifying the pollutants for which limitations and standards are set and discussions of the pollutants controlled by the "indicator" pollutants that have limitations in the rule and pollutants not specifically limited in the rule.

The section identifies and discusses the pollutant by wastestream.

2.0 DRILLING FLUIDS AND DRILL CUTTINGS

In the Offshore Oil and Gas Effluent Guidelines and Standards, EPA is controlling pollutants found in drilling fluids and drill cuttings as follows: zero discharge of drilling fluids and drill cuttings within three miles from shore; and for discharge of drilling fluids and drill cuttings at distances greater than three miles from shore: a prohibition on the discharge of diesel oil, a prohibition on the discharge of free oil, limitations on the toxicity of the drilling fluids and drill cuttings, and limitations on mercury and cadmium in stock barite. These limitations represent the appropriate level of control under BAT, BCT and NSPS for these indicators and the constituents they control.

The specific conventional, toxic and nonconventional pollutants found to be present and their concentrations in drilling fluids and drill cuttings, including compositions with diesel and mineral oils added, are summarized in Table VII-5, "Pollutant Analysis of Generic Drilling Fluids," Table VII-6, "Organic Pollutants Detected in Generic Drilling Fluids, Table VII-7, "Metal Concentrations in Generic Drilling Fluids," and Table VII-9, "Organic Constituents of Diesel and Mineral Oils." Toxic organic compounds and metals identified in these data summaries include naphthalene, phenanthrene, phenol, zinc, lead, chromium, and copper.

In addition, these data summaries include the conventional pollutants, BOD and oil and grease, along with nonconventional pollutants, including chemical oxygen demand (COD) and numerous alkylated phenols, benzenes, fluorenes and others. EPA has determined that it is not technically feasible to control specifically each of the toxic constituents of drilling fluids and drill cuttings that are controlled by the limits on diesel oil and free oil. The prohibitions on discharge of free oil and diesel oil contained in the rule (in addition to the zero discharge requirement within three miles) effectively remove these toxic pollutants from the discharges and reflect control at the BAT and NSPS levels. In addition, limitations on toxicity and cadmium and mercury content in barite control toxic and nonconventional pollutants in drilling fluids and drill cuttings waste discharges at the BAT and NSPS levels, as is set forth below. EPA has determined that it is not technically feasible to control specifically the toxic pollutants controlled by the mercury and cadmium limits.

Use of these limitations as indicators for the control of other specific constituents or for removing specific compounds is discussed further below.

2.1 DIESEL OIL

In the Offshore Guidelines, EPA is prohibiting the discharge of drilling fluids and drill cuttings containing diesel oil. Drilling fluids containing diesel oil contain a number of toxic and nonconventional pollutants as discussed above (also see Table VII-9). Diesel oil may contain from 20 to 60 percent by volume polynuclear aromatic hydrocarbons (PAHs) which constitute the more toxic components of petroleum products. Diesel oil also contains a number of nonconventional pollutants, including PAHs such as methylnaphthalene, methylphenanthrene, and other alkylated forms of the listed organic priority pollutants.

Prohibiting discharge of diesel oil, therefore, eliminates discharge of the above listed constituents of diesel oil. As shown in Table VII-6, the generic water-based drilling fluids with and without mineral oil contain substantially less biphenyl and phenanthrene (especially without mineral oil).

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

2.2 FREE OIL

In the Offshore Guidelines, EPA is also prohibiting the discharge of drilling fluids and drill cuttings containing free oil. The technology basis for this limitation is substitution of water-based fluids for oil-based fluids, non-petroleum oil containing additives and minimization of the use of mineral oil. An additional technology basis for compliance with the prohibition on the discharge of free oil is transporting the drilling wastes to shore for treatment and either disposal or reuse. Transporting the drilling wastes to land would be used instead of product substitution when crude oil contaminates the used drilling fluids due to the contribution of the oil from the formation being drilled. In these situations, toxic and nonconventional pollutants contained in crude oil are eliminated from discharge. Free oil is being regulated under BAT and NSPS as an "indicator" pollutant for the control of toxic pollutants. Free oil is being regulated under BCT as well. Although it is not a listed conventional pollutant, as is oil and grease, EPA is limiting free oil as a surrogate for oil and grease under BCT in recognition of the complex nature of the oils present in drilling fluids, including crude oil from the formation being drilled.

Free oil and diesel oil are both related to the concentration of toxic as well as conventional and nonconventional pollutants present in those oils. The pollutants "diesel oil" and "free oil" are considered to be "indicators" and to control, respectively, specific toxic pollutants present in the complex hydrocarbon mixtures used in drilling fluid systems. These pollutants include benzene, toluene, ethylbenzene, naphthalene, phenanthrene, and phenol.

Prohibiting discharge of free oil eliminates discharge of the above-listed constituents, to the extent that these constituents are present to a lesser degree in substitute fluids and additives. Prohibiting the discharge of free oil also reduces the level of oil and grease present in the discharged drilling fluids and drill cuttings.

2.3 TOXICITY

Acute toxicity is a measurement used to determine levels of pollutant concentrations which can cause lethal effects to a certain percentage of organisms exposed to the suspended particulate phase (SPP) of the drilling fluids and drill cuttings. As is the case with the other limitations for control of drilling fluids and drill cuttings, the technology basis for the toxicity limitation is product substitution, i.e., substitution of less toxic drilling fluids for the more toxic drilling fluids, or if the toxicity limitation cannot be met, transporting the drilling fluids and drill cuttings to shore for disposal. By limiting toxicity, operators use less toxic drilling fluids (basic compositions and additives), and the result is lower amounts of pollutants being discharged.

Additives such as oils and some of the numerous specialty additives, especially biocides, may greatly increase the toxicity of the drilling fluid and the drill cuttings due to the adherence of drilling fluid to the cuttings. The toxicity is, in part, caused by the presence and concentration of toxic pollutants. However, control of free oil and diesel oil, in some cases, is not an effective means of regulating these additives since they are not diesel oil nor do they contain constituents with a free oil component. A toxicity limitation requires that operators also must consider toxicity in selecting additives and select the less toxic alternatives. Thus, the toxicity limitation will also serve to reduce discharges of toxic and nonconventional pollutants. The limitation would encourage the use of the lowest toxicity generic water-based drilling fluids (see Section VII) or newer drilling fluid compositions with lower toxicity than the generic fluids, and the use of low-toxicity drilling fluid additives (i.e., product substitution).

Toxicity of drilling fluids and drill cuttings is being regulated as a nonconventional pollutant that controls certain toxic and nonconventional pollutants. The results of the round robin toxicity testing summarized in Table V-4, Section V of this document show how regulation of toxicity directly controls the type and amount of mineral oil (and the pollutants, such as the PAHs, identified as constituents of mineral oil). Addition of three percent mineral oil resulted in a significant increase in toxicity which would have resulted in noncompliance and transport of the drilling muds to land for disposal.

Barite is mined from either bedded or veined deposits. Research has shown that bedded deposits are characterized by substantially lower concentrations of heavy metal contaminants including mercury and cadmium. (See Table VII-2.)

In the final rule, EPA is limiting mercury and cadmium to 1 mg/l and 3 mg/l in stock barite. This limitation indirectly controls the levels of toxic pollutant metals because cleaner barite that meets the mercury and cadmium limits is also likely to have reduced concentrations of other metals. Evaluation of the relationship between cadmium and mercury and the trace metals in barite shows a correlation between the concentration of mercury with the concentration of arsenic, chromium, copper, lead, molybdenum, sodium, tin, titanium and zinc; and the concentration of cadmium and concentrations of arsenic, boron, calcium, sodium, tin, titanium and zinc. (SAIC, "Descriptive Statistics and Distributional Analyses of Cadmium and Mercury Concentrations in Barite, Drilling Fluids, and Drill Cuttings from the API/USEPA Metals Database," February 1991).

2.4 Pollutants Not Regulated

While the four limitations above limit the discharge of toxic and nonconventional pollutants found in drilling fluids and drill cuttings, and the conventional pollutant oil and grease, EPA has determined that certain of the toxic and nonconventional pollutants are not controlled by the limitations on diesel oil, free oil, toxicity, and mercury and cadmium in stock barite. EPA exercised its discretion not to regulate these pollutants because EPA did not detect these pollutants in more than a very few of the samples within the subcategory and does not believe them to be found throughout the offshore subcategory; the pollutants when found are present in trace amounts not likely to cause toxic effects; and due to the large number and variation in additives or specialty chemicals that are only used intermittently and at a wide variety of drilling locations, it is not feasible to set limitations on specific compounds contained in additives or specialty chemicals.

3.0 PRODUCED WATER

In the Offshore Guidelines, EPA is controlling pollutants contained in produced water by limiting oil and grease to 29 mg/l monthly average and a 42 mg/l daily maximum. These limitations represent the appropriate level of control under BAT and NSPS. Pollutants contained in produced water discharges from platforms with treatment systems used to meet the BPT level permit limits were identified by evaluating effluent data from the 30-platform study. A summary of the data from the 30 platforms is contained in Appendix 2 of this document. This study identified seven organic toxic pollutants and one priority metal as being present in produced water discharges following treatment for oil and grease (oil removal). The toxic pollutants are toluene, phenol, naphthalene, ethylbenzene, benzene, 2,4-dimethylphenol, bis(2-ethylhexyl) phthalate and zinc, and the long-term concentrations of these analytes, as determined from the 30-platform data set, are contained in Table IX-9, Section IX of this document. Additional toxic metals are identified as a result of the data evaluation (cadmium, copper, lead, nickel and silver) at much lower concentrations than zinc. The concentration of 2,4-dimethylphneol (at 14.4 μ/l) is also much lower than the other organic priority pollutants contained in Table IX-9. In addition, as shown in Table IX-8, the percent occurrence for other toxic organic pollutants in the effluent samples was lower for several analytes (10-32 percent), very low for a number of analytes (2-7 percent), and not detected at all for a large number of the priority organic pollutants. Results of this evaluation are used since the 30 platforms were selected for characteristics such as wide geographical distribution and type of production.

Oil and grease serves as an indicator for toxic pollutants in the produced water waste stream, including phenol, naphthalene, ethylbenzene, and toluene. EPA has determined that it is not technically feasible to control these toxic pollutants specifically, and that the limitations on oil and grease in produced water reflect control of these toxic pollutants at the BAT and NSPS levels.

As part of the Agency's evaluation of pollutant loading reductions for the various technology based options considered, additional data on discharges of priority toxic and nonconventional pollutants were evaluated. A number of studies, in addition to the 30-Platform Study, were evaluated and estimates concerning other pollutants being discharged and their concentrations at the various levels of control technology were made. The results of these estimates are contained in Section IX of the document in Table IX-9, Pollutant Concentrations in BPT Treated Produced Water From the 30 Platform Study. A summary of the pollutant data from these studies is also shown in Appendix 2.

Data from these studies, except for the 30-Platform Study data discussed previously in this section, are not appropriate for use in either setting limitations or in evaluating their removals directly or incidental to the use of technology for removal of oil and grease. For most of the studies, i.e., those submitted by industry during the development of the limitations, there is a lack of sufficient information on sampling protocols, analytical procedures and the quality control assurance, and production activity during the time of sampling. For the three-facility filtration study, the data is an estimate of BPT level treatment (prior to filtration) since these facilities were selected because of the use of filtration technology, and were not treating the waters for discharge since the facilities were reinjecting the produced water for secondary recovery purposes.

The feasibility of regulating separately each of the constituents of produced water determined from the 30-Platform Study data was evaluated. As discussed above, because of the limitations of the other data sets all of the pollutants used for loadings estimates were not deemed appropriate for consideration for discharge limits without more data. Other factors considered in the determination that setting limitations on all of those pollutants is not feasible or is not necessary in some cases are: the variable nature of the number of constituents in the produced water, impracticality of measuring a large number of analytes, many of them at or just above trace levels, use of technologies for removal of oil (as oil and grease) which are effective in removing many of the specific pollutants, and that many of the organic pollutants are directly associated with oil and grease because they are constituents of oil thus are directly controlled by the oil and grease limitation. EPA believes that the limitations on oil and grease contained in the Offshore Guidelines effectively control levels of certain toxic and nonconventional pollutants. EPA has data that demonstrate that control of oil and grease controls the toxic pollutants shown in Table IX-9.

Use of the gas flotation technology with chemical addition removes both metals and organic compounds. The insoluble metal hydroxide particle formation and adsorption by the chemical (polymer) floc of oil and the action of the gas bubbles forces both the oil (oil and grease) containing floc and metal hydroxide floc to the surface for removal (skimming), thus resulting in lower concentration levels in the discharge for the above priority pollutants. (See Section IX for discussions of gas flotation technology.)

3.1 POLLUTANTS NOT REGULATED

While the limitations above limit the discharge of toxic and nonconventional pollutants determined to be present in produced water treated to meet BPT control, EPA has determined that certain of the toxic priority pollutants, such as pentachlorophenol, 1,1-dichloroethane, and bis(2-chloroethyl) ether are not controlled by the limitations on oil and grease in produced water. EPA exercised its discretion not to regulate these pollutants because EPA did not detect them in more than a very few of the samples within the subcategory (see Table IX-8, Percent Occurrence of Organics for Treated Effluent Samples, 30 Platform Study); and the pollutants when found were present in trace amounts not likely to cause toxic effects.

4.0 WELL TREATMENT, COMPLETION AND WORKOVER FLUIDS

In the Offshore Guidelines, EPA is controlling pollutants found in well treatment, completion and workover fluids commingled and treated with produced water by limiting oil and grease to 29 mg/l monthly average and a 42 mg/l daily maximum. Separate discharges of these wastes are limited by both the above oil and grease limitations and a prohibition on the discharge of free oil. These limitations represent the appropriate level of control under BAT and NSPS.

The pollutants identified to be present in well treatment, completion and workover fluids are summarized in Tables X-12, X-13, and X-14 for workover, completion and well treatment fluids.

Oil and grease serves as an indicator for toxic pollutants in the well treatment, workover and completion fluids waste stream, including, phenol, naphthalene, ethylbenzene, toluene, and zinc. EPA has determined that it is not technically feasible to control these toxic pollutants specifically, and that the limitations on oil and grease in well treatment, workover, and completion fluids reflect control of these toxic pollutants at the BAT and NSPS levels.

EPA has determined, moreover, that it is not feasible to regulate separately each of the constituents in well treatment, completion and workover fluids because these fluids in most instances become part of the produced water wastestream and take on the same characteristics as produced water. Due to the variation of types of fluids used, the volumes used and the intermittent nature of their use, EPA believes it is impractical to measure and control each parameter. However, because of the similar nature and commingling with produced water, the limitations on oil and grease in the Offshore Guidelines will control levels of certain toxic priority and nonconventional pollutants for the same reason as stated in the previous discussion on produced water.

4.1 POLLUTANTS NOT REGULATED

While the oil and grease and, in certain instances, the no free oil limitations limit the discharges of toxic and nonconventional pollutants found in well treatment, completion and workover fluids, certain other pollutants are not controlled. EPA exercised its discretion not to regulate these pollutants because EPA did not detect them in more than a very few of the samples within the subcategory and does not believe them to be found throughout the offshore subcategory; and the pollutants when found are present in trace amounts not likely to cause toxic effects.

5.0 PRODUCED SAND

In the offshore Oil and Gas Effluent Guidelines, EPA is controlling all pollutants found in the produced sand wastestream by a zero discharge limitation. This limitation represents the appropriate level of control under BAT, BCT and NSPS.

Produced sand consists of the slurried particles used in hydraulic fracturing and the accumulated formation sands and other particles (including scale) generated during production. This wastestream also includes sludges generated by a chemical polymer used in the flotation or filtration (or other portions) of the produced water treatment system. Produced sand is generally contaminated with crude oil from oil production or condensate for gas production. In addition, some produced sand contains elevated levels of naturally occurring radioactive materials (NORM).

The specific conventional, toxic and nonconventional pollutants found to be present in produced sand are summarized in Table X-2, Average Oil Content in Produced Sand, Tables X-3 and X-4, Summary of Radioactivity Data for Produced Sand from OOC Survey and Average Radioactivity Levels in Produced Sand, respectively, and Table XIII-2, Produced Sand Characteristics. The specific pollutants controlled by the limitation are oil and grease, TSS, and priority and nonconventional pollutants constituents of oil including those described previously in this section. In addition, radium 226 and radium 228, which are NORM and considered to be nonconventional pollutants are controlled with the elimination of discharges of produced sand that contain elevated levels of NORM.

6.0 DECK DRAINAGE

In the Offshore Oil and Gas Effluent Guidelines, EPA is controlling pollutants found in deck drainage by the prohibition on the discharge of free oil. This limitation is the current BPT level of control and represents the appropriate level of control under BCT, BAT and NSPS.

The specific conventional, toxic and nonconventional pollutants found to be present in deck drainage are those primarily associated with oil, with the conventional pollutant oil and grease being the primary constituent. In addition, other chemicals used in the drilling and production activities and stored on the structures have the potential to be found in deck drainage. The specific pollutant concentration ranges found in untreated deck drainage are summarized in Table X-16, Characteristics of Deck Drainage from Offshore Platforms and Table X-17, Pollutant Concentrations in Untreated Deck Drainage.

The specific conventional, toxic and nonconventional pollutants controlled by the prohibition on the discharges of free oil are the conventional pollutant oil and grease and the constituents of oil that are toxic and nonconventional pollutants (see previous discussion in Subsection 2.2 of this section describing the chemical constituents of oil). EPA has determined that it is not technically feasible to control these toxic pollutants specifically, and that the limitation on free oil in deck drainage reflects control of these toxic pollutants at the BAT and NSPS level. In addition, the use of best management practices in order to prevent the buildup of waste material on deck surfaces due to spillage, minimize the use of soaps and detergents in deck cleaning, and perform deck washdowns more often to prevent overload of the oil separating devices during rainfall events will reduce the amount of pollutants entering the deck drainage waste stream.

As discussed in the Basis for Regulation, Section XV of this document, additional controls on deck drainage were rejected based on the technical infeasibility of deck drainage add-on systems to existing sump and skim pile systems currently being used. Deck drainage discharges are not continuous, vary significantly in volume, and contain a wide range of chemical constituents and concentration levels of the constituents, many of which are at or near trace levels. At times of platform washdowns, the discharges are of relatively low volume and anticipated; during rainfall events, very large, unanticipated volumes may be generated.

7.0 REFERENCES

SAIC, "Descriptive Statistics and distributional Analysis of Cadmium and Mercury Concentrations in Barite, Drilling Fluids, and Drill Cuttings from the API/USEPA Metals Database," prepared for Industrial Technology Division, U.S. Environmental Protection Agency, February 1991. (*Offshore Rulemaking Record Volume 120*).

SECTION VII

DRILLING FLUIDS - CHARACTERIZATION, CONTROL AND TREATMENT TECHNOLOGIES

1.0 INTRODUCTION

The first part of this section describes the sources, volumes, and characteristics of drilling fluids generated from offshore oil and gas exploration and development activities. The second part of this section describes the control and treatment technologies currently available to reduce the volume of drilling fluids and the quantities of pollutants discharged to surface waters.

2.0 DRILLING FLUIDS SOURCES

Drilling fluids, or muds, are suspensions of solids and other materials in a base of water or oil which is specifically formulated to: lubricate and cool the drill bit, carry drill cuttings from the hole to the surface, and maintain downhole hydrostatic pressure. Drilling fluids typically contain a variety of specialty chemicals to: control density (weight) and viscosity, reduce fluid loss to formation, and inhibit corrosion, etc.

Drilling fluids are formulated at the drill site according to the drilling conditions. Once formulated, the fluid is pumped down the drill pipe and ejected to the borehole through the drill bit. The drilling fluid returns to the surface through the annulus (space between the casing and the drill pipe). As the mud travels up the annulus, it carries the drill cuttings in suspension. The mud passes through the solids control equipment (shaleshaker, screens, hydrocyclones, etc.) to remove the cuttings, and is returned to the mud tank for recirculation.

Excess drilling fluids are removed from the mud circulation system during the drilling operation and at the end of the drilling program for various reasons. Excess drilling fluids are generated during drilling because: (1) At deeper depths the borehole is smaller, requiring less volume of drilling fluid, (2) The mud is diluted to maintain constant rheological properties, and (3) The entire mud system is periodically changed over in response to changing drilling conditions. At the end of the drilling program, the remaining mud left over in the circulation system and the storage tanks is either considered waste or recycled and/or regenerated for future use.

3.0 DRILLING FLUIDS VOLUMES

Drilling fluids discharges are typically in bulk form and occur intermittently during well drilling and at final well depth. Low volume bulk discharges are the most frequent and are associated with mud dilution, the process of maintaining the required level of solids in the fluid system. High volume bulk discharges occur less frequently during a well drilling operation, and are associated with drilling fluid system changeover and/or emptying of the mud tank at the end of the drilling program.

The volume of drilling fluid generated and the volume of drill cuttings recovered at the surface will depend on the following:[1]

- Size and type of drill bit
- Hole enlargement
- Type of formation drilled
- Efficiency of solids control equipment
- Type of drilling fluid
- Density of drilling fluid.

The size and type of drill bit determine the borehole diameter and the characteristics of the drill cuttings generated. Drill bits with large teeth produce large cuttings while other bits, like diamond bits, produce small cuttings, often in the powder form. Very fine solids from drill cuttings are entrained into the drilling fluid and can significantly effect the mud's rheological properties.

The amount of hole enlargement and type of formation determine the amount of drill cuttings brought to the surface. The hole volume can increase by as much as fifty percent due to erosion of the borehole from mud circulation. The amount of borehole wall erosion, or sloughing, is also dependent on the type of the formation being drilled. Soft formations will erode more than hard stable formations. The type of formation also determines the characteristics of the drill solids that disperse into the drilling fluid.

The efficiency of the solids control system is a major factor in the amount of excess drilling fluids generated. The solids control system is a mechanical separation process designed to separate the drilled solids from the drilling fluid. The combined drilling fluid and drill cuttings stream is processed in the solids control system and the drilling fluid is pumped downhole after the drill solids are removed. Solids control efficiency is based on the system's ability to remove a high percentage of low gravity drill solids from the mud. The low gravity solids adversely affect the rheological characteristics of the mud (viscosity, density, gel strength, etc.). The only method to counter the effect of the low gravity solids concentrating in the drilling fluid (after mechanical solids control) is mud dilution or displacement. Dilution and displacement are techniques of reformulating the mud to its original characteristics through removing a portion of mud from the system and adding water or fresh mud to the existing mud system. Poor solids control efficiency results in a large volume of excess drilling fluid because of the frequent dilutions required to maintain the required mud characteristics.

The type and density of the drilling fluid also determines the amount of excess drilling fluid generated. The Drilled solids well disperse less in some muds than others. For example drilled solids disperse less in potassium chloride and oil based-muds than in water-based muds. The density of the drilling fluid determines the total volume of the drilling fluid generated since more mud products are added to the fluid to increase the density.

A distinction should be made between the volume of drilling fluids formulated, or generated, and the volume of drilling fluids discharged. Some drilling fluid is lost to the geologic formations or left in the well annulus at the completion of drilling. Ayers, et al.[2] presented a materials balance estimate of drilling fluids components used in a Mid-Atlantic drilling operation. Of the 866 metric tons of barite used, 87 percent was discharged, 6 percent was left downhole, and 7 percent was unaccounted for. For bentonite plus drilled solids, 89 percent was discharged, 1 percent was left downhole, and 10 percent was unaccounted for. For the combined usage of lignite, chrome lignosulfonate, and cellulose polymer, 95 percent of the material was discharged and 5 percent was unaccounted for. The volumes not accounted for were assumed to be lost to the formations and/or left downhole.

A report by the Offshore Operators Committee presented data from two drilling projects in the Gulf of Mexico.[1] The report presented drilling data from a 10,000 foot well and a 18,000 foot well. Table VII-1 presents volumes of drilling fluids and drill cuttings discharged for both wells. The drilling fluid system used in both drilling projects was a seawater/bentonite mud to 4,500 feet and a lignosulfonate mud to final well depth. The volumes of drilling fluids generated includes fluids lost to the formation and drilled solids incorporated into the drilling fluid. The solids control system was assumed to be operating at fifty percent efficiency. In estimating the amount of cuttings and muds generated for the compliance cost analysis, EPA used the volume estimates presented in this report as a basis.

TABLE VII-1

VOLUME OF DRILLING FLUID & CUTTINGS DISCHARGED[1]

Depth of Interval (Feet)	Hole Size (In.)		Hole Volume (Bbls.)		Cuttings Discharge (Bbls.)		Fluid Generated (Bbls.)		Fluid Vol. Discharge (Bbls.)	
	10,000	18,000	10,000	18,000	10,000	18,000	10,000	18,000	10,000	18,000
0 - 150	36	36	188	188	188	188	–	–	–	–
150 - 1,000 (850)	25	32	516	846	258	423	3,133	5,136	1,477	1,956
1,000 - 4,500 (3500)	18	20	1,102	1,361	551	680	6,691	8,263	2,012	2,237
4,500 - 10,000 (5500)	11	–	647	–	433	–	2,593	–	1,860	–
4,500 - 12,000 (7500)	–	15	–	1,641	–	1,100	–	6,575	–	3,713
12,000 - 18,000 (6000)	–	10	–	583	–	390	–	2,336	–	2,580
Total Volume			2,453	4,619	1,430	2,781	12,417	22,310	5,349	10,486

4.0 DRILLING FLUIDS CHARACTERIZATION

Several broad categories of drilling fluids exist such as: water-based fluids (fresh or salt water), low solids polymer fluids, oil-based fluids, and oil emulsion fluids. This document discusses only the characteristics of water-based and oil-based fluids because they represent the majority of drilling fluids currently used in offshore drilling operations.

Oil-based muds are only used for specific drilling conditions because they cannot be discharged and thus are more expensive to use than water-based muds. The discharge of oil-based muds and associated cuttings is prohibited under the BPT limitation of "no discharge of free oil." Industry has indicated that oil-based drilling fluids continue to be the material of choice for certain drilling conditions. These conditions include the need for thermal stability when drilling high-temperature wells, specific lubricating characteristics when drilling deviated wells, and the ability to reduce stuck pipe or hole wash-out problems when drilling thick, water-sensitive shales. In 1991, the industry estimated that oil-based muds are used for approximately 15 percent of wells drilled greater than 10,000 feet.[3] A primary concern when using conventional, oil-based mud systems is their potential for adverse environmental impact in the event of a spill. Because of the relatively high toxicity of diesel oil, some *mineral oil-based* mud systems have recently replaced diesel oil-based muds.

The majority of mud systems used in offshore drilling are water-based fluids. Water-based drilling fluids are dense colloidal slurries in a water phase of either fresh or saturated salt mixtures. Salt water-based drilling fluids may be comprised of: seawater, sodium chloride (NaCl), potassium chloride (KCl), magnesium chloride ($MgCl_2$), calcium chloride/bromide ($CaCl_2$/$CaBr_2$), or zinc chloride/bromide ($ZnCl_2$/$ZnBr_2$). All freshwater muds contain bentonite (sodium montmorillonite clay) and caustic soda (NaOH), while saltwater muds may contain attapulgite clay instead of bentonite. Clays are a basic component of drilling fluids used to enhance the fluid viscosity. The most common required mud properties and the additives used to enhance these properties are discussed below.

4.1 PROPERTIES OF DRILLING FLUIDS AND ADDITIVES

Several different formulations of drilling fluids and additives can be created to achieve the required downhole conditions. The most common properties of the drilling fluid that the mud engineer controls are:

- Rheology
- Density
- Fluid Loss Control
- Lubricity
- Lost Circulation
- Corrosion and Scale Control
- Solvents
- Low Solids/Polymer Fluids
- Bactericides.

Each of these properties can be tailored to each well and drilling condition through the addition of active solids, inactive solids, and chemicals to the base drilling fluid. The following paragraphs provide a discussion of these properties and the additives that yield these properties.[4]

Rheology: During the drilling program, drilled clays may thicken the mud requiring that thinners and dispersants be added to control rheological (fluid flow) properties. There are four major thinners used for this purpose: lignosulfonate (where some contain chrome, ferrochrome, iron, calcium, sodium, titanium), lignite (sometimes treated with chrome, sodium, or potassium hydroxide), phosphates (sodium acid pyrophosphate and tetrasodium pyrophosphate), and plant tannis (quebracho is the most predominant).

Density: Materials of high specific gravity are required to control downhole pressure. These materials, however must be inert to the liquid phase of the drilling fluid. Many high density materials can be used. Of these barite (naturally occurring barium sulfate ore) is the most widely used. The amount of weighting agent required will depend upon the desired mud density, and the specific gravity of the weighting agent used.

Fluid Loss Control: A properly designed drilling fluid system will deposit a filter cake on the well bore wall during drilling to retard the passage of the liquid phase into the formation. Bentonite and drilled clays are the prime builders of this filter cake. When the drilling formations are extremely porous, additional fluid loss control additives are necessary. Some of the most common fluid loss control additives are: starch (corn or potato), sodium carboxymethyl-cellulose, polyanionic cellulose polymer, sodium polyacrylonitrile polymer, lignite, co-polymers of acrylamide and acrylic acid, xanthan gum, sodium polyacrylates, and hydroxyethylcellulose.

Lubricity: Under normal drilling procedures, the drilling mud alone is sufficient for adequate lubrication of the drill bit. When extreme loading to the drill bit is observed, a lubricant is added to the drilling fluid to improve bit life and performance. The most commonly used lubricity agents in the offshore drilling industry are mineral and diesel oils as well as the newly introduced synthetic lubricants. However, lubrication can also be achieved through the use of products composed of one or more of the following chemicals: acetophones, alcohol ester, aluminum stearate, asphalts, calcium oleate, coconut diethanolamides, coconut oil alkanolamide, diesel oil, diphenyl oxide sulfonate, ethoxylates, ethoxylated alcohol, fatty acids soaps, gilsonite, glycerol dioleate, glycerol monoleate, glass beads, graphite, lanolin, low order paraffinic solvents, mineral oil, organic phosphate ester, rosin soap, sodium alkylsulfates, sodium asphalt sulfonate, sodium phosphates, sorbitan ester sulfonate, stearates, sulfonated alcohol ether, sulfonated tall oil, sulfonated vegetable oil, triethanolamine, vegetable oils, and wool greases.

Lost Circulation: Lost circulation is one of the most common problems encountered in rotary drilling. Lost circulation refers to the loss of the whole drilling fluid to formations that are extremely porous or cavernous. Lost circulation additives plug the holes and/or gaps that allow the mud to enter *the formation*. These additives are either fibrous, filamentous, or granular/flakes. The materials used for lost circulation control are: ground nut shells, mica, ground cellophane, diatomaceous earth, baggasse (cane fiber), vegetable fibers, cottonseed hulls, ground or shredded paper, animal hair or feathers.

Corrosion and Scale Control: Corrosion of downhole tubular pipe is a serious problem to the drilling industry. Corrosion and scaling are minimized or eliminated through the addition of corrosion inhibitors to the mud system. There are three major sources of corrosion encountered in drilling operations. They are: oxygen, carbon dioxide, and hydrogen sulfide. Oxygen corrosion is due to oxygen entering the mud system from different points and being dissolved. Carbon dioxide corrosion is due to carbon dioxide entering the mud system from the formation and attacking the metal surface as gas or carbonic acid. Hydrogen sulfide corrosion (hydrogen embrittlement) is due to the presence of hydrogen sulfide in formations. Corrosion is inhibited through the use of mud additive products composed of one or more of the following chemicals: sodium sulfite, ammonium bisulfite, sodium dichromate, sodium chromate, zinc chromate, tall oil, amines, high molecular weight morpholines, organically chelated zinc, calcium sulfate, sodium hydroxide, zinc carbonate, copper carbonate, zinc oxide, iron oxide, phosphates.

Solvents: Some of the additives are liquid blends which require solvents for fluidity and freezing point depression. The following solvents are used in certain specialty products: water, isopropanol, n-butanol, glycerol, naphtha, isobutanol, 2-ethylhexanol, amyl alcohol, ethylene glycol, ester alcohols, diesel oil, other alcohols (C_3 - C_{20}).

Low Solids/Polymer Drilling Fluids: There are many conditions, such as normal formation pressures with no sloughing or heavy shales, where drilling with clear water fluids is desirable. These fluids provide excellent rate of penetration. The fluids typically contain less than 5 percent solids and are comprised of water, bentonite, and various polymers.

There are two types of polymers used, based on their action as either adsorbents or viscosifiers. Adsorbents work on the clay solids while viscosifiers work on the liquid phase, both of which result in increased viscosity. The most commonly used polymers are: polyvinyl acetate - maleic anhydride co-polymer, co-polymer of acrylamide and acrylic acid, xanthan gum, polyanionic cellulose polymer, sodium polyacrylates, hydroxypropyl guar, sodium polyacrylate and polyacrylamide, starchs (corn, potato), carboxymethylcellulose, hydroxyethylcellulose.

Bactericides: Bactericides are occasionally required in muds subject to bacterial degradation. Under the current regulatory requirements, all bactericides used in drilling fluids are regulated by EPA under the Federal Insecticide, Fungicide, Rodenticide Act (FIFRA).

4.2 COMPONENTS OF DRILLING FLUIDS

EPA conducted a survey of drilling fluids used in wells drilled between 1981-1984 in the Gulf of Mexico.[5] Chemical inventories of base components and specialty additives used for 74 exploratory and development wells were collected. Survey findings indicate that four basic components account for about 90 percent by weight of all materials used in the mud systems for these wells. The four basic components are: barite, clays, lignosulfonates, and lignites. Other mud systems' components are lime, caustic soda, soda ash, and a multitude of specialty additives. A detailed description of these compounds follows.

Barite: Barite, also known as baryte or heavy spar, is a heavy, soft, and chemically inert mineral. Pure barite contains 58.8 percent barium (Ba) and 41.2 percent sulfate (SO_4) by weight. Commercial forms can run as low as 92 percent $BaSO_4$ and contain such impurities as silica, iron oxide, limestone, and dolomite, as well as trace metals.

The use of barite as a weighting material in drilling fluids accounted for 90 percent of the total United States consumption in 1989. Offshore wells, which on the average are deeper and have higher subsurface pressures than onshore wells, account for a disproportionately higher percentage of the total consumption.

Barite is considered a ubiquitous material because both barium and sulfur are common minerals in the earth's crust (16th and 14th in abundance, respectively), and because barium sulfate ($BaSO_4$) is virtually insoluble in seawater. Barite tends to form a fine precipitate and is found in a range of grain and textures.

Barite deposits are classified into three categories: (1) vein and cavity filling deposits; (2) bedded deposits; and (3) residual deposits. Residual deposits typically are mined in open pits after removal of overburden. Bedded and vein deposits may be mined by open pit or underground methods, depending on local conditions. Following extraction, most ore is beneficiated at the extraction site, usually by rigging or flotation. If deposits are pure enough beneficiation is not necessary. The purified barite is shipped to processing plants for crushing and grinding.

Surveys were conducted to determine the concentration of trace metals in vein and bedded barite deposits. Kramer, et. al., analyzed barite samples to determine trace metals concentrations. The data reported in this study are summarized in Table VII-2. Vein deposits show a much wider range of trace metals concentrations than do bedded sources. Some vein deposits contain trace metal at levels below ocean sediment and crustal averages, while others contain mercury, cadmium, and zinc in quantities on the order of 100 times greater.[6] Barite is the primary source of toxic metals in drilling fluid discharges. The principal metals of concern are mercury and cadmium.

Clays: Bentonite is the most widely used clay. Bentonite has a crystalline structure which causes it to swell upon contact with water. This gelating property has two benefits: it suspends solid material, and aids in the removal of drill cuttings from the borehole. The sealing properties of bentonite also enable it to form an impermeable filter cake on the wellbore wall. However, highly concentrated brine (formation water), will substantially reduce the swelling properties of bentonite. In these cases, attapulgite or sepiolite clays are used as substitutes for bentonite.

Lignosulfonates: Lignosulfonates, by-products of pulp and paper processes, are considered the best all-purpose deflocculants for water-based drilling fluids. Deflocculants are generally used to maintain the mud in a fluid state.

The most widely used form of lignosulfonates is ferrochrome lignosulfonate. This compound is preferred over other forms of lignosulfonates because it retains its properties in fluids with high soluble salt concentrations and over a wide alkaline pH range, it is resistant to common mud contaminants, and it is temperature stable to approximately 177°C (350°F). Chromium can represent up to 3 percent by weight of seawater ferrochrome lignosulfonate. The aqueous fraction of spent seawater ferrochrome lignosulfonate drilling fluid contains about 1 ppm chromium. Most of this chromium is in the less toxic trivalent form, and is bound to clay particles.[7]

Lignites: Lignites are used, like lignosulfonates, as deflocculants. Lignites are substantially less soluble in seawater than lignosulfonates. Lignite products are mostly used as thinners in freshwater muds and to reduce drilling fluid loss to formation, and control drilling fluid gelation at elevated temperatures.

TABLE VII-2

ANALYSIS OF TRACE METALS IN BARITE SAMPLES[6]

Source	Trace Metals Concentration on Dry Weight Basis (mg/kg)									
	Fe	Pb	Zn	Hg	As	Ca	Cd	Ni	Cu	Co
Literature Values:										
Vein Deposits	8-22,000	4-1,220	10-4,100	0.06-14	7*	2-26	<0.2-19	19**	2-97	ND
Bedded Deposits	100-3,000	<10	<200***	0.06-0.19	<500***	1-11	<50***	<5	3-20	<5-60
Kramer, et. al.:										
Vein Deposits	200-59,000	<2-3,370	<0.2-9,020	0.8-28	0.008-170					
Bedded Deposits	2,500-6,000	1-1.8	6-10	0.13-0.26	1.4-1.8		0.5-0.7	0.4-5.7	5.4-7.6	1-2.2
Reference Data:										
Crust Average	50,000	15	65	0.1	2	2	0.2	80	45	23
Ocean Sediment	50,000	110	40	0.3	8	8	1	240	350	100

* - One Sample
** - Mean of 83 Samples
*** - Semiquantitative Emission Spectrographic Method
ND - Not detected

Other Additives: Other compounds such as lime, caustic soda, soda ash, and specialty additives are used as drilling fluids components as dictated by well drilling requirements. Table VII-3 lists several common drilling fluid additives and their functions. Their quantities vary considerably from well to well. Based on the survey data of the 74 wells completed between 1981-1984 in the Gulf of Mexico certain trends were observed. Wells in federal OCS waters require on the average, more drilling fluids and specialty additives than do wells in state waters. Also, exploratory wells require more drilling fluids and specialty additives than do development wells. Average total mud consumption for the surveyed wells amounted to 3.1 million pounds per exploratory well and 0.8 million pounds per development well.[5]

4.3 DRILLING FLUID COMPOSITION

In 1983, EPA initiated a program to evaluate the characteristics of water-based drilling fluids for the 1985 rulemaking. The program selected eight generic mud types to represent water-based drilling fluids commonly used in the offshore drilling industry. See Section V.2.1 for more details on the analytical program. Table VII-4 identifies the individual components and concentrations for each generic mud type. The results of chemical and physical analyses are summarized in Table VII-5.

The eight generic drilling fluids were also analyzed for "free oil" by the static sheen method. Sheen tests were also conducted on two generic muds (generic mud No. 2 and No.8) that contained varying volumes of mineral oil. None of the generic muds caused a visible sheen on the test waters. The additional drilling fluids submitted by industry containing varying concentrations of mineral and diesel oil all showed positive static sheen test results.[10] Washed cuttings from oil-based mud systems all indicated positive static sheen test results. The results of the static sheen tests for the drilling fluids and drill cuttings analyzed by the EPA contract laboratory are presented in Table V-2 in Section V.2.4.

The generic drilling fluids were also analyzed for organic pollutants and metals. Organic priority pollutants, analyzed by gas chromatography/mass spectrometry (GC/MS), were not detected in any of the water-based generic drilling fluid formulations without lubricity additives. Priority organic pollutants were detected in the muds spiked with mineral oil. Table VII-6 presents the organic pollutants detected in the generic drilling fluids. The presence of metals in the generic muds were determined by atomic absorption spectrometry. A total of 10 of the 13 priority metals were detected in the generic formulations. In particular, for all the generic muds, cadmium and mercury were both present at concentrations below 1 mg/kg. Table VII-7 presents the metals concentrations in the generic muds.

TABLE VII-3

FUNCTIONS OF COMMON DRILLING FLUID CHEMICAL ADDITIVES[8]

Action	Typical Additives	Function
Alkalinity and pH Control	Caustic Soda; Sodium bicarbonate; Sodium carbonate; Lime	1. Control alkalinity 2. Control bacterial growth
Bactericides	Paraform aldehyde; Alkylamines; Caustic soda; Lime; Starch	Reduce bacteria count NOTE: Halogenated phenols are no longer permitted for OCS use
Calcium Removers	Caustic soda; Soda ash; Sodium bicarbonate; Polyphosphates	Control calcium buildup in equipment
Corrosion Inhibitors	Hydrated lime; Amine salts	Reduce corrosion potential
Defoamers	Aluminum stearate; Sodium aryl sulfonate	Reduce foaming action in brackish water and saturated salt muds
Emulsifiers	Ethyl hexanol; Silicone compounds; Lignosulfonates; Anionic and nonionic products	Create homogeneous mixture of two liquids
Filtrate Loss Reducers	Bentonite; Cellulose polymers; Pregelated starch	Prevent invasion of liquid phase into formation
Flocculants	Brine; Hydrated lime; Gypsum; Sodium tetraphosphate	Cause suspended colloids to group into "flocs" and settle out
Foaming Agents		Foam in the presence of water and allow air or gas drilling through formations producing water
Lost Circulation Additives	Wood chips or fibers; Mica; Sawdust; Leather; Nut shells; Cellophane; Shredded rubber; Fibrous mineral wool; Perlite	Used to plug pores in the well-bore wall to stop fluid loss into formation
Lubricants	Hydrocarbons; Mineral oil; Diesel oil; Graphite powder; Soaps	Reduce friction between the drill bit and the formation
Shale Control Inhibitors	Gypsum; Sodium silicate; Polymers; Lime; Salt	Reduce wall collapse caused by swelling or hydrous disintegration of shales
Surface Active Agents (Surfactants)	Emulsifiers; De-emulsifiers; Flocculants	1. Reduce relationship between viscosity and solids concentration 2. Vary the gel strength 3. Reduce the fluid plastic viscosity
Thinners	Lignosulfonates; Lignites; Tannis; Polyphosphates	Deflocculate associated clay particles
Weighting Material	Barite; Calcite; Ferrophosphate ores; Siderite; Iron oxides (hematite)	Increase drilling fluid density
Petroleum Hydrocarbons	Diesel oil; Mineral oil	Used for specialized purposes such as freeing stuck pipe

TABLE VII-4

GENERIC DRILLING FLUIDS COMPOSITION[9]

Generic Drilling Fluid Type	Base Components	Concentration
1. Potassium/Polymer	KCl	50.0 g
	Drispac (Super-Lo)	0.5 g
	X-C Polymer	1.0 g
	Barite	283.2 g
	Starch	2.0 g
	Seawater	257.6 ml
2. Seawater/Lignosulfonate	Attapulgite	30.0 ppbbl
	Chrome Lignosulfonate	15.0 ppbbl
	Lignite	10.0 ppbbl
	Polyanionic Cellulose	0.25 ppbbl
	Caustic	To pH 10.5-11.0
	Barite (17-18 ppg mud)	As Needed
	Seawater	As Needed
3. Lime	Benitonite	20.06 g
	Lime	5.01 g
	Barite	281.81 g
	Chrome Lignosulfonate	15.04 g
	Caustic	1.00 g
	Lignite	8.02 g
	Distilled Water	257.04 ml
4. Nondispersed	Bentonite	13.0 ppbbl
	Acrylic Polymer (for Suspension)	0.5 ppbbl
	Arcylic Polymer (for fluid loss control)	0.25 ppbbl
	Barite	190.7 ppbbl
	Deionized	299.6 ppbbl
5. Spud (slugged intermittently with seawater)	Bentonite	12.5 ppbbl
	Lime	0.5 ppbbl
	Barite	50.0 ppbbl
	Seawater/Freshwater	1.0 bbl
	Caustic	To pH 10.0
6. Seawater/Freshwater Gel	Bentonite	20.0 ppbbl
	Polyaninic Cellulose Sodium Carboxymethyl	0.50 ppbbl
	Cellulose	0.25 ppbbl
	Barite	20.0 ppbbl
	Sodium Hydroxide	To pH 9.5
	Seawater/Freshwater, 1:1	As Needed
7. Lightly Treated Lignosulfonate Freshwater/Seawater	Bentonite	20.0 ppbbl
	Chrome Lignosulfonate	5.0 ppbbl
	Lignite	3.0 ppbbl
	Soda Ash	1.0 ppbbl
	Carboxymethyl Cellulose	0.5 ppbbl
	Barite	178.5 ppbbl
8. Lignosulfonate Freshwater	Bentonite	15.0 g
	Chrome Lignosulfonate	15.0 g
	Lignite	10.0 g
	Carboxymethyl Cellulose	0.25 g
	Sodium Bicarbonate	1.0 g
	Barite	487.0 g
	Deionized Water	187.0 ml

g = Grams; ml = Milliliters; ppbbl = Pounds per barrel; ppg = Pounds per gallon

TABLE VII-5

POLLUTANT ANALYSIS OF GENERIC DRILLING FLUIDS[10]

Generic Mud No.	Type of Mud	pH	Specific Gravity	% Weight Loss (103°C) (b)	BOD_5 ACT in SOW (b)	BOD_5 POLY in SOW (b)	UOD_{20} ACT in SOW (b)	UOD_{20} POLY in SOW (b)	TOC (c)	COD (b)	O&G Sonication (b)	O&G Soxhlet Extract. (a)
1	KCl Polymer	8.05	1.74	34.1	1,813	2,037	4,223	3,407	3,040	8,000	532	4,860
2	Seawater Lignosulfonate	10.10	2.15	26.6	1,483	1,373	2,717	2,330	15,000	39,900	1,270	2,750
3	Lime	11.92	1.73	44.0	1,657	2,743	3,207	3,963	15,000	41,200	796	1,240
4	Nondispersed	8.60	1.44	659.6	< 50	10	136	286	1,220	4,200	520	1,820
5	Spud	8.10	1.09	90.1	< 50	9	160	124	100	420	597	140
6	Seawater/Freshwater	7.95	1.09	88.0	181	216	130	285	686	1,800	661	672
7	Lightly Treated Lignosulfonate	8.50	1.44	56.2	1,470	1,386	2,187	1,733	5,650	15,200	1,710	572
8	Lignosulfonate Freshwater	8.60	2.12	27.1	1,530	1,393	2,413	1,980	14,200	34,900	1,400	7,380
2-01	Mud 2 + 1% (Vol.) Mineral Oil	10.95	2.15	26.4	1,416	2,223	4,073	5,803	15,900	46,100	2,730	2,400
2-05	Mud 2 + 5% (Vol.) Mineral Oil	9.75	2.07	27.2	3,416	2,157	8,340	7,473	26,300	98,300	11,700	23,400
2-10	Mud 2 + 10% (Vol.) Mineral Oil	8.55	2.04	25.7	1,558	1,877	9,273	6,190	36,500	144,000	14,800	40,400
8-01	Mud 8 + 1% (Vol.) Mineral Oil	8.00	2.21	27.0	1,373	2,383	4,423	4,297	13,400	53,800	1,990	2,560
8-05	Mud 8 + 5% (Vol.) Mineral Oil	9.22	2.23	26.3	2,207	2,023	9,773	6,940	20,800	75,300	7,080	7,670
8-10	Mud 8 + 10% (Vol.) Mineral Oil	8.50	2.25	25.6	1,423	1,633	7,863	6,497	24,200	99,600	12,300	2,800

All Data on Dry Weight Basis
(a) - Average of duplicates
(b) - Average of triplicates
(c) - Average of three triplicates

TABLE VII-6

ORGANIC POLLUTANTS DETECTED IN GENERIC DRILLING FLUIDS[10]

Generic Mud No.	Type of Mud	Phenanthrene	Dibenzofuran	N-Dodecane (C_{12})	Diphenylamine	Biphenyl
1	KCl Polymer	-	-	899	-	-
2	Seawater Lignosulfonate	-	-	-	-	-
3	Lime	-	-	809	-	-
4	Nondispersed	-	-	819	-	-
5	Spud	-	-	854 (822)	-	-
6	Seawater/Freshwater Gel	-	-	847 (802)	-	-
7	Lightly Treated Lignosulfonate	-	-	736	-	-
8	Lignosulfonate Freshwater	-	-	780	-	-
2-01	Mud 2 + 1% (Vol.) Mineral Oil	1,060	-	726	-	-
2-05	Mud 2 + 5% (Vol.) Mineral Oil	8,270	827	6,540	-	867
2-10	Mud 2 + 10% (Vol.) Mineral Oil	19,300	1,040	13,300	4,280	2,290
8-01	Mud 8 + 1% (Vol.) Mineral Oil	-	-	-	-	-
8-05	Mud 8 + 5% (Vol.) Mineral Oil	5,580	-	9,380	-	-
8-10	Mud 8 + 10% (Vol.) Mineral Oil	11,100	933	8,270	5,200	1,120

Note: Concentrations are in $\mu g/kg$

TABLE VII-7

METAL CONCENTRATIONS IN GENERIC DRILLING FLUIDS[10]

Generic Mud No.	Concentrations (mg/kg Dry Weight Basis)							
	Zn	Be	Al	Ba	Fe	Cd	Cr	Cu
1	26.20	<1.0	190	246.0	1,890	0.220	<3.0	3.96
2	42.40	<1.0	1,150	74.0	2,860	0.472(b)	764	27.50
3	37.00	<1.0	743	41.2	2,170	0.378(b)	908	40.60
4	35.90	<1.0	876	286.0	1,120	0.446(b)	<3.0	6.78
5	8.68	<1.0	347	293.0	833	0.074(b)	<3.0	1.61
6	3.28	<1.0	536	65.4	392	0.042(b)	<3.0	0.70
7	2.26	<1.0	541	408.0	660	0.142(b)	299	2.86
8	90.40	<1.0	1,150	54.6	5,110	0.36	770	72.20
2-01	43.40	<1.0	1,200	71.3	2,520	0.395(b)	740	26.80
2-05	40.80	<1.0	1,400	144.1	3,350	0.717(b)	720	26.00
2-10	46.00	<1.0	955	23.8	2,800	0.470(b)	640	26.10
8-01	86.80	<1.0	988	1,240.0	4,980	0.18	610	68.90
8-05	66.60	<1.0	862	27.0	3,940	0.28	541	77.30
8-10	77.80	<1.0	857	39.5	5,020	0.36	560	42.80
Generic Mud No.	Ni	Pb	Hg	Ag(b)	As(b)	Se(b)	Sb(b)	Ti(b)
1	<6.0	7.74	0.2610	0.089	4.640	<3.0	4.000	0.078
2	<6.0	1.82(b)	0.2640	0.126	2.400	<3.0	0.260	0.201
3	<6.0	41.2	0.7530	0.314	17.200	<3.0	1.060	0.129
4	<6.0	52.5	0.4370	0.228	5.250	<3.0	0.473	0.114
5	<6.0	3.51(b)	<0.010	<0.060	0.258	<3.0	<0.060	<0.060
6	<6.0	1.53(b)	0.2970	<0.060	0.621	<3.0	<0.060	<0.060
7	<6.0	1.42(b)	0.0961	<0.060	0.497	<3.0	<0.060	<0.060
8	<6.0	17.80	0.3550	0.244	11.700	<3.0	0.794	0.071
2-01	7.76	6.83	0.1070	0.110	1.470	<3.0	0.239	0.175
2-05	9.80	6.20	0.0910	0.124	1.700	<3.0	0.522	0.184
2-10	6.98	1.17(b)	0.0720	0.110	1.970	<3.0	0.160	0.166
8-01	<6.0	24.50	0.3910	1.390	12.200	<3.0	2.650	0.080(c)
8-05	<6.0	13.00	0.3680	1.110	9.610	<3.0	2.700	0.074
8-10	<6.0	9.48	0.2870	1.140	9.240	<3.0	2.020	0.062(c)

(a) Average of two samples
(b) Samples run by graphite furnace
(c) Single analysis

The acute toxicity of the generic drilling fluids range considerably.[9] *No median effects (50% mortality)* were observed for three of the eight mud types. Potassium polymer mud was found to be the most toxic. The suspended particulate phase showed a 96-hour LC50 of 3 percent by volume, as measured by the bioassay test method proposed in Appendix 3 of the regulation to the 1985 proposal. A summary of bioassay results are presented in Table VII-8.

TABLE VII-8

RESULTS OF ACUTE TOXICITY TESTS WITH GENERIC DRILLING FLUIDS AND MYSIDS (MYSIDOPSIS BAHIA)[9]

Test Location	Generic Mud No.	Definitive Test (a) (96-Hr LC50 & 95% CL)	Positive Control (a) (96-Hr LC50 & 95% CL)	Definitive Test (b) (96-Hr LC50 & 95% CL)
EPA/ORD Gulf Breeze	1	2.7% SPP (2.5 - 2.9) (c)	5.8 ppm (4.3 - 7.6) (d)	3.3% SPP (3.0 - 3.5)
	2	51.6% SPP (47.2 - 56.5)	7.5 ppm (6.9 - 8.1)	62.1% SPP (58.3 - 65.4)
	3	16.3% SPP (12.4 - 20.2)	7.3 ppm (6.6 - 8.1)	20.3% SPP (15.8 - 24.3)
	4	12% mortality in 100% SPP	3.4 ppm (2.8 - 4.1)	—
	5	12% mortality in 100% SPP	Same as for #1	—
	6	20% mortality in 100% SPP	6.0 ppm (5.4 - 6.6)	—
	7	65.4% SPP (54.4 - 80.4)	Same as for #6	68.2 SPP (55.0 - 87.4)
	8	29.3% SPP (27.2 - 31.5)	Same as for #3	30.0% SPP (27.2 - 32.3)
EPA/ORD, Narragansett	1	2.8% SPP (2.5 - 3.0)	6.2 ppm (4.4 - 11.0)	—
	5	No mortality in 100% SPP	3.3 ppm (2.6 - 3.8)	—

LC50 - Lethal concentration to 50% of test organisms
SPP - Suspended particulate phase
CL - Confidence limit

(a) Calculations by moving average; no correction for control mortality unless started.
(b) Calculation by SAS probit; correction for all control mortality.
(c) The suspended particulate phase was prepared by mixing 1 part drilling fluid with 9 parts seawater. These values should be multiplied by 0.1 in order to relate the 1:9 dilution tested to the SPP of the whole drilling fluid.
(d) Corrected for 13% control mortality.

Drilling fluid toxicity has been shown to increase with addition of mineral and diesel oil. Drilling fluids spiked with mineral oil were less toxic than those spiked with diesel oil. These findings are consistent with results of other research activities conducted at EPA's Environmental Research Laboratory in Gulf Breeze, Florida.[11] This study also showed that mud toxicity is more closely related to diesel content than to mud type.

The Gulf of Mexico Offshore Operators Committee (OOC) conducted a study in 1984 to examine the composition of mineral and diesel oil.[12] Three mineral oils and six diesel oils were examined using both the EPA GC method and a series of GC/MS methods measuring such parameters as individual aromatic compounds, alkylated phenols, organic sulfur compounds and several others. Data gathered from this study indicate that there are similar constituents in both diesel and mineral oils but at significantly higher concentrations in the diesel. The analysis revealed quantitative differences in the total aromatic, total sulfur and organic sulfur contents, as well as in the concentrations of individual polyaromatic hydrocarbons (benzene, naphthalene, biphenyl, fluorene and phenanthrene alyl homologue series) and sulfur- and nitrogen- polycyclic aromatic compounds (PAC) (debenxothiophene and carbazole alkyl homologue series, respectively). Thus, the differences in amounts of these compounds in mineral and diesel oils accounts for the lower toxicity of mineral oil. The results of this study are presented in Table VII-9.

TABLE VII-9

ORGANIC CONSTITUENTS OF DIESEL AND MINERAL OILS[12]
Conc. in mg/ml, unless noted otherwise

Organic Constituents	Gulf of Mexico Diesel	Calif. Diesel	Alaska Diesel	EPA/API Ref. Fuel Oil	Mineral Oil A	Mineral Oil B	Mineral Oil C
Benzene	ND	0.02	0.02	0.08	ND	ND	ND
Ethylbenzene	ND	0.47	0.26	2.01	ND	ND	ND
Naphthalene	1.43	0.66	0.48	0.86	0.05	ND	ND
Fluorene	0.78	0.18	0.68	0.45	ND	0.15	0.01
Phenanthrene	1.85	0.36	1.61	1.06	ND	0.20	0.04
Phenol (ug/g)	6.0	ND	1.2	ND	ND	ND	ND
Alkylated benzenes (a)	8.05	10.56	1.08	34.33	30.0	ND	ND
Alkylated naphthalens (b)	75.68	18.02	25.18	38.73	0.28	0.69	ND
Alkylated fluorenes (b)	9.11	1.60	5.42	7.26	ND	1.74	ND
Alkylated phenanthrenes (b)	11.51	1.41	4.27	10.18	ND	0.14	ND
Alkylated phenols (ug/g) (c)	52.9	106.3	6.60	12.8	ND	ND	ND
Total biphenyls (b)	14.96	4.03	6.51	13.46	0.23	5.57	0.02
Total dibenzothiophenes (ug/g)	760	1200	900	2100	ND	370	ND
Aromatic content (%)	23.8	15.9	11.7	35.6	10.7	2.1	3.2

Note: The study characterized sic diesel oils and three mineral oils. For the purpose of the general comparison and summary presented above, the Alaska, California, and Gulf of Mexico diesels are assumed to be representative of those used in offshore drilling operations.

ND = Not Detectable
(a) Includes C_1 through C_6 alkyl homologues
(b) Includes C_1 through C_5 alkyl homologues
(c) Includes cresol and C_2 through C_4 alkyl homologues

5.0 CONTROL AND TREATMENT TECHNOLOGY

5.1 BPT TECHNOLOGY

BPT effluent limitations for offshore drilling fluids prohibit the discharge of free oil. Oil-based muds cannot be discharged to surface waters because they have been shown to cause a visible sheen upon the receiving waters. Compliance with these limitations can be achieved either by product substitution (substitute a water-based mud for an oil-based mud to comply with no discharge of oil-based muds; substitute mineral oil for diesel oil to comply with no free oil limitation for water-based muds), recycle and/or reuse of the drilling fluid, or by onshore disposal at an approved facility.

5.2 ADDITIONAL WASTE MANAGEMENT PRACTICES AND TECHNOLOGIES CONSIDERED

Waste management practices to control releases of priority pollutants from discharges of drilling fluids include:

- Product substitution - acute toxicity limitations
- Product substitution - clean barite
- Product substitution - mineral oil
- Onshore treatment and/or disposal
- Waste minimization - enhanced solids control
- Conservation and recycle/reuse.

A detailed discussion of these practices is presented in the following sections. In addition, several technologies are also discussed which were evaluated during the study of controlling drill waste discharges, including:

- Thermal Distillation/oxidation
- Solvent extraction
- Grinding/reinjection
- Incineration.

5.2.1 Product Substitution - Acute Toxicity Limitations

EPA's acute toxicity analysis of the eight generic muds indicated that low toxicities can be achieved through the use of water-based drilling fluids and low toxicity specialty additives. Thus, acute toxicity limitations would encourage operators to substitute low toxicity additives for high toxicity additives.

The eight generic muds were formulated to represent the wide range of drilling conditions encountered by the offshore drilling industry. The results of the toxicity testing for the eight generic muds were presented in Table VII-8. The toxicity analysis indicates that they all exhibit low toxicity except for the potassium chloride (KCL) polymer mud, generic mud Number 1. The suspended particulate phase 96-hour LC50 of this mud was 3 percent by volume, with a 95 percent confidence interval ranging from 3.0 percent to 3.5 percent. The potassium chloride polymer mud was considered to be a specialty mud for drilling projects in the Gulf of Mexico.

EPA considers that mud formulations similar to the eight generic muds can be substituted, along with low toxicity additives, for higher toxicity water-based muds. The eight generic muds demonstrate that low toxicity components and additives can be formulated to generate a functional low toxicity drilling fluid. By selecting the drilling fluid with the least common formulation and the highest toxicity level as the basis for the drilling fluid toxicity limitation (generic mud No. 1), EPA is confident that the toxicity limitation is achievable and will significantly reduce the discharges of toxic muds without significantly affecting offshore drilling industry.

5.2.2 Product Substitution - Clean Barite

Barite is a major component of drilling fluids which can represent as much as 70 percent of the weight of a high-density drilling fluid. Barite has been shown to contain varying concentrations of metals of toxic concern, particularly cadmium and mercury. Barium sulfate, the natural source of barite, has also been shown to contain varying concentrations of metals depending on the characteristics of the deposit from where the barite was mined. EPA's statistical analysis of the API/USEPA Metals Database indicate that there is some correlation between cadmium and mercury and other trace metals in the barium.[13] Thus, regulating the concentration of cadmium and mercury in barite would indirectly regulate all other metals present in barite.

EPA used six datasets to evaluate the achievability of compliance with a metals limitation in Barite.[13] These datasets come from the Diesel Pill Monitoring Program (DPMP), the Offshore Operators Committee's (OOC) Fifteen Rig Study (15RS), monitoring data from EPA's Region IX, and monitoring data from Region X, as well as two other studies performed in 1986 and 1988.

The DPMP study contains 38 cadmium and mercury measurements from a joint effort of EPA and API in Region VI. Limitations in the methods used to collect the data were considered in the analysis. The sampling design called for self-selected offshore oil and gas operators with stuck drilling pipes to submit self-monitoring reports. As an incentive to participate, operators were allowed to discharge, as opposed to hauling onshore, water-based drilling muds and cuttings after recovery of a diesel pill that was used to free the stuck pipe. Samples considered for this analysis were all collected before the diesel pill was spotted. Region VI did not have cadmium and mercury limitations at the time of this data collection.

The 15RS contains 14 cadmium and mercury measurements from a joint effort of API and OOC. The sampling design called for self-selected offshore oil and gas operators who were in the process of drilling wells, whose names and locations remain confidential, to submit standardized reports. Samples were analyzed by both industry and EPA.

The OOC also collected samples during 1986 and 1988. In 1986, drilling muds and barite were sampled. The sampling design called for self-selected offshore oil and gas operators who were in the process of drilling wells. Only total metal analyses data were used. In 1988 only barite was sampled. The sampling design also called for oil and gas operators who were in the process of drilling.

The Region IX data, measurements from four samples, are from discharge monitoring reports submitted by offshore oil and gas operators under the requirements of their permits. The Region IX general permit requires that barite used to formulate drilling fluid must contain 2 mg/kg or less of cadmium and 1 mg/kg or less of mercury.

The Region X data, measurements from 116 samples, are from discharge monitoring reports submitted by offshore oil and gas operators under the requirements of their permits. The Region X general permit requires that barite used to formulate drilling fluid must contain 3 mg/kg or less of cadmium and 1 mg/kg or less of mercury.

5.2.2.1 Compliance Rates—Achievability

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.[14]

All of the data sets show passing rates to some degree for all limitation options. Table VII-10 shows the percent of samples from each data set that pass the 5/3 and 3/1 cadmium/mercury barite limitations. One-hundred-percent compliance was exhibited by data from Region IX for both standards, with generally high percentage compliance rates for all data sets. Table VII-11 shows the percent of samples passing the three sets of standards for cadmium and mercury in the drilling fluids. Again, 100 percent compliance with all standards was exhibited by data from Region IX. Region IX shows a 100 percent compliance with this limit probably because their general permit has a 2/1 mg/kg limitation for cadmium and mercury, respectively, in the barite composition. Region X, which includes in its general permit 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 and mercury in drilling fluids. Data from Gulf facilities show a lower percentage of compliance; however, there are currently no metals limitations in their general permit. For comparative purposes, EPA evaluated in its regulatory options 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). EPA is also taking into account comments submitted by industry that 3/1 mg/kg (Cd/Hg) is technologically available and economically achievable.

TABLE VII-10

PERCENT OF SAMPLES PASSING BOTH CADMIUM AND MERCURY PROPOSED LIMITATIONS ON BARITE[14]

Standard	Study	Samples	Number of Samples Passing Both Cd and Hg	Percent Passing Cd and Hg
Standard 1	OOC86	15	14	93
5 mg/kg	OOC88	48	44	92
Cadmium	REG10	52	52	100
3 mg/kg	REG9	11	11	100
Mercury	15RS	14	12	86
	15RSEPA	14	12	86
Standard 2	OOC86	15	11	73
3 mg/kg	OOC88	48	32	67
Cadmium	REG10	52	52	100
1 mg/kg	REG9	11	10	91
Mercury	15RS	14	7	50
	15RSEPA	14	6	43

TABLE VII-11

PERCENT OF SAMPLES PASSING BOTH CADMIUM AND MERCURY PROPOSED LIMITATIONS ON DRILLING FLUIDS[14]

Standard	Study	Samples	Number of Samples Passing Both Cd and Hg	Percent Passing Cd and Hg
Standard 1	DPMP	38	6	16
1 mg/kg	OOC86	31	4	13
Cadmium	REG10	116	78	70
1 mg/kg	REG9	4	4	100
Mercury	15RS	14	8	57
	15RSEPA	13	3	23
Standard 2	DPMP	38	19	50
2.5 mg/kg	OOC86	31	27	87
Cadmium	REG10	116	102	88
1.5 mg/kg	REG9	4	4	100
Mercury	15RS	14	12	86
	15RSEPA	13	12	92
Standard 3	DPMP	37	8	21
1.5 mg/kg	OOC86	31	9	29
Cadmium	REG10	112	82	73
0.5 mg/kg	REG9	4	4	100
Mercury	15RS	14	7	50
	15RSEPA	13	4	31

5.2.2.2 Clean Barite Availability

In response to comments regarding concern over availability of barite supplies, EPA commissioned investigations into this for limitations on cadmium and mercury of either 1/1 mg/kg in the fluids or 5/3 mg/kg in barite.[15] This investigation reviewed foreign and domestic barite supplies, with compositions adequate to meet the proposed limitation, to the projected industrial demand. Two sets of limits were investigated: the 1/1 mg/kg each of cadmium and mercury in the drilling fluids, and 5/3 mg/kg of cadmium and mercury in the barite. The study was performed on 1985 data. This report first investigated the amount of available barite having a composition that could meet the metals limits. This information was obtained from a survey on cadmium and mercury content in barite. The survey covered only 8 countries while 47 countries are listed as producers in the 1985 Minerals Yearbook.[16] Results of this survey, extrapolated to 1985 production, are shown in Table VII-12. However, these 8 countries account for 3,911 thousand short tons out of 6,671 thousand short tons produced in 1985. It could not be estimated how much of the remaining 41 percent of 1985 production might have met either cadmium and mercury limitation. For the most adversely affected producer, Peru, none of the samples met the

1 mg/kg limitation and only one-third of the samples met the 5 mg/kg and 3 mg/kg limitations on cadmium and mercury. All U.S. samples met the 5 mg/kg and 3 mg/kg limitations while 82 percent met the 1 mg/kg each limitation for these metals.

TABLE VII-12

AMOUNT OF BARITE MEETING CADMIUM AND MERCURY LIMITATIONS - 1985 DATA[15]

Country	Quantity Produced or Imported to U.S. (000 short tons)	Meeting Hg and Cd Limits of 1 and 1 mg/kg		Meeting Hg and Cd Limits of 3 and 5 mg/kg	
		%	Quantity (000 sht. tns.)	%	Quantity (000 sht. tns.)
Chile	24	57	14	93	22
China	1,100	56	616	81	891
India	670	81	543	100	670
Mexico	540	36	194	79	427
Morocco	468	34	159	78	365
Peru	180	0	0	33	59
Thailand	190	33	63	100	190
U.S.	739	82	606	100	739
Total of Listed Countries	5,911		2,195		3,363
U.S. Barite Use in Well Drilling					
Total	2,042				
Onshore	1,096				
Offshore	946				

For the countries surveyed, 2,195 thousand short tons or 3,363 short tons of "clean" barite would have been available from 1985 production depending on the limits chosen for cadmium and mercury. Total U.S. barite use in 1985 for well drilling was 2,042 thousand tons. In other words, even though only 59 percent of world production was extrapolated, there would have been sufficient "clean" barite to meet all U.S. drilling needs, not just offshore.

Table VII-13 compares the projected barite needs to the "clean" barite *available based on 1985* production levels, assuming three different oil price scenarios. Under the 1 mg/kg each limitation, barite needs exceed 1985 domestic production but form only 28 to 41 percent of the production of the tested countries. Additional supplies are likely to be available from the untested countries as well.

TABLE VII-13

COMPARISON OF PROJECTED BARITE NEEDS AND SUPPLIES[15]

Price Assumption ($/bbl)	Average Annual Barite Requirements	Available Barite (1985 Production) (000 short tons)							
		Hg and Cd Limits of 1 and 1 mg/kg				Hg and Cd Limits of 3 and 5 mg/kg			
		United States		Tested Countries		United States		Tested Countries	
		Quantity	%	Quantity	%	Quantity	%	Quantity	%
15	613	606	101	2,195	28	739	83	3,365	18
21	742	606	122	2,195	34	739	100	3,365	22
32	894	606	148	2,195	41	739	121	3,365	27

Under the 5 mg/kg and 3 mg/kg limitations, 1985 domestic consumption alone would suffice to cover the number of wells projected for the $15/bbl scenario and almost cover the number of wells projected under the $21/bbl scenario. Under this limit, U.S. offshore barite needs would require only 18 to 27 percent of the 1985 production from the tested countries.

In response to comments that noncompliance would be caused by contributions from the formation, EPA has analyzed data from the American Petroleum Institute's Fifteen Rig Study.[13] 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 also analyzed by EPA. 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. These results suggest that cadmium, from a source other than barite, is contaminating the drilling fluid. Physical analyses by EPA indicates that 13 out of 13 rigs, for which results were reported, had higher cadmium concentrations in their drilling fluid than in their barite.

Based on the results of this analysis, EPA developed a profile of metals concentrations in drilling fluids where both "clean" and "dirty" barite were used. This information was compiled from the statistical analysis of the API/EPA Metals Database. Table XI-4 in Section XI presents these profiles as they were used to calculate regulatory options for metal pollutants reductions.

5.2.3 Product Substitution - Mineral Oil

In addition to using low toxicity drilling fluids, low toxicity lubrication additives can reduce the overall toxicity of the drilling fluid. For many years, diesel oil was the preferred additive for lubrication purposes and for spotting jobs. EPA has evaluated other lubricants that have similar properties to diesel but are less toxic. One of these products which has become a common substitute for diesel oil in recent years is mineral oil. Mineral oil is an adequate substitute for diesel as a torque-reducing agent and a spotting fluid, as demonstrated by the API Drilling Fluids Survey and the OOC Spotting Fluids Survey (see Section V.2).

An OOC sponsored analysis of organic chemical characterization of diesel and mineral oils used as drilling fluid additives indicated that there are similar constituents in both diesel and mineral oils but at significantly higher concentrations in the diesel.[17] The analysis revealed quantitative differences in the total aromatic, total sulfur and organic sulfur contents, as well as in the concentrations of individual polyaromatic hydrocarbons (benzene, naphthalene, biphenyl, fluorene and phenanthrene alyl homologue series) and sulfur- and nitrogen- polycyclic aromatic compounds (PAC) (debenxothiophene and carbazole alkyl homologue series, respectively). Thus, the differences in amounts of these compounds in mineral and diesel oils accounts for the lower toxicity of mineral oil.

In 1984, industry representatives acknowledged that mineral oil is an adequate substitute for diesel as a torque-reducing lubricity agent.[17] Several industry studies investigated the effectiveness of using diesel oil versus mineral oil in freeing stuck pipe. The data gathered from these studies indicated that: mineral oil was commonly used by operations in the Gulf of Mexico, mineral oil is an available alternative to the use of diesel oil, and success rates comparable to those with diesel oil can be achieved with mineral oil.

There are also several available synthetic hydrocarbon lubricants such as polyolefins and low toxicity vegetable oils that are effective in reducing torque and freeing stuck pipe.

5.2.4 Onshore Treatment/Disposal

Drilling fluids that do not meet the effluent limitations guidelines and standards of this rule can be hauled to shore for treatment and/or disposal. EPA determined that transporting drilling wastes to shore is currently practiced and technologically and economically feasible. EPA estimates that approximately 12 percent of all drilling fluids are brought to shore for treatment/disposal under the current regional BPJ NPDES General Permits. To evaluate the impact of increased onshore disposal volumes required under this rule, the EPA studied the availability and capacity of land disposal facilities. This section will describe the methods of onshore disposal of drilling wastes. Section XVIII.2.2 presents information on the available capacity of land facilities for disposal of offshore drilling waste.[18]

In 1987 sixteen disposal facilities from California, Louisiana, and Texas were surveyed to determine the disposal methods, costs, and available space. A variety of treatment/disposal systems were employed by the companies ranging from disposal of contaminated drilling fluids with and without treatment to treatment of the fluids and transferral of the treated material to another facility for final disposal. The typical methods of disposal were: landfills, land treatment, deep well injection, and mud reclamation. The number of companies utilizing each of the various methods is summarized as follows:

Number of Companies	Waste Treatment or Disposal Method
7	Landfill
2	Land treatment (landfarm)
1	Mud reclamation
1	Deep well injection (has applied for landfill permit)
5	Waste treatment - Gravity settlers, electroflotation - Evaporation using hot oil system - Drying/incineration - Thermal oxidation - Incineration.

The typical waste handling method for land disposal of drilling muds and cuttings noted in the survey was stabilization (i.e., solidification and fixation) of the mud with kiln dust or fly ash followed by landfilling. Solidification techniques consist of adding chemicals to the mud which react to form a solid material which can be disposed. The equipment consists of a specially designed blender to mix the drilling fluids and chemicals and to pump the slurry into the proposed areas for solidification. Six of the facilities surveyed used this method of disposal.

One facility disposes of the waste in lined impoundments. Upon arrival of the spent drilling waste at this facility, it is classified either as solid or liquid, and disposed accordingly. Solid and liquid wastes are placed in different lined impoundments.

One facility handles only bulk or drummed solids. The waste must have under 5 percent hydrocarbons present. All solids are placed in lined pits.

Two of the facilities dispose of drilling muds and cuttings by land farming. At one of these facilities, rainwater is collected with leachate and injected into a saltwater disposal well.

One company included in the survey is a supplier of muds to the industry that reclaims muds for reuse using the same method and equipment as is used on platforms and rigs. Credit is given to the companies supplying the spent mud against future purchases.

Although the companies with waste disposal facilities included in this survey predominantly used stabilization of muds followed by landfill, another waste handling method available for drilling muds and cuttings is the use of deep well injection for the liquid phase of drilling muds and landfill or land treatment for the solid phase of muds and cuttings. Due to the solid content of the drilling muds, a centrifuge must be used to separate the solids from the fluids prior to injection.

The usual methods of transportation from the drilling site to the licensed disposal facilities are: supply boats or barges for oil, mud slurries, and liquids; and dump trucks for land transport of drill cuttings or wastes which are classified as being in a dry condition.

This study also sought to determine the feasibility of onshore disposal of drilling fluids and cuttings from the perspective of land availability. Several steps were performed to make this estimate. Industry activities were estimated to the year 1995. In addition, the total volume of material to be disposed and the total acreage necessary to support disposal of this material were estimated. The total required acreage was compared with an assessment of actual land availability for this purpose.

The companies were also asked to supply information on the costs of disposal. Reported costs for landfilling after solidification of the drilling muds ranged from $33 per barrel to $110 per barrel.

At the waste disposal facility, where solids and liquids were disposed of by placing them in separate impoundments, the costs of disposal were quoted as $35 per ton for non-hazardous liquids and $65 per ton for non-hazardous solids, and $60 per ton for hazardous liquids and $80 per ton for hazardous solids.

Costs for waste treatment were quoted by two of the five companies providing processes for treating waste drilling fluids. The cost of rendering these wastes acceptable for disposal using centrifuging, gravity settling, and electroflotation was reported as being $7.50 per barrel for waste containing up to 10% oil and $9.75 per barrel for wastes containing over 10 percent oil. The cost of rendering drilling waste fluids acceptable for disposal using the combined drying and incineration process was reported to be in the range of $15 to $18 per barrel.

Costs were not available for the treatment of drilling wastes by the other three waste treatment processes covered in the survey.

The companies contacted in the survey provided only very limited information on transportation costs for drilling wastes. Costs were either not available or were on a case-by-case basis, dependent on location and distance to be moved. Disposal costs were usually quoted on received-at-site basis.

5.2.5 Waste Minimization - Enhanced Solids Control

Solids control equipment is used to remove drill cuttings and other fines and minimize the build-up of drilled solids in the drilling mud system. Reported benefits of enhanced solids control efficiencies include:

- Reduced drilling torque and drag
- Reduced swab and surge pressures
- Reduced tendency for differentially stuck pipe
- Fewer stuck logging tools
- Better cement jobs
- Higher penetration rates with reduced bit and stabilizer balling

- Better ability to run casing to bottom
- Longer bit runs
- More hole stability
- Reduced equipment wear and tear
- Reduced land disposal areas and disposal costs
- Reduced drilling fluids costs.[19]

Solids control equipment is typically provided and maintained by the drilling contractors.[20] Typically, a turnkey contractor will provide the equipment specified by: (1) the standard drilling contract - shale shaker, desander, desilter, or (2) additional requirements placed by the operator - high performance shale shaker, mud cleaner, centrifuge, etc.

The separation efficiency of the solids control equipment is defined as the percentage of low specific gravity solids removed from the active mud system in each drilling cycle. The separation efficiency is dependent on several factors such as: mud rheology, mud density, formation characteristics, low gravity solids concentration in the mud (typically maintained at no more than 5-7%), fluid flow rate, equipment design capacity, equipment piping and plumbing configuration, and equipment operator experience.[3]

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

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

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

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

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

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

5.2.6 Conservation and Reuse/Recycling

Depending on the type and cost of the drilling fluid selected, recycle and reuse of spent drilling fluids may be an attractive alternative to reducing pollutants discharged from offshore drilling operations. This is particularly true of fluids that have a hydrocarbon (diesel or mineral) liquid base. Economically attractive reuse practices for spent oil-based and synthetic-based drilling fluids are:

- Mud company buys back the used drilling fluid which is hauled to shore, processed, and reused.
- The spent drilling fluid is treated with additional solids-suspending agents and used as a packer fluid.

5.2.7 Thermal Distillation/Oxidation

In 1988, EPA investigated thermal distillation and oxidation processes for their potential in reducing the oil content of drilling wastes. Oil-based drilling fluids can typically contain 30 percent or more oil by volume. Because of the high oil content (and low water content) of oil-based fluids, significant quantities of oil can be recovered by these technologies. Four different thermal distillation and oxidation processes were evaluated for the removal of oil from drilling wastes (53 FR 41375, October 21, 1988).

One type of system (designated T-1) consists of an electrically heated chamber in which the drilling wastes are exposed to controlled heat sufficient to volatilize the residual oil and water in the wastes. The electrical energy required by the process is provided by onsite generators. The processed wastes in the form of a granular material are cooled and slurried with seawater before being discharged. Water and hydrocarbon vapors are condensed and separated in an oil/water separator. The recovered hydrocarbons can potentially be recycled and reused in active mud systems. Exhaust gases from the heating chamber and from the condenser would also have to be treated to achieve appropriate air emission standards. The results of sampling performed by the vendor and by EPA indicate that this technology is capable of reducing oil content levels to 1 percent or less by weight in processed cuttings associated with oil-based muds.

Another variation of the thermal distillation process (designated T-2) was developed to reduce hydrocarbons in drilling fluids and drill cuttings. In this process, the drilling wastes are fed into the drying section of the process where hydrocarbons and water are driven off from the wastes. The water and hydrocarbon vapors are passed through condensers and the resultant liquid is processed to separate the oil from the water. The oil is placed in storage for further purification and the water is further processed for additional oil/water separation. A prototype unit of this system was used to process drill cuttings. An oil content of less than 0.5 percent by weight was reportedly achieved in a test of this unit. However, a full-scale unit was not tested under actual field conditions.

A third variation of the thermal distillation process (designated T-3) uses indirect heat to vaporize water and hydrocarbons adhering to drilling wastes. Drilling wastes are first fed to a blender which maintains a homogeneous slurry feed to the unit process. A closed heat transfer system provides the heat required to vaporize the water and the hydrocarbons from the drilling waste. Heat to the processing unit is supplied by the exhaust gases from the rig electricity generator. The processed wastes are dry and granular in nature. Water and hydrocarbons vapors are condensed for recovery. The results of the pilot scale skid-mounted mobile unit reportedly produced cuttings with an oil content of 6 percent or less by weight. This process was not tested on a full scale basis.

A thermal oxidation process (designated T-4) consists of a direct fired, countercurrent rotary kiln where the wastes are thermally oxidized at temperatures in the range of 1600 F to 2500 F. The kilns can be over 200 feet in length. The dried solids produced in this process are reportedly suitable for use as aggregates or fill materials. The hydrocarbons driven from the wastes are partially oxidized in the kiln, while virtually complete combustion is achieved in an oxidation chamber and afterburner. In 1988, at least two of these facilities were known to be operating on the Gulf of Mexico. However, due to the scale of the equipment, this process can not be implemented offshore or moved from site-to-site. However, drilling wastes could be transported to such land-based facilities for processing.

Although these technologies appeared to be capable of reducing the oil content in oil-based drilling wastes, EPA rejected them from further consideration because of difficulties associated with the placement of such equipment at offshore drilling sites, operation of the equipment, intermediate handling of raw wastes to be processed, and handling of processed wastes and by-products streams. Finally, (1) full scale thermal distillation/oxidation treatment has not been successfully demonstrated on offshore platforms; (2) it requires excessive input of thermal energy when processing water-based drilling wastes; and (3) it does not reduce pollutants below the capability of BPT technology.

5.2.8 Solvent Extraction

In 1984, EPA evaluated a solvent extraction technology for reducing the oil content in drilling wastes.[21] The high oil content (and low water content) of oil-based fluids have resulted in highly efficient removal and recovery of the oil by solvent extraction.

In this process, the drilling wastes are fed to an extraction column and contacted with solvent to extract the oil. The oil-rich solvent flows from the extractor column to an evaporator, a separation column and an oil/solvent separator. The oil phase flows to the fluidizing oil holding tank and the solvent is recycled back to the process. Oil contents as low as 0.3 percent by weight in the processed wastes were reportedly achieved by this process. Two types of solvents have been used in the solvent extraction processes investigated by the Agency: chlorofluorocarbons and carbon dioxide. Although the solvents are used in a closed-loop type process, there exists the potential of solvent losses to the atmosphere.

Although solvent extraction appeared to be capable for the reduction of oil content in drilling wastes, EPA rejected it from further considerations because of difficulties associated with the placement of such equipment at offshore drilling sites, operation of the equipment, intermediate handling of raw wastes to be processed, and handling of processed wastes and by-products streams. In addition, the Agency is particularly concerned about the potential losses of chlorofluorocarbons to the atmosphere. Finally, this technology has not been successfully demonstrated on offshore platforms, and it does not reduce pollutants below the capability of BPT technology.

5.2.9 Grinding/Reinjection

In the March 13, 1991 proposal, EPA solicited comments on reinjection as a basis of zero discharge for drill waste, muds and cuttings. EPA received comments from the Alaskan Oil and Gas Association (AOGA) on a prototype cuttings grinder and washing system being tested onshore at Prudhoe Bay, Alaska.[22] In 1992, EPA obtained information on a drill waste injection system from a company operating a pilot injection system on a platform in the Gulf of Mexico.[23]

Drill waste injection systems consist of a slurrification system and an injection system. The cuttings are processed in a vibrating ball mill into a slurry that can be combined with the spent fluids and excess liquids from the drilling process. The slurry particle size for the system operating in Prudhoe Bay is 74 microns. The slurry is then pumped into the formation through a well annulus or into a dedicated disposal well.

This technology is very promising for application where there are suitable receiving zones and confining layers. Since the injection process depends on fracturing the receiving formation, there must exist a suitable formation that can be safely fractured. Furthermore, that formation must be confined by layers which will not be affected by the fracturing so that the injected material remains in place.

The system operating at Prudhoe Bay is reinjecting ground cuttings through a well annulus at about 3,000 ft into the Cretaceous zone. The disposal formations consist of poorly consolidated sediments with high permeability and a porosity estimated at 20 to 25 percent. These formations are easily fractured because they are not tightly cemented. In addition, the formations are isolated by confining layers, and there are no underground sources of drinking water.

The size of the system operating at Prudhoe Bay occupies 3,180 square feet. A similarly designed smaller unit is also planned for a onshore drilling location on the North Slope of Alaska. The particle size for the injection slurry is 100 microns. The area requirement for this unit is 1,280 square feet.

While ongoing design work may result in more compact units, this technology is not available for application to offshore platforms due to the lack of suitable formations across regions or the whole subcategory for injection and the inability of platforms to accommodate the large size of these systems.

5.2.10 Incineration

Incineration was considered as an alternative treatment option for drilling wastes. The Agency rejected incineration because of equipment size, energy costs, and possible fire hazards if used on offshore platforms. However, incineration may be applicable for treatment of drilling wastes that are transported onshore for reconditioning, treatment, and/or disposal, or the treatment of residuals from the processing of the wastes.

6.0 REFERENCES

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SECTION VIII

DRILL CUTTINGS—
CHARACTERIZATION, CONTROL AND TREATMENT TECHNOLOGIES

1.0 INTRODUCTION

The first part of this section describes the sources, volumes, and characteristics of drill cuttings generated from offshore oil and gas exploration and development activities. The second part of this section describes the control and treatment technologies currently available for the drill cuttings waste stream.

2.0 DRILL CUTTINGS SOURCES

Drill cuttings are small pieces of formation rock that are generated by the crushing action of the drill bit. Drill cuttings are carried out of the borehole with the drilling fluids. Fine drill solids disperse into the drilling fluids and can significantly effect the mud's rheological properties. Solids control is the process of maintaining the concentration of drill solids in the drilling fluid at a constant and desirable level. The most common solids control methods are dilution, displacement, and mechanical removal. In the offshore drilling industry, a combination of all three methods is employed to achieve the desired solids content of the drilling fluid.

2.1 SOLIDS CONTROL SYSTEM

Upon reaching the surface, cuttings and fluids pass through the solids control system. The basic solids control system for a weighted mud consists of a shale shaker, a desander, and a desilter. Figure VIII-1 is a flow diagram for a typical solids control system. The following paragraphs describe the components of the system.[1]

Shaleshakers are mechanical devices consisting of: a mud box (designed to evenly distribute the mud flow onto the screen surface), a vibrating assembly and deck, and a stationary bed which diverts the screened drilling fluid (underflow) to the mud tank system. Shaleshakers are designed to remove drill solids that are 74 microns and larger. The parameters that affect the performance of a shaleshaker are:

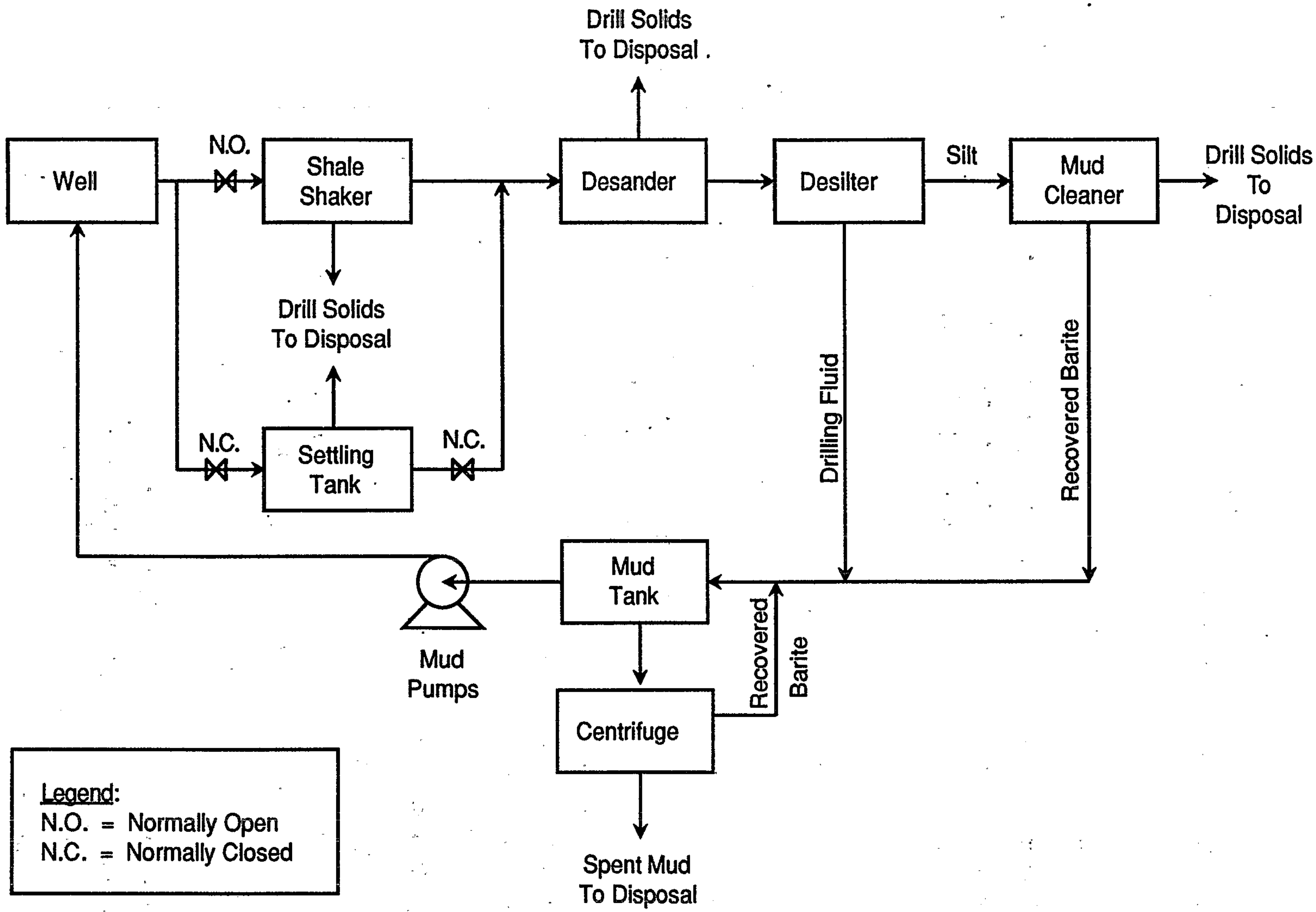

Figure VIII-1
Typical Solids Control System for Drilling Fluids and Drill Cuttings

shaker screen type and size, gravity force generated by the shaker motion, drilling fluid properties, and solids loading.

The desander is a hydrocyclone capable of removing sand-size particles greater than 44 microns by centrifugal force. Drilling fluids containing a high percentage of formation sands are believed to cause excessive weight and viscosity problems.

The desilter is a hydrocyclone capable of removing silt-size particles greater than 8 microns by centrifugal force. Drilling fluids containing a high percentage of fine silts are believed to promote side wall sticking.

A mud cleaner is a desilter combined with vibrating screens so that the underflow solids discharge can be screened before being discarded. This is necessary for weighted muds because a high percentage of barite is discharged in the underflow (and out of the mud circulation system) since barite can have particle sizes greater than 10 microns. Typically, a mesh screen with a 74 micron opening is used so that all solids smaller than 74 microns (barite) will pass through the screen and be returned to the mud system.

"Barite recovery" centrifuges are used to control mud viscosity by increasing the fine solids removal and barite recovery. Centrifuges are also used for secondary recovery of liquid and chemical that is normally lost to the reserve tank. This loss would occur in the jetting of whole mud, the dumping of sand traps, and the discard from components of the solids control equipment.

The "barite recovery" centrifuges are typically used for weighted muds with densities ranging from 12 to 19 pounds per gallon. This centrifuge removes the ultrafine and colloidal size solids that cause high viscosity in a weighted mud system. The barite separates from the mud in the underflow while the water, chemicals, bentonite, and fine drill solids are separated though the overflow.

Secondary recovery centrifuges recover the liquid and chemicals that are normally lost to the reserve tank with the cuttings. Secondary recovery centrifuges can be used to treat the underflows of the desander and desilter, and the overflow of the barite recovery centrifuge.

3.0 DRILL CUTTINGS VOLUMES

The volume of drill cuttings generated depends on the depth and diameter of the well drilled. Drill solids are continuously removed via the solids control equipment during drilling. The greatest volumes of drill cuttings are generated during the initial stages of drilling when the borehole diameter is large. Continuous and intermittent discharges are normal occurrences in the operation of solids control equipment. Such discharges occur for periods from less than 1 hour to 24 hours per day, depending on the type of operation and well conditions.

The volume of drill cuttings generated also depends on the type of formation being drilled, the type of bit, and the type of drilling fluid. Soft formations are more susceptible to borehole washout than hard formations. The type of drilling fluid used will minimize borehole washout and shale sloughing. The type of drill bit determines the characteristics of the cuttings (particle size). Depending on the formation and the drilling characteristics, the total drill solids generated will be at least equal to the borehole volume and sometimes several times the borehole diameter.

A report by the Offshore Operators Committee presented data from two drilling projects in the Gulf of Mexico. The report presents drilling data from a 10,000 foot well and a 18,000 foot well. Table VII-1 in Section VII.3 presents volumes of drill cuttings generated for both wells. The cuttings volumes do not equal the hole volume because approximately 50 percent of the cuttings were assumed to be dispersed in the drilling fluid.[2]

4.0 DRILL CUTTINGS CHARACTERISTICS

Drill cuttings themselves are inert solids from the formation. However, drill cuttings discharges also contain drilling fluids that have adhered to the cuttings. The composition of drill cuttings discharges is directly dependent upon the fluid used. Cuttings associated with oil-based drilling fluids or from petroleum bearing formations will contain trace amounts of hydrocarbons. Hydrocarbons adsorb on the surface of drill solid particles and resist removal by washing operations. The volume of the mud adhering to the discharged cuttings can vary considerably depending on the formation being drilled and the cutting's particle size distribution. A general rule of thumb is that five percent (5%) mud (by volume) is associated with the cuttings.[3] Data from a drilling project in the OCS off southern California indicate that the cuttings discharges from the solids control equipment were comprised of 96 percent cuttings and 4 percent adhered drilling fluids.[4]

5.0 CONTROL AND TREATMENT TECHNOLOGY

Pollutant type and waste management practices for drill cuttings are entirely related to the drilling fluid used. Drill cuttings associated with an oil-based drilling fluid are contaminated with hydrocarbons (diesel or mineral oil). Cuttings associated with a low-toxicity water-based drilling fluid are considered to have toxicity similar to the drilling fluids.

5.1 BPT TECHNOLOGY

The BPT limitations for drill cuttings prohibit the discharge of free oil based upon using the presence of a visible sheen upon the receiving water as a test for compliance. Cuttings that create sheens are from drilling operations that: use oils for lubricity or spotting purposes; or use oil-based muds. Cuttings that contain free oil are either collected and transported to shore for disposal or sufficiently washed to remove free oil prior to discharge. Cuttings that do not create a sheen can be discharged to the surface waters.

Cuttings washing technology is a mechanical separation process. The cuttings are processed in a series of tanks, screens, and cyclones which separates the oil from the solids. Detergents are often used to enhance separation. In 1983, EPA evaluated several cuttings washing systems. The evaluation indicated that these systems can consistently reduce the oil content in cuttings to a range of 5 to 10 percent. The evaluation also indicated that the most common method of compliance for cuttings containing some known quantity of oil is onshore disposal.[5]

5.2 ADDITIONAL TECHNOLOGIES

EPA evaluated several additional technologies for appropriateness as a basis for BCT, BAT, and NSPS limitations. These technologies are summarized in the following sections.

5.2.1 Onshore Treatment and/or Disposal

Drill cuttings which are unable to comply with the NPDES permit limitations are typically hauled to shore for treatment and/or disposal. EPA determined that transporting drilling wastes to shore is currently practiced by industry and is both technologically and economically feasible.

A more detailed discussion of available land disposal methods for drilling wastes can be found in Section VII.

5.2.2 Mechanical Processes

In 1988, EPA presented an evaluation of mechanical cuttings washing systems. Vendor performance data indicated that achieving a residual oil level of less than 10 percent by weight is achievable by mechanical washing systems.[5,6] Table VIII-1 presents the technology type, equipment features, capacity, and performance for each of the systems studied.

The mechanical process separates drilling fluids from the cuttings either by high pressure sprays or by immersion in an agitated tank. The wash solution may be seawater or a solvent and detergents are often used to enhance separation. The mixture of drill cuttings, drilling fluid, and wash solution is screened for separation of solids and liquids. Liquids carrying fine solids are processed in desilters or centrifuges for further separation. The separated oil and additives are recycled back to the mud system, wash solutions are recycled, and the cuttings are discharged. Cleaned cuttings are discharged either directly overboard or through a flume below the water surface. In a flume system, cuttings are discharged below the surface of the water through the inner pipe of a double pipe system. Additional residual oil remaining on the cuttings may separate and rise through the annulus to the seawater level. A submersible pump recovers this separated oil and cuttings drop to the ocean floor.

Mechanical systems offered by vendors employ various combinations of the above-mentioned techniques. The capacity of these systems varies from 1.25 to 12 tons per hour. Space requirements vary between the different systems. Some of the subsections are modular and can be made to fit available space. Performance of a cuttings washer system is reported in terms of the residual oil remaining on the cuttings.

5.2.3 Thermal Distillation/Oxidation

A detailed discussion of the thermal distillation and oxidation technologies evaluated is presented in Section VII-5.2.7.

5.2.4 Solvent Extraction

A detailed discussion of the solvent extraction technology evaluated is presented in Section VII-5.2.8.

TABLE VIII-1

CUTTINGS WASHER TECHNOLOGY[6]

Company	Type of Washing Technology	Features	Capacity of Units	Residual Oil on Cuttings	Remarks
A	Mechanical	Continuous process; Immersion Method Seawater Wash: surfactant, 2x800 gal tanks, screen, centrifuge for fine particles	125 ft^3/hr	10% by volume	
B	(a) Mechanical	Single stage centrifuge system for mineral oil based muds: agitated tank, pump, centrifuge	5 tons/hr	7-10% w/w of dry cuttings	Used in Norwegian North Sea
	(b) Mechanical	Two stage centrifuge system for diesel oil based muds: wash tank, dispersant and polymer, vibra-feeder, centrifuge, catch tank, pump, centrifuge	5-12 tons/hr	3-8.5% w/w of dry cuttings	Used in U.K. North Sea
C	(a) Mechanical	Seawater spray, flume discharge, oil recovery by submerged pumps		< 6% by weight for mineral oil based mud	Used in U.K. North Sea
	(b) Mechanical	Agitated holding tank, no detergent, pump, centrifuge	7,700 lb/hr	<10% by weight	Used in U.S Gulf Coast
D	Mechanical	Salt water spray, inclined Trommel for solid-liquid separation	120 ft^3/hr		Used in Gulf of Mexico, and off coast of California
E	Mechanical	Diesel wash, screen for coarse particles, centrifuge for fine particles, sluiced to seawater	12,500 lb/hr (peak 25,000 lb/hr)	<10% , with free oil 100-500 ppm	Operated in North Sea
F	Mechanical	Oil based wash solution, spray, screen, desilting cones, oil-water separator, flume discharge			
G	Mechanical	Wash tank, dispersant, solid shaker, desilter, oil-water separator	3-4 ft^3/hr	2%	None
H	Mechanical	Mixing tank, cleaning chemicals, oil and sludge separation, high pressure jets		6-7% by volume	None

5.2.5 Grinding/Reinjection

A detailed discussion of the drill waste grinding and injection technology is presented in Section VII-5.2.9.

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SECTION IX

PRODUCED WATER— CHARACTERIZATION, CONTROL AND TREATMENT TECHNOLOGIES

1.0 INTRODUCTION

The first part of this section describes the sources, volumes, and characteristics of produced water from offshore oil and gas production activities. The second part of this section describes the treatment technologies available to reduce the quantities of pollutants in produced water discharged to surface water.

2.0 PRODUCED WATER SOURCES

Produced water is the total water generated from the oil and gas extraction process. Produced water includes: the formation water brought to surface with the oil and gas, the injection water used for secondary oil recovery that has broken through the formation, and various well treatment chemicals added during production and the oil/water separation process.

Formation water, which comprises the bulk of produced water, is found in the same rock formation as the crude oil and gas. Formation water is classified as meteoric, connate, or mixed. Meteoric water comes from rainwater that percolates through bedding planes and permeable layers. Connate water (seawater in which marine sediments were originally deposited) contains chlorides, mainly sodium chloride (NaCl), and dissolved solids in concentrations many times greater than common seawater. Mixed water is characterized by both a high chloride and sulfate-carbonate-bicarbonate content, which suggests multiple origins.

3.0 PRODUCED WATER VOLUMES

Produced water is the highest volume waste source in the offshore oil and gas industry. The volume of wastewater generated by this industry is somewhat unique in comparison with industries in which wastewater generation is directly related to the quantity or quality of raw materials processed. By contrast, produced water can constitute from 2 percent to 98 percent of the gross fluid production at a given platform. In general, produced water volume is small during the initial production phase when hydrocarbon production is the greatest, and increases as the formation approaches hydrocarbon depletion.

Produced water volumes are much greater for structures producing oil or a combination of both oil and gas as compared to gas-only platforms. The volume of produced water at a given platform is a site-specific phenomenon. In some instances, no formation water is encountered while in others there is an excessive amount of formation water encountered at the start of production.

According to Walk, Haydel and Associates (1984), the average produced water discharge rate from an offshore platform is usually less than 1,800 barrels per day (bbl/day), whereas discharges from large treatment facilities handling water from many platforms may be as high as 157,000 bbl/day.[1] Produced water volumes, treatment systems information, and hydrocarbon production from platforms sampled in EPA's 30-facility study are presented in Table IX-1. Details of this study are discussed in Section IX.4.1. As can be seen from the table, produced water volumes range from 2 to 150,000 bbl/day.

In 1982, EPA conducted a sampling program located offshore from California to characterize produced water from this region. Three facilities were selected to represent oil production in the Santa Barbara Channel. The three facilities are as follows: the Carpinteria onshore treatment facility - processing fluids from several platforms located in the summerland field, the Ellwood Facility - processing fluid from platform Hope, and an offshore platform located in federal waters. The production fluid characteristics of these three facilities are presented in Table IX-2.

In 1982, sampling of produced water in Alaska was conducted at two major oil and gas producing fields: coastal facilities in Cook Inlet (Kenai Peninsula), and at an onshore facility in Prudhoe Bay on the North Slope. The production fluid characteristics of these facilities is presented in Table IX-3.

To analyze the cost and impact of effluent guidelines regulations, EPA developed average annual and peak produced water volumes for existing and future model projects. The estimates of produced water generation rates were developed using the Minerals Management Service (MMS) Platform Inspection Complex/Structure database. The methodologies used to develop the produced volumes are presented in the *Economic Impact Analysis for the Final Rule*. Regional average annual produced water generation rates for existing facilities (BAT) and future projected facilities (NSPS) are presented in Tables IX-4 through IX-7. The generation rates are based on the current and projected model platforms presented in Appendix 1.

TABLE IX-1

CHARACTERISTICS OF PLATFORMS SELECTED FOR THE 30 PLATFORM STUDY[2]

No.	Platform	Company	Oil/Condensate (bbl/day)	Gas (MMCF/day)	Brine (bbl/day)	Treatment (1)
1	EC 33A	Conoco	76.6	15.2	62	OS and DISS
2	EC 14CF	Mobil	807	13.1	2,005	
3	V 119D	Conoco	890	3.4	2,817	OS and DISP
4	V 255A	Shell	950	14	1,298	DISP
5	SMI 23B	Gulf	228	13.8	495	OS and DISP
6	V 39D	Shell	395	38	634	OS and DISP
7	SMI 6A	Exxon	250	0.2	625	
8	EI 57A-E	Marathon	1,200	150	500-2,000	
9	SMI 115A	Shell	750	45	1,200	OS and DISP
10	EI 120CF	Mobil	3,500	5	2,000	OS and DISP
11	SMI 130B	Shell	21,500	63	9,733	OS and DISP
12	EI 208B	Conoco	1,501	0.2	350	DISP
13	EI 18CF	Shell	2,000	30	22,000	OS and DISS
14	EI 238A	Gulf	40	6	2	DISP
15	EI 296B	Placid	1,500	100	1,470	OS and DISS
16	SS 107(S94)	Chevron	501	1.2	4,610	DISP
17	SS 107(S93)	Chevron	2,875	5.0	12,500	DISP
18	SS 219A	Amoco	3,000	7	800-1,000	
19	ST 177	Gulf	2,800	10	1,072	DISP
20	BM 2C	Shell	10,794	11.7	6,590	OS and DISP
21	BDC CF5	Texaco	873	2.8	11,028	OS and DISP
22	ST 135	Gulf	6,000	18	8,400	DISP
23	WD 90A	Amoco	2,244	10.7	15,000	OS and DISP
24	WD 45E	Conoco	745	2.3	1,578	DISP
25	WD 70I	Conoco	5,273	15.5	10,721	DISP
26	GIB DB600	Texaco	554	0.1	3,796	OS and DISP
27	WD 105C	Shell	2,091	12.1	7,532	DISP
28	SP 62A	Shell	1,800	1.3	3,100	OS and DISS
29	SP 24/27	Shell	24,000	40	150,000	OS and DISP
30	SP 65B	Shell	5,000	8	3,000	OS and DISP

(1) OS = Oil Skimming; DISS = Dissolved Gas Flotation; DISP = Dispersed Gas Flotation

TABLE IX-2

CHARACTERISTICS OF FACILITIES SELECTED FOR THE CALIFORNIA SAMPLING PROGRAM[3]

Facility	Produced Water Volume (bbl)	Oil (bbl)	Gas (MCF)	Treatment
Ellwood Facility	1,230	9,200	NR	Filtration, reinjection (100% reinjection of produced water)
Carpinteria Facility	14,000	6,400	NR	Oil skimming, flotation (100% overboard discharge of produced water)
Offshore Platform	25,000	17,000	NR	Flotation, filtration, reinjection (20% reinjection and 80% overboard discharge of produced water)

NR: NOT REPORTED

TABLE IX-3

CHARACTERISTICS OF FACILITIES SELECTED FOR THE ALASKA SAMPLING PROGRAM[3]

Facility	Produced Water Volume (bbl)	Oil (bbl)	Gas (MCF)	Treatment
Coastal Cook Inlet	18,350	1,300	410	Oil skimming, reinjection (59% reinjected and 41% discharged overboard)
Onshore Cook Inlet	6,600	12,500	-	Oil skimming, flotation, reinjection (33% reinjected and 67% discharged overboard)
Prudhoe Bay Oil Field	13,000	92,100	136,500	Reinjection (100%)

TABLE IX-4

BAT PRODUCED WATER GENERATION RATES - 4 MILE PROFILE
(Millions of Barrels per Year)

Region	Within 4 Miles	Beyond 4 Miles	Total
Gulf of Mexico	57,075	846,307	903,383
Pacific	81,773	131,098	212,870
Alaska	0	0	0
Atlantic	0	0	0
Total	138,848	977,405	1,116,253

TABLE IX-5

BAT PRODUCED WATER GENERATION RATES - 3 MILE PROFILE
(Millions of Barrels per Year)

Region	Within 3 Miles	Beyond 3 Miles	Total
Gulf of Mexico	14,705	888,678	903,383
Pacific	58,409	154,461	212,870
Alaska	0	0	0
Atlantic	0	0	0
Total	73,114	1,043,139	1,116,253

TABLE IX-6

NSPS PRODUCED WATER GENERATION RATES - 3 MILE PROFILE
(Millions of Barrels per Year)

Region	Within 3 Miles	Beyond 3 Miles	Total
Gulf of Mexico	31,761	345,482	377,243
Pacific	0	0	0
Alaska	35,532	9,287	44,819
Atlanta	0	0	0
Total	67,293	354,769	422,062

TABLE IX-7

NSPS PRODUCED WATER GENERATION RATES - 4 MILE PROFILE
(Millions of Barrels per Year)

Region	Within 4 Miles	Beyond 4 Miles	Total
Gulf of Mexico	37,421	339,822	377,243
Pacific	0	0	0
Alaska	35,532	9,287	44,819
Atlanta	0	0	0
Total	72,953	349,109	422,062

4.0 PRODUCED WATER COMPOSITION

In 1980, very few data existed on the composition of produced water other than conventional parameters. In 1981, EPA embarked on a systematic effluent sampling study to identify and quantify the characteristics of produced water with regard to priority toxic pollutants. Sampling programs were conducted in the three major offshore producing areas of the United States, i.e., the Gulf of Mexico, California, and Alaska. Separate discussions on the characteristics of produced water are presented for each of the regional offshore producing area

Since the 1985 proposal, no new EPA field sampling data have been acquired relating to the general character of untreated produced waters generated at offshore facilities. However, studies have been conducted on the characteristics of treated produced water either for BPT (permit limit) compliance or reinjection. In addition, statistical evaluations of data previously and newly submitted by the public have been conducted. The results of the studies and evaluations and how they affect the final effluent limitations guidelines are discussed in the following sections.

4.1 GULF OF MEXICO - 30 PLATFORM STUDY

During the period of October 9-30, 1981, thirty oil and gas production platforms located in the Gulf of Mexico were sampled to characterize the quantities of selected conventional, non-conventional, and priority pollutants present in produced water discharges. Overall, 79 individual samples were collected and analyzed. Twenty of the 79 samples collected were obtained from the influent to the treatment systems, while the remaining 59 samples were treated effluent samples. Table IX-8 presents the overall summary of occurrence of the organic priority pollutants detected in the 59 samples of effluents. As can be seen from this table, benzene, ethylbenzene, naphthalene, phenol, toluene, 2,4-dimethylphenol, and bis-(2-ethylhexyl)phthalate were observed in 80 percent or more of the effluent samples analyzed. An additional 15 organic compounds were detected far less frequently. The occurrence for these parameters ranged from 2 percent to 32 percent of the effluent samples analyzed. Many were either at or just above the detection limit.

TABLE IX-8

PERCENT OCCURRENCE OF ORGANICS FOR TREATED EFFLUENT SAMPLES 30 PLATFORM STUDY[34]

Parameter (1)	Number of Valid Determinations (2)	Number of Times Detected	Percent of Times Detected
Benzene	59	59	100%
Ethylbenzene	59	59	100%
Naphthalene	59	59	100%
Phenol	58	58	100%
Toluene	59	59	100%
2,4-Dimethylphenol	56	52	93%
Bis(2-ethylhexyl)phthalate	59	47	80%
Di-n-butyl phthalate	59	19	32%
Fluorene	59	13	22%
Diethyl phthalate	59	12	20%
Anthracene	29	3	10%
Acenaphthene	59	4	7%
Benzo(a)pyrene	59	3	5%
p-Chloro-m-cresol	59	1	2%
Dibenzo(a,h)anthracene	59	1	2%
Chlorobenzene	59	1	2%
Di-n-octyl phthalate	59	1	2%
3,4-Benzofluoranthene	59	1	2%
11,12-Benzofluoranthene	59	1	2%
Pentachlorophenol	59	1	2%
1,1-Dichloroethane	59	1	2%
Bis(2-chloroethyl)ether	59	1	2%

(1) - Pollutants not listed were not detected in any of the 59 effluent samples.
(2) - Number of samples which yielded valid analytical results.

The 30-platform data were used to support the proposed 1985 effluent limitation guidelines. For the 1991 proposal, EPA recalculated the data to reflect updated statistical procedures.[4] Specific reasons foı the reanalysis were:

- Concentration values for metals were previously calculated without reference to detection limits. The values reported in the analysis treats sample values reported below the detection limit to be zero as shown in Table IX-9.

- Duplicates were previously treated as individual samples. However, distinctions should have been made where "duplicate" samples are those split at the sample site and "replicate" samples are those split at the lab. For the reanalysis, where duplicate samples were considered, the value for an independent sample is the arithmetic average of the values for each duplicate. Furthermore, the value for a duplicate, or an independent sample that does not have a duplicate, is the arithmetic average of the replicate analyses if replicate analyses were performed.

TABLE IX-9

POLLUTANT CONCENTRATIONS IN BPT TREATED PRODUCED WATER FROM THE THIRTY PLATFORM STUDY[4,34]

Pollutant Parameter	March 1991 BPT Effluent
Oil & Grease	89.8 mg/l
TSS	67.5 mg/l
Priority Organic Pollutants	
Benzene	1,823.00 μg/l
Bis(2-ethylhexyl)phthalate	101.00 μg/l
Ethylbenzene	505.00 μg/l
Naphthalene	138.00 μg/l
Phenol	954.00 μg/l
Toluene	1,545.00 μg/l
2,4-Dimethylphenol	14.40 μg/l
Priority Metal Pollutants	
Cadmium	29.35 μg/l
Copper	183.42 μg/l
Lead	350.57 μg/l
Nickel	142.64 μg/l
Silver	59.19 μg/l
Zinc	2,360.00 μg/l

Table IX-9 presents the recalculated pollutant concentrations from the 30-platform study used to represent baseline effluent characteristics for priority pollutants achievable by BPT technology as presented in the March 13, 1991 proposal. Appendix 2 Tables A2-1, A2-2, and A2-3 present the data from this study.

4.2 CALIFORNIA SAMPLING PROGRAM

Table IX-10 presents the analytical data from the sampling program conducted in California in 1982. Statistical analyses from the Three Facility Study were conducted to assess detection rates of organic and metal pollutants and to generate facility-specific descriptive statistics for total suspended solids (TSS), oil and grease (O&G), and organic and metal pollutants in both gas flotation and granular media filtration effluent produced water. Tables IX-11 and IX-12 present analytical data from the Three Facility Study. Gas flotation effluent aggregate estimates used data from only two facilities, both located off California. The third facility is in New Mexico and does not utilize gas flotation in its produced water treatment process. Appendix 2 presents the analytical data from the three facility study.

TABLE IX-10

AVERAGE EFFLUENT COMPOSITION OBTAINED FROM THE 1982 CALIFORNIA SAMPLING PROGRAM[3]

Parameter	Pollutant Concentration		
	Ellwood Facility	Carpinteria Facility	Offshore Facility
Oil and Grease (mg/l)	NA	5	NA
Organic Priority Pollutants:			
Benzene (μg/l)	4,000	1,463	286
Ethylbenzene (μg/l)	348	148	140
Toluene (μg/l)	2,940	2,750	544
Phenol (μg/l)	1,046	973	19
2,4-Dimethylphenol (μg/l)	213	772	189
Naphthalene (μg/l)	84	86	127
Bis(2-ethylhexyl)phthalate (μg/l)	< 10	ND	ND
Priority Metal Pollutants:			
Copper (μg/l)	165	109	198
Lead (μg/l)	113	ND	77
Zinc (μg/l)	220	46	78
Non-conventionals:			
TDS (mg/l)	NA	22,700	NA
Chloride (mg/l)	NA	10,500	NA

NA - Not Analyzed
ND - Not Detected

TABLE IX-11

PRIORITY POLLUTANT DETECTION RATES IN FILTER TREATED PRODUCED WATER FROM THE THREE-FACILITY STUDY[5]

Parameter	Average Detection Limit (μg/l)	Shell - Beta Complex		Thums - Long Beach		Conoco, Hobbs, NM	
		Number Detects	Detect Rate	Number Detects	Detect Rate	Number Detects	Detect Rate
Organic Pollutants:							
Benzene	1,000	4	100%	4	100%	4	100%
Benzoic acid	50	1	25%	0	0%	2	50%
Ethylbenzene	1,000	4	100%	4	100%	4	100%
m-Xylene	10	4	100%	3	75%	4	100%
o,p-Xylene	55	3	75%	0	0%	4	100%
o-Cresol	10	2	50%	0	0%	3	75%
p-Cresol	10	4	100%	1	33%	3	75%
Phenol	10	4	100%	0	0%	3	75%
Toluene	1,000	4	100%	4	100%	4	100%
2-Butanone	275	4	100%	1	25%	0	0
Naphthalene	10	4	100%	3	100%	3	75%
2-Methylnaphthalene	10	4	100%	0	0%	3	75%
2-Propanone	275	4	100%	3	75%	1	25%
2,4-Dimethylphenol	10	2	50%	0	0%	3	75%
Bis(2-ethylhexyl)phthalate	10	0	0%	0	0%	0	0
Priority Metal Pollutants:							
Aluminum	35	4	100%	4	100%	1	25%
Antimony	31	1	25%	0	0%	2	50%
Arsenic	17	0	0%	1	25%	4	100%
Boron	10	4	100%	4	100%	4	100%
Barium	2	4	100%	4	100%	4	100%
Cadmium	4	0	0%	0	0%	0	0
Copper	6	1	25%	4	100%	2	50%
Iron	12	4	100%	4	100%	4	100%
Magnesium	46	4	100%	4	100%	4	100%
Manganese	2	4	100%	4	100%	4	100%
Nickel	30	0	0%	0	0%	0	0
Silver	7	0	0%	0	0%	0	0
Titanium	3	2	50%	3	75%	4	100%
Yttrium	2	2	50%	2	50%	4	100%
Zinc	14	4	100%	4	100%	4	100%

TABLE IX-12

PRODUCED WATER POLLUTANT CONCENTRATIONS IN FILTER INFLUENT FROM THREE FACILITY STUDY[5]

Pollutant Parameter	Concentrations (μg/l)								
	Shell - Beta Complex			Thums - Long Beach			Conoco, Hobbs, NM		
	MIN*	MAX*	MED*	MIN*	MAX*	MED*	MIN*	MAX*	MED*
Oil & Grease	43.50	56.50	50.15	13.14	24.42	20.75	25.87	41.83	34.54
TSS	13.38	16.97	13.94	16.24	33.51	23.63	53.78	74.72	64.18
Organic Pollutants:									
Benzene	949.45	1,073.17	971.06	43.57	56.7	54.6	8,833.8	9,135.6	9,031.65
Benzoic acid	50	633.77	50	NR	NR	NR	50	2,431.15	976.56
Ethylbenzene	232.51	322.97	256.73	19.24	27.33	24.18	950.95	1,039.1	1,023.1
m-Xylene	102.66	123.32	112.24	10	17.02	12.99	279.87	317.7	288.63
o,p-Xylene	21.21	100.00	25.09	NR	NR	NR	138.81	157.35	142.87
o-Cresol	10	29.53	14.10	NR	NR	NR	10	158.15	134.35
p-Cresol	115.12	151.11	117.82	10	36.11	10	10	551.38	445.06
Phenol	116.79	188.27	162.11	NR	NR	NR	10	611.68	444.39
Toluene	1,263.0	1,292.5	1,330.02	67.18	85.68	84.92	5,081.3	5,635.2	5,250.05
2-Butanone	601.23	1,493.6	1,380.5	50	65.84	50	NR	NR	NR
Naphthalene	66.34	76.0	72.17	14.99	21.53	18.94	10	57.74	50.54
2-Methylnaphthalene	12.18	15.35	12.93	NR	NR	NR	10	16.11	14.89
2-Propanone	941.64	1,237.6	1,135.4	50	144.7	86.3	500	628.17	500
2,4-Dimethylphenol	10	286.5	123.1	NR	NR	NR	10	227.46	173.29
Priority Metal Pollutants:									
Aluminum	56	103	71	53	145	136	35	43	35
Antimony	4	40	32	NR	NR	NR	40	70	68
Arsenic	NR	NR	NR	2	31	20	33	363	220
Boron	29,300	35,400	31,875	36,900	39,800	38,100	6,710	7,080	6,760
Barium	64,600	67,400	65,770	39,300	47,600	41,850	48	51	50
Cadmium	NR	NR	NR	NR	NR	NR	NR	NR	NR
Copper	6	111	6	35	153	75	6	146	12
Iron	657	880	689	2,420	16,000	5,915	535	800	668
Magnesium	172,000	189,000	175,250	318,000	350,000	321,522	415,000	467,000	445,000
Manganese	134	145	140	160	364	193	88	93	91
Nickel	NR	NR	NR	NR	NR	NR	NR	NR	NR
Silver	NR	NR	NR	NR	NR	NR	NR	NR	NR
Titanium	3	50	3	3	7	5	10	14	12
Yttrium	2	3	3	2	3	2	6	9	8
Zinc	37	55	46	61	96	65	16	34	18

*Pollutant Concentration "Minimum Level" Values were Substituted for Non-detect Samples
NR=Not Reported

4.3 ALASKA SAMPLING PROGRAM

Table IX-13 presents the analytical results obtained from the sampling program conducted in Alaska in 1982. A comprehensive Cook Inlet Discharge Monitoring Study was conducted by Region 10 to investigate oil and gas extraction point discharges.[6] Produced water discharges from production facilities in Cook Inlet (coastal subcategory) were sampled and analyzed for one year, September 1988 through August 1989. Samples were collected from two oil platforms and one natural gas platform, all of which discharge to the surface waters, and also from three shore-based central treatment facilities. Table IX-14 presents averages of effluent concentrations from these six facilities. Appendix 2 presents the data from this study.

TABLE IX-13

AVERAGE EFFLUENT CONCENTRATIONS OBTAINED FROM THE 1982 ALASKA SAMPLING PROGRAM[3]

Parameter	Coastal Cook Inlet	Onshore Cook Inlet	Prudhoe Bay Oil Field
Oil and Grease (mg/l)	17	15	10
Organic Priority Pollutants:			
Benzene (μg/l)	7,375	7,240	1,370
Ethylbenzene (μg/l)	345	170	900
Toluene (μg/l)	3,025	2,805	9,630
Phenol (μg/l)	1,810	1,683	3,490
2,4-Dimethylphenol (μg/l)	438	420	830
Naphthalene (μg/l)	359	330	595
Bis(2-ethylhexyl)phthalate (μg/l)	176	80	228
Priority Metal Pollutants:			
Copper (μg/l)	55	55	-
Mercury (μg/l)	3	3	3
Zinc (μg/l)	1,750	21	ND
Non-Conventionals:			
TDS (mg/l)	24,570	25,880	19,800
Chloride (mg/l)	12,200	13,000	10,220

ND - Not detected

TABLE IX-14

AVERAGE EFFLUENT CONCENTRATIONS FROM PRODUCED WATER IN COOK INLET DMR DATA[6]

Parameter	Concentration
Oil and Grease (mg/l)	30.3
Priority Organic Pollutants:	
Benzene (μg/l)	7,452
Toluene (μg/l)	3,326
Ethylbenzene (μg/l)	311
Phenol (μg/l)	825
Naphthalene (μg/l)	1,150
2,4-Dimethylphenol (μg/l)	293
Bis(2-ethylhexyl)phthalate (μg/l)	-
Priority Metal Pollutant:	719
Zinc (μg/l)	
Non-conventional Pollutants:	389.0
TOC (mg/l)	

4.4 STATISTICAL ANALYSIS OF EPA/API PRODUCED WATER EXPANDED DATASET

For the final rule, EPA recalculated the BPT baseline effluent characteristics based on several industry and EPA databases. Table IX-15 presents the BPT effluent data.

TABLE IX-15

1992 BPT EFFLUENT DATA[7]

Pollutant Parameter	Recalculated BPT Effluent
Oil and Grease	25 mg/l
TSS	67.5 mg/l
Priority and Non-conventional Organic Pollutants:	
Anthracene	18.51 µg/l
Benzene	2,978.69 µg/l
Benzo(a)pyrene	11.61 µg/l
Chlorobenzene	19.47 µg/l
Di-n-butylphthalate	16.08 µg/l
Ethylbenzene	323.62 µg/l
n-Alkanes	1,641.50 µg/l
Naphthalene	243.58 µg/l
p-Chloro-m-cresol	25.24 µg/l
Phenol	1,538.28 µg/l
Steranes	77.50 µg/l
Toluene	1,897.11 µg/l
Triterpanes	78.00 µg/l
Total xylenes	695.03 µg/l
2-Butanone	1,028.96 µg/l
2,4-Dimethylphenol	317.13 µg/l
Priority and Non-conventional Metal Pollutants:	
Aluminum	78.01 µg/l
Arsenic	114.19 µg/l
Barium	55,563.80 µg/l
Boron	25,740.25 µg/l
Cadmium	22.62 µg/l
Copper	444.66 µg/l
Iron	4,915.87 µg/l
Lead	195.09 µg/l
Manganese	115.87 µg/l
Nickel	1,705.46 µg/l
Titanium	7.00 µg/l
Zinc	1,190.13 µg/l
Radionuclides:	
Radium 226	2.2628×10^{-4} µg/l
Radium 228	2.7671×10^{-4} µg/l

5.0 CONTROL AND TREATMENT TECHNOLOGIES

Treatment processes for produced water are primarily designed to control oil and grease, priority pollutants, and total suspended solids. Currently, most NPDES permits allow the discharge of offshore produced water to surface, saline water bodies, subject to limitations only on the oil and grease content (BPT limitation).

5.1 BPT TECHNOLOGY

BPT effluent limitations restrict the oil and grease concentrations of produced water to a maximum of 72 mg/l for any one day, and to a thirty day average of 48 mg/l. BPT end-of-pipe treatment that can achieve this level of effluent quality consists of some, or all of the following technologies:

- Equalization (surge tank, skimmer tank)
- Solids removal desander (with or without sand washer)
- Chemical addition (feed pumps)
- Oil and/or solids removal
- Flotation
- Filters
- Plate coalescers
- Gravity separators
- Subsurface disposal (reinjection).

The separation of oil from produced water is directly related to the particle size of the oil droplets dispersed in the produced water. Oil is present in produced water in a range of particle sizes from molecular to droplet. Reducing the oil content of produced water involves removing three basic forms of oil: (1) large droplets of coalesceble oil, (2) small droplets of emulsified oil, and (3) dissolved oil. Produced water treatment processes are generally effective in removing most of the free oil. The removal efficiency and resultant effluent quality achieved by the treatment unit is dependent upon the influent flow, the influent concentrations of oil and grease and suspended solids, and the other types of compounds in the produced water. Examples of working ranges for some produced water treatment units are:

Unit	Sizes Removed
Flotation	above 10-20 microns
Parallel plate coalescers	above 30-40 microns
Proprietary (API) separators	above 6 microns
Skim tanks	above 15 microns

Smaller oil droplets are formed by the shear forces encountered in pumps, chokes, valves, and high flow rate pipelines. These droplets are stabilized (maintained as small droplets) by surface active agents, fine solids, and high static charges on the droplets.[8] Any operational change that promotes the formation of smaller droplets or the stabilization of small droplets through increased produced water flow velocities and/or increased pollutant loadings can result in poor oil and water separation. Operational changes affecting the performance of the produced water treatment system, referred to as upset conditions, can be caused by detergent washdowns in deck drainage entering the treatment unit, high flow volumes caused by heavy rainfall, and equipment failures.

End-of-pipe control technology for offshore treatment of produced water from oil and gas production consists of physical and/or chemical methods. The type of treatment system selected for a particular facility is dependent upon availability of platform space, waste characteristics, volumes, existing discharge limitations, and other site specific factors. Oil skimming with gravity separation and/or chemical treatment and gas flotation are widely used in the offshore industry because of space limitations on platforms. A description of the unit processes that may be used in the treatment scheme for produced water is presented in the following sections.

5.1.1 Equalization

Equalization dampens flow and pollutant concentration variation of wastewater prior to subsequent downstream treatment. By reducing the variability of the raw waste loading, equalization can significantly improve the performance of downstream unit processes by providing uniform hydraulic, organic, and solids loading rates. Increased treatment efficiency reduces effluent variability associated with slug raw waste loadings. Equalization is accomplished in a holding tank. The tank should be designed with sufficient retention time to dilute the effects of variable flow and concentrations on the treatment plant performance. Some oil and water separation will also take place in the equalization tank.

5.1.2 Solids Removal

The fluids produced with oil and gas may contain small amounts of sand or scale particles from the piping which must be removed from lines and vessels. Removal of these solids can be accomplished by blowdown, by cyclone separators (desanders), or during equipment cleanout. Desanders are not typically used in offshore operations to remove sand (and other particles) from produced water. The most common method of removing produced solids from the process equipment is during cleanout of the gravity separators which accumulate solids. Equipment cleanouts typically occur every three to five years. Additional information on produced sand generation rates and disposal practices is presented in Section X.

5.1.3 Gravity Separation

The simplest form of produced water treatment is gravity separation in horizontally or vertically configured tanks or pressure vessels. Gravity separators are sometimes called skim tanks, skim vessels, or water clarifiers. Gravity separators are designed with enough storage capacity to provide sufficient residence time for the oil and water to separate. Performance of these systems depends upon the characteristics of the oil, produced water, flow rates, and retention time. Gravity separation systems with large residence times are typically located onshore (and have limited application) on offshore platforms because of space and weight limitations. While a treatment system relying exclusively on gravity separation requires large tanks with long retention times, any treatment can benefit from even short periods of quiescent retention to allow for some oil and water separation and dampen surges in flow rate and oil loadings.

5.1.4 Parallel Plate Coalescers

Parallel plate coalescers are gravity separators which contain a pack of parallel, tilted plates arranged so that oil droplets passing through the pack need only rise a short distance before striking the underside of the plates. Guided by the tilted plate, the droplet then rises, coalescing with other droplets until it reaches the tip of the pack where channels are provided to carry the oil away. In their overall operation, parallel plate coalescers are similar to API gravity oil-water separators. The pack of parallel plates reduces the distance that oil droplets must rise in order to be separated; thus the unit is much more compact than an API separator. Suspended particles, which tend to sink, move down a short distance when they strike the upper surface of the plate; then they move down along the plate to the bottom of the unit where they are deposited as sludge and can be periodically removed. Particles may become attached (scale) to the plates' surfaces requiring periodic removal and cleaning of the plate pack.

Where stable emulsions are present, or where the oil droplets dispersed in the water are relatively small, parallel plate coalescers may not provide an effective oil-water separation.

5.1.5 Gas Flotation

Gas flotation units introduce small gas bubbles into the body of wastewater to be treated. As the bubbles rise through the liquid, they attach themselves to any oil droplet in their path, and the gas and oil rise to the surface where they are skimmed off as a froth.

The gas flotation methods currently available are generally divided into two groups: (1) dissolved-gas flotation (DGF) and (2) induced-gas flotation (IGF). The major difference between these methods are the techniques used to generate the gas bubbles and the size of the gas bubbles produced. In dissolved-gas flotation, the gas bubbles are generated by the precipitation of air (gas) from a super-saturated solution. In induced-gas flotation, gas bubbles are generated by mechanical shear or propellers, diffusion of gas through a porous media, or homogenization of a gas and liquid stream. The size of bubbles produced in dissolved gas flotation (average 10 to 100 microns in diameter) are an order of magnitude smaller than those generated in induced-gas flotation.[9]

Dissolved-gas flotation processes were at one time extensively used for the final treatment of produced oil field water.[10] Currently, the majority of the offshore oil production facilities use induced-gas flotation systems for treating their produced water before final disposal. Induced-gas flotation requires less space than dissolved gas systems, and thus IGF is the system of choice in the offshore industry. The 30 Platform Study's analysis of produced water effluents indicated that 23 of the 26 facilities with gas flotation were IGF.

Chemicals are commonly used to aid the flotation process. Chemicals function to create a surface or a structure that can easily absorb or entrap air bubbles. Inorganic chemicals, such as the aluminum or ferric salts and activated silica, can be used to bind the particulate matter and to create a structure that can easily entrap air bubbles. Various organic chemicals can be used to change the nature of either the air-liquid interface or the solid-liquid interface, or both. These compounds usually collect on the interface to bring about the desired changes.

The following sections provide further details about DGF and IGF systems.

5.1.5.1 Dissolved-gas Flotation

In dissolved-gas flotation, water is first saturated with air (gas) either under atmospheric or elevated pressures, then air is precipitated from the solution by either applying a vacuum (referred to as vacuum flotation) or an instantaneous reduction in system pressure (referred to as pressure flotation). Under the reduced air pressure, the air precipitates in the form of air bubbles which interact with the dispersed material and carry them to the surface of the liquid. Mechanical flight scrapers are then used to remove the floated material.

Since the solubility of air at atmospheric conditions is low and efficiency of the flotation process is directly proportional to the volume of gas released from solution within the flotation cell, the use of vacuum flotation is extremely limited. With the pressure flotation method, higher gas solubilities are possible because of the higher system pressures involved. As a result, larger volumes of gas are released within the flotation units following a drop in the system pressure resulting in greater overall process efficiency. In the following discussion, the term "gas flotation" refers to the process of pressure flotation.[9,11]

The major components of a conventional gas flotation unit include a centrifugal pump, a retention tank, and a flotation cell.[10,12] As the first step in the gas flotation process, gas is introduced into the influent stream at the suction end of a centrifugal pump discharging into a small retention tank. During this process, the gas is sheared into finely dispersed bubbles which remain in the solution for a short period of time (1 to 3 minutes retention time) in the retention tank. At this point the excess gas (undissolved air) is purged from the tank. From the retention tank, the saturated water passes through a backpressure regulator before entering the flotation unit. This regulator facilitates for the necessary instant pressure drop in the system and creates turbulence for proper dispersion of gas bubbles. Floc, which forms as air bubbles interact with the suspended material, is lifted to the surface of the flotation cell, where it is removed by mechanical skimmers. Suspended material which is not amendable to flotation is settled, concentrated and removed from the bottom of the flotation cell. Clean water is collected from the lower part of the cell where there is less turbulence.

5.1.5.2 Induced-gas Flotation

In a basic induced-gas flotation system (also referred to as dispersed-gas flotation), gas is drawn into the flotation cell either mechanically (mechanical-type) by an impeller or hydraulically (hydraulic-type) by an eductor into a cell containing the water. The introduced gas is then sheared into finely dispersed bubbles by a disperser or a rotating impeller. The dispersed gas is interacted with the suspended solid and liquid particles and floats them to the surface. A skimmer system is used to remove the floated solids generated by interaction of the air bubbles and dispersed material.

The more advanced induced-gas flotation units are generally multi-cell in design. This feature provides these systems with improved hydraulic characteristics due to reduced short-circuiting (as compared to a single-cell design) and sequential contaminant removal. For example, if each cell in a four-cell unit removes 60 percent of its receiving waste load, the overall removal performance is 97.5 percent; at 70 percent per unit, the overall efficiency of greater than 99 percent is achieved.[9]

Studies have shown that induced-gas systems produce bubbles that often reach 1,000 microns (1mm) in diameter. Bubbles from dissolved-gas flotation average between 70 to 90 microns in diameter and can get as small as 30 microns.[13] The larger gas bubbles often cause turbulence in the solution which could lead to breakdown of the floc, thus reducing the overall system efficiency. This type of problem has been remedied by proper modifications to existing systems or consideration in the new designs. Such consideration may include repositioning the diffuser nozzles so that the air is released in the vertical direction for maximum efficiency and minimum turbulence in the flotation tank.[11,13]

Some of the main advantages that have made IGF more popular for offshore use include: less stringent operation and maintenance requirements, lower comparative power requirements, and adaptability to existing facilities. In addition, because of the larger bubbles produced in this type of unit, interactions are much faster resulting in shorter required retention time and smaller units. Hence, less capital cost and space are required.[9,11,13]

Figure IX-1 presents a schematic drawing of a mechanical-type induced-air gas flotation unit.[14]

Mechanical-Type Induced Gas Flotation Systems - In this type of gas flotation system, a rotor with several blades rotates in the produced water creating a vortex. This creates a negative pressure which draws gas from the freeboard down a standpipe for dispersion in liquid. The gas is then sheared into minute bubbles as it passes through a disperser and therefore creates an intimate mixture of liquid and bubbles. The rotating action of the rotors also causes liquid and solids to circulate upward from the bottom of the cell and allows it to mix with the incoming waste stream and gas bubbles. The interaction of oil droplets and gas bubbles occurs in the flotation region of the tank.

A dispenser hood provides a baffling effect which maintains the skim region in a quiescent state. The rising of bubbles creates a surface flow towards the cell walls, where skimmer paddles are located. Skim rate is generally a factor of foam characteristics and unit size. Suspended solids that are amendable to flotation are also removed along with the oil.[11,15]

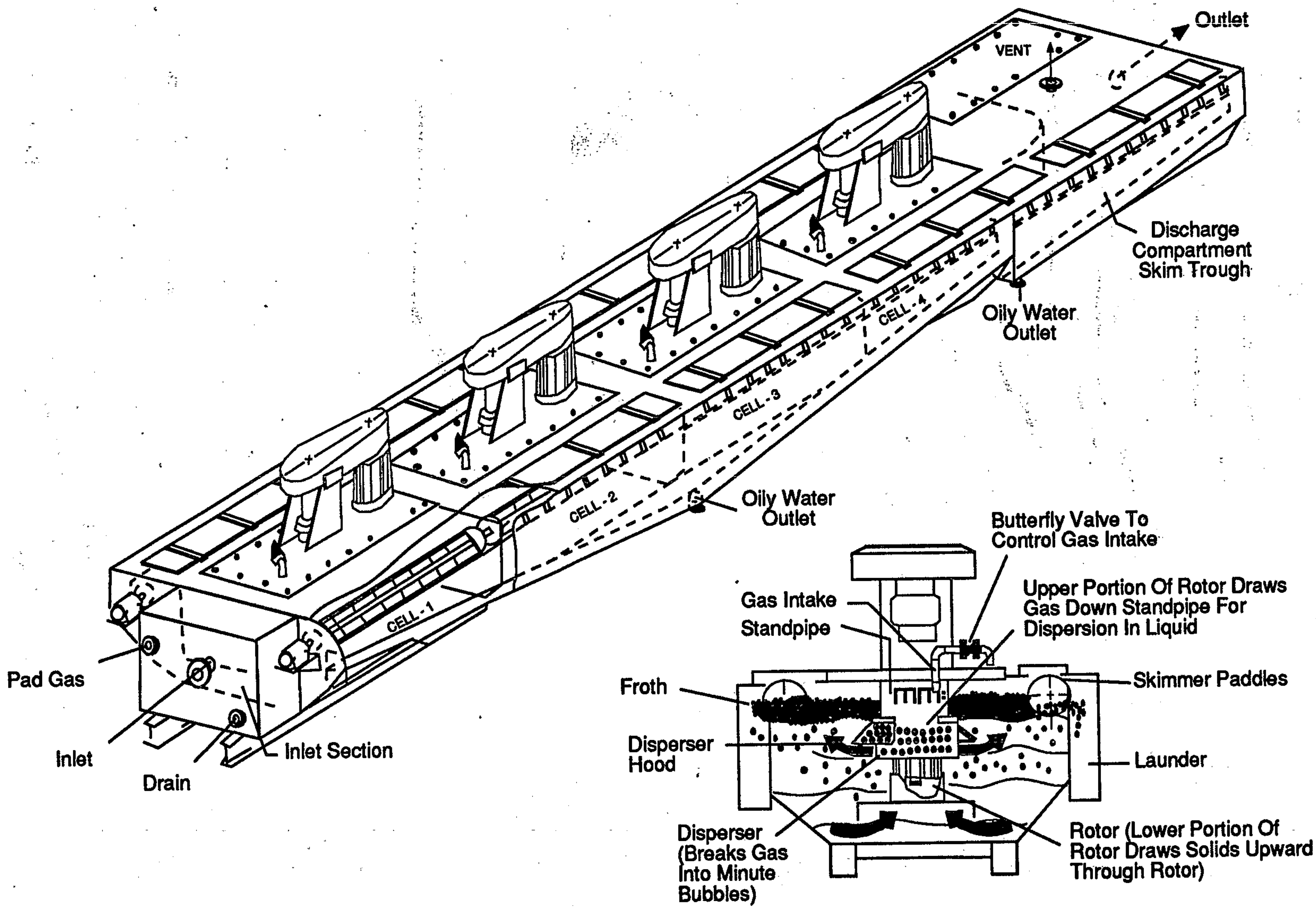

Figure IX-1
Dispersed Gas Floatation Unit[14]

The action of the rotor and dispenser generates relatively large bubbles (up to about 1000 microns in diameter). Since the size of the bubbles is larger than in dissolve-gas flotation units, greater gas flow is required by this type of unit to maintain a sufficient bubble population.[11]

Hydraulic-Type Induced Gas Flotation Systems - Hydraulic-type induced gas flotation units consist of a feedbox, a series of cells separated by underflow baffles, and a discharge box. A gas eductor is installed in each cell in a standpipe through which part of the cleaned discharge water is recycled back to the unit. Gas is drawn into this stand pipe as the result of the venturi effect created by the flow of the recycled water. The mixing of gas with the recycled water generates small bubbles which defuse and interact with the dispersed oil droplets in the water. Eductors are often installed at an angle to create a surface flow to the side where the skimmers and the skim trough are located. The flotation and skimming processes are similar to those in mechanical-type systems.[11]

The rate at which gas flows into an eductor is a function of recycle rate (eductor pressure), gas inlet orifice size, and any valve that may have been installed in the gas feed pipe. The gas flow rate and energy dissipation are the major factors in determining the size of bubbles produced. The recycle flow rate is generally controlled manually through control valves installed in the recycle line and between the recycle header and each eductor. The recycle rate is the most important control parameter for optimizing the performance of hydraulic-type systems. For example, as recycle rate increases, the gas rate increases, resulting in a decrease in the initial residence time. This allows for only partial treatment of the influent water and could result in short circuiting of the system.[11]

Hydraulic type units are generally less expensive, are lower in overall operating cost, and experience less downtime than other types of gas flotation systems. However, because the gas transfer per unit volume of water in this type of unit is significantly lower than in mechanical-type units, hydraulic-type units achieve lower removal efficiency than mechanical-type units.[11,16]

5.1.6 Chemical Treatment

The addition of chemicals to the wastewater stream is an effective means of increasing the efficiency of treatment systems. Chemicals are used to improve removal efficiencies in flotation units, plate coalescers, and gravity separation systems. The three basic types of chemicals that are used to enhance equipment removal efficiencies in wastewater treatment are:

<u>Surfactants</u>: Surfactants, also known as surface-active agents or foaming agents, are large organic molecules that are slightly soluble in water and cause foaming in wastewater treatment plants and in the surface waters into which the waste effluent is discharged. Surfactants tend to collect at the air-water interface. During aeration of wastewater, these compounds collect on the surface of the air bubbles creating a very stable foam.

<u>Coagulants</u>: Coagulating agents assist the formation of a floc and improve the settling characteristics of the suspended matter. The most common coagulating agents are aluminum sulfate (alum) and ferrous sulfate.

<u>Polyelectrolytes</u>: These chemicals are long chain, high molecular weight polymers used to bring about particle aggregation. Polyelectrolytes act as coagulants to lower the charge of the wastewater particles, and aid in the formation of interparticle bridging. Depending on whether their charge, when placed in water, is negative, positive, or neutral, these polyelectrolytes are classified as anionic, cationic, and nonionic, respectively.

Surface active agents and polyelectrolytes are the most commonly used chemicals in wastewater treatment processes. The chemicals are injected into the wastewater upstream of the treatment unit without pre-mixing. Serpentine pipes, existing piping arrangements, etc., induce enough turbulence to evenly disperse these chemicals into the water stream.

5.1.7 Skim Pile

A skim pile is a large diameter pipe attached to the platform extending below the surface of the water. Typical skim pile dimensions are a length of 70 meters and a diameter of one meter. Skim piles are vertical gravity separators that remove the portion of oil which quickly and easily separates from water. Figure IX-2 presents a diagram of a skim pile.

During the period of no flow, oil will rise to the quiescent areas below the underside of inclined baffle plates where it coalesces. Due to the difference in specific gravity, oil floats upward through oil risers from baffle to baffle. The oil is collected at the surface and removed by a submerged pump. The pump operates intermittently and removes the separated liquid to a skimming vessel for further treatment.

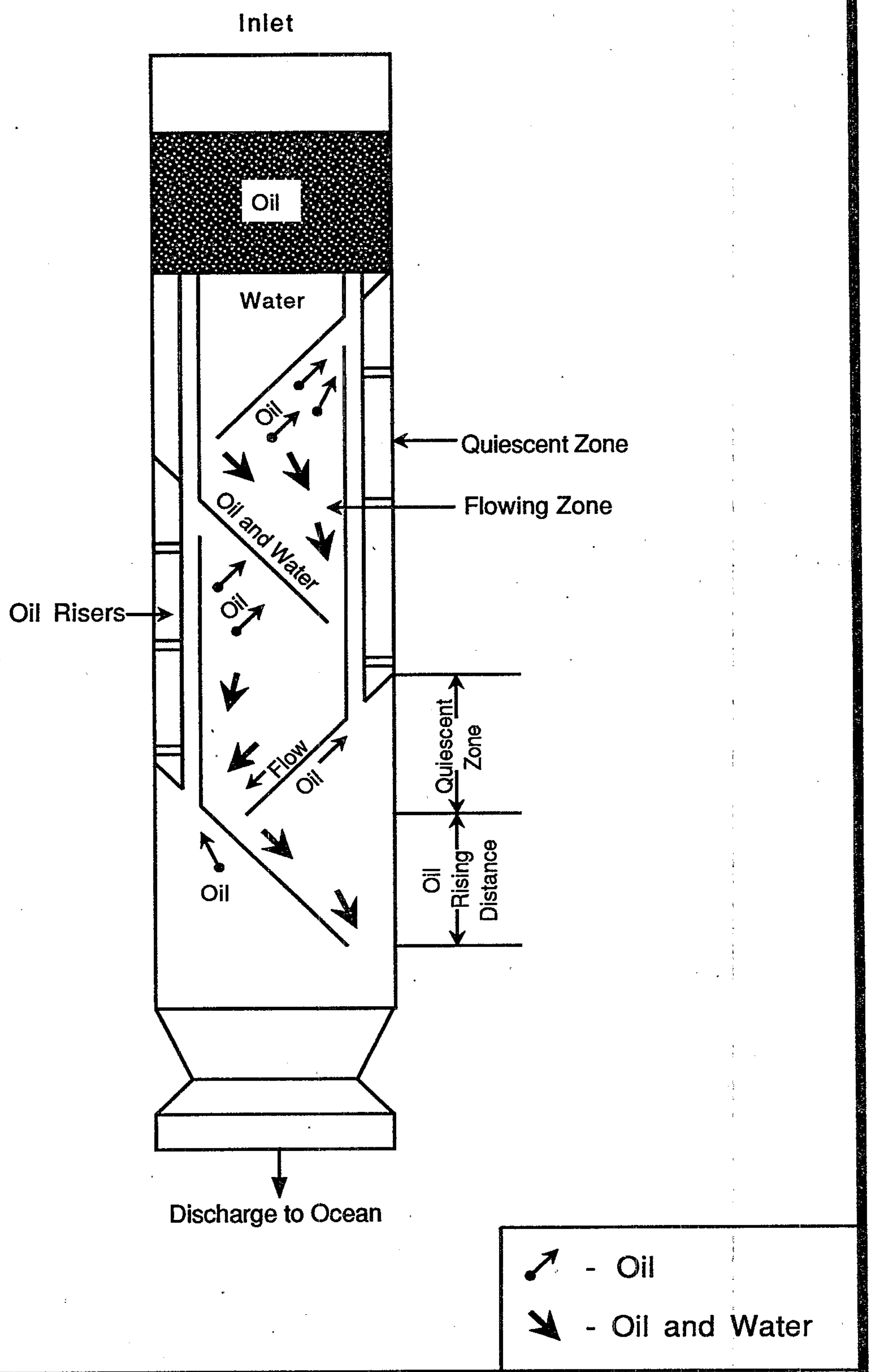

Figure IX-2
Typical Skim Pile

5.1.8 Reinjection

Subsurface disposal may be used in BPT treatment. Reinjection is generally used for waterflooding (or in water quality limited areas) which, as a result, meets BPT limitations. Reinjection is discussed in detail later in Section 5.2.2.

5.2 Additional Technologies Evaluated for BAT and NSPS Control

Several produced water treatment technologies were considered as add-on technologies to the existing BPT technologies to achieve BAT and NSPS limitations. In particular, EPA evaluated the following technologies for BAT and NSPS level of control: gas flotation, subsurface reinjection, granular filtration, crossflow membrane filtration, and activated carbon adsorption. The following sections describe these technologies in detail.

5.2.1 Improved Performance of Gas Flotation Technology

EPA evaluated the costs and feasibility of improved performance of gas flotation treatment systems to determine whether more stringent effluent limitations based on this technology would be appropriate. This technology would consist of improved operation and maintenance of gas flotation treatment systems, more operator attention to treatment systems operations, chemical pretreatment to enhance system effectiveness, and possible resizing of certain treatment system components for increased treatment efficiency.

The performance of a gas flotation process is highly dependent on the bubble-particle interaction. The mechanisms of this interaction include: (1) precipitation of the bubbles on the particle surface, (2) collision between a bubble and a particle, (3) agglomeration of individual particles or a floc structure as the bubbles rise, and (4) absorption of the bubbles into a floc structure as it forms. These mechanisms indicate that surface chemistry aspects of flotation play a critical role in improving the performance of gas flotation. In fact, chemicals have been an integral part of the flotation process for some time.[9]

Three basic types of chemicals, which are previously discussed in Section 5.1.6, are generally utilized to improve the efficiency of the gas flotation units used for treatment of offshore produced water; these chemicals are surface active agents, coagulating agents, and polyelectrolytes.

Researchers have demonstrated that the addition of chemicals to the water stream is an effective means of increasing the efficiencies of gas flotation treatment systems.[11,17,18,19] Pearson, 1976, reported that the use of coagulants can drastically increase the oil removal efficiency of dissolved-gas flotation units.[12] The addition of alum plus polyelectrolyte to a flotation cell treating refinery wastewater increased the unit efficiency from 40 percent to 90 percent. Luthy, et al., 1978, also demonstrated the effectiveness of polyelectrolytes for improving the effluent quality of dissolved-gas flotation units treating refinery wastewater.[20] The addition of chemicals to gas flotation units treating produced water may result in somewhat different removal efficiencies due to the formation specific chemical characteristics and salinity of the produced water. Also, removal efficiencies may be different for induced gas flotation (most common type of gas flotation in the offshore industry).

Factors related to engineering or mechanical design aspects of the gas flotation systems which could also affect process performance include:

(1) Type of gas available or used
(2) Pressure supplied and temperature (DGF)
(3) Type and condition of eductor (IGF)
(4) Rotor speed and submergence (IGF)
(5) Percent recycle (DGF) or rate of recycle (IGF)
(6) Influent characteristics, concentration, and fluctuations
(7) Hydraulic and mass loadings
(8) Chemical conditioning
(9) Type and operation of skimmer.

A review of the design parameters for 32 gas flotation units surveyed by EPA in 1975 revealed that these units were designed for maximum expected hydraulic loadings. However, none were designed to handle mass overload conditions which may occur during start-up, process malfunctions, or poor operating practices. The survey also indicated that those systems that were properly designed, maintained, and operated had excellent performance. Produced water effluent oil concentrations from these systems averaged less than 25 mg/l.[19]

The limitations representing the best practicable control technology (BPT) for treatment of offshore produced water (determined by EPA based on the analysis of 138 systems) are based on the following technologies: (1) equalization or surge tanks to provide a steady influent to the treatment system and to prevent overloading of the system, (2) solids removal (desanders) to remove undesirable solids that could clog-up the treatment units and damage the equipment, (3) chemical addition (feed pumps) to enhance the system's performance, and gas flotation for oil removal. *A great majority of the existing* units either have this capability or could be modified. Most modifications are simple and could utilize the existing tankage and equipment with minimal costs. For example, according to a case study conducted by Rochford, 1986, an inadequately designed induced gas flotation system operating in North Sea was successfully modified to operate as a dissolved gas flotation with minimal capital cost.[21] The IGF unit was not designed to treat produced water with very small oil droplets (5 to 40 microns), thus achieving only 30 percent removal efficiency. The modified system simplified the equipment required for conventional DGF systems by utilizing the existing tanks and the dissolved gas already present in the produced water. The new system efficiency ranged between 70 to 80 percent.

In general, gas flotation systems may have removal efficiencies of 90 to 95 percent.[13] With proper operation, chemical addition, and low suspended solids concentration, a mechanical-type IGF system can consistently achieve oil removal efficiencies greater than 90 percent, even when operating at capacities beyond the design flowrates. Some older and larger size hydraulic-type IGF systems using one eductor per cell have not demonstrated the capability to consistently exceed 90 percent oil removal efficiency at one minute residence time per cell. However, the newer designs which have employed multiple eductors in each cell, more cells for the same volume, a means of ensuring smaller bubbles, and superior baffle design give comparable performance to mechanical-type units. As a general design rule, gas flotation units used for treating oily water should have a large drain piping system, at least 4-inches in diameter, to prevent foam plugging. Also, adequate surge capacity is necessary upstream of IGF units to protect the system from oil "slugs," eliminate flowrate surges, and to remove suspended solids.[11]

5.2.2 Reinjection

Disposal of produced water by reinjection into a subsurface geological formation can serve the following purposes:

- Provide zero discharge of wastewater pollutants to surface waters.
- Increase hydrocarbon recovery by flooding or pressurizing the oil bearing strata.
- Stabilize (support) geologic formations which settle during oil and gas extraction (a significant problem for older, i.e onshore, more depleted reserves).

Onshore produced water reinjection is a well-established practice for disposal of produced water.

As part of the rulemaking process, and in response to industry concerns about the feasibility of reinjection due to the receiving formation characteristics, EPA evaluated the technical feasibility of implementing this technology at both existing and new offshore platforms.[22] 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, some locations may experience problems in being able to reinject due to site-specific formation characteristics or proximity to seismically active areas.

The following sections present information on the reinjection technology as a means to control produced water discharges.

5.2.2.1 *Industrial Practices*

Most of the produced water generated offshore California is presently reinjected to enable recovery of the heavy crude oil that is typically produced in that part of the country. However, in the Gulf of Mexico, most produced water generated offshore is treated to the BPT limitations and discharged to the surface waters. Onshore reinjection experiences in Texas and Louisiana have shown that the characteristics of the regional geology make it possible to reinject produced water onshore. EPA also believes that it is generally possible to reinject produced water in areas that EPA recognizes as offshore.

The only EPA-defined offshore facility in Alaska, which is located on a gravel island in the Beaufort Sea, reinjects all of its produced water. In other coastal areas of Alaska, this technical issue has not yet been specifically evaluated. At an onshore facility at Trading Bay, a technical evaluation of the formation's geological suitability for reinjection indicated that the formation was highly faulted and that compartmentalization is likely, thus reducing the capacity of the formation for use in receiving injected fluids to approximately two years. Other evaluations on the feasibility of reinjecting produced water have been limited to economic issues.[23]

5.2.2.2 *Well Selection and Availability*

Many of the requirements in the planning, design, and operation of the produced water reinjection system are the same whether the location is onshore or offshore. These include important design considerations such as selection of a receiving formation, preparation of an injection well, and choice of equipment and materials. Significant operational parameters include scaling, corrosion, incompatibility with the receiving stratum, and bacterial fouling.

Selection of the receiving formation should be based on geologic as well as hydrologic factors. These factors determine the injection capacity of the formation and the chemical compatibility of the injected produced water with the water within the formation. The most important regional geologic characteristics of a disposal formation are areal extent and thickness, continuity, and lithological character. This information can be obtained or estimated from core analysis, examination of bit cuttings, drill stem test data, well logs, driller's logs, and injection tests.

The desirable characteristics for a produced water reinjection formation are: an injection zone with adequate permeability, porosity, and thickness; an areal extent sufficient to provide liquid-storage at safe injection pressures; and an injection zone that is confined by an overlying consolidated layer which is essentially impermeable to water. There are two common types of intraformation openings: (1) intergranular and (2) solution vugs and fracture channels. Formations with intergranular openings are usually made up of sandstone, limestone, and dolomite formations and often have vugulur or cavity-type porosity. Limestone, dolomite, and shale formations may be naturally fractured. Formations with fracture channels are often preferable for produced water disposal because fracture channels are relatively large in comparison to intergranular openings. These larger channels may allow for fluids with high concentrations of suspended solids to be injected into the receiving formation under minimum pumping pressure and minimal pretreatment.

A formation with a large areal extent is desirable for disposal purposes because the fluids within the disposal formation must be displaced to make room for the incoming fluids. An estimate of the areal extent of a formation is best made through a subsurface geological study of the area. If it is possible to inject water into the aquifer of some oil- or gas-producing formation, the size of the disposal formation is not critically important. Under these circumstances, the reinjected water would displace water from the aquifer into the producing reservoir from which fluids are being produced. Thus, the pressure in the aquifer would only increase in proportion to the amount that water reinjection exceeds fluid withdrawals. Pressure-depleted aquifers of older producing reservoirs are highly desirable as disposal formations.

Formations capped or sandwiched by impervious strata generally will assure that fluids pumped into the formation will remain in place and not migrate to another location.[1] Abandoned producing formations are ideal for disposal because the original fluids were trapped in the formation. Fluids reinjected into those formations also will be trapped and will not migrate into other areas.

5.2.2.2.1 Possible Concerns

Faulting in an area should be evaluated critically before locating a disposal well, particularly if the disposal formation is other than an active or abandoned oil or gas producing formation.[22] Depending upon local stratigraphy and the type and amount of fault displacement, one of three possible conditions can occur. Displacement along the fault may either: (1) limit the area available for disposal; (2) place a different permeable formation opposite the disposal formation which could allow fluids to migrate to unintended locations; or (3) the fault itself may act as a conduit, allowing injected fluids to flow along the fault plane either back to the surface or to permeable formations at a shallower depth than the disposal formation. Either the second or third possibility has the potential to create a pollution problem by contaminating underground sources of drinking water.

Another concern associated with faulting is that fluids entering the fault or fault zone may cause a reduction in friction along the fault plane, thus allowing additional, and perhaps unwanted, displacement to occur.[22] Such movement can create seismic activity in the area. The city of Denver, Colorado placed a disposal well near the Rocky Mountain Arsenal and pumped city waste water down the well. The well bottom was in the vicinity of a fault. Subsequent analysis showed a direct correlation between the number of microseisms in the Denver area and well pumping times and rates. Increased pumping caused a corresponding increase in the number of microseisms.

5.2.2.2.2 Well Design

Whether the objective is enhanced ("secondary") recovery or disposal, a primary requirement for the proper design of a reinjection well is that the produced water be delivered to the receiving formation without leaking or contaminating fresh water or other mineral bearing formations. The reinjection well may be installed by either drilling a new hole or by converting an existing well. The types of existing wells which may be converted include: marginal oil producing wells, plugged and abandoned wells, and wells that were never completed (dry holes). If an existing well is not available for conversion, a new well must be drilled. Moreover, for reinjection from offshore platforms, adequate equipment and storage space must be provided at the facilities.

5.2.2.2.3 Regional Geological Considerations

California

There is little question about the technical feasibility of reinjecting produced water at the existing facilities offshore California because the current practice of this technology is common. In the offshore subcategory for California, all of the produced water are reinjected for the sole purpose of enhanced recovery by waterflooding. Reinjection of produced water is not practiced in areas where there is potential for seismic activity. The offshore geological conditions and engineering requirements for the reinjection of brines from new sources in areas expected to be open for oil and gas development and production, i.e., free of seismic activity, are expected to be essentially the same as for existing sources. Consistent with the past and present industry practices, suitable disposal formations with adequate permeability, porosity, thickness, and areal extent are expected to be available. Similarly, constructability and trouble-free operation of reinjection wells, availability of offshore pretreatment technologies, and the transport and onshore disposal of solids and sludges from new sources pose no additional technical problems beyond those currently encountered due to the reinjection of brines from existing sources.

Gulf of Mexico

In the Gulf of Mexico, reinjection of brines from existing offshore sources is not practiced to any appreciable extent. The current practice is to treat the brines to the BPT effluent limitations and discharge overboard. Waterflood projects are not common in the Gulf of Mexico; it is estimated that less than ten facilities in the Gulf of Mexico reinject produced water for pressure maintenance.[24] The primary reason that waterflooding is not common offshore is because, unlike California, extraction of the formation fluids from the reservoirs in the Gulf of Mexico does not require the additional water drive provided by waterflooding. Secondly, economics prevent secondary recovery operations in the Gulf of Mexico. The additional oil recovered due to waterflood is not worth the cost of the reinjection operation. An effective waterflood program requires several wells, since waterflooding operations often push the oil zone up and horizontally direct the movement of the zone to the production well. "Textbook" waterflooding operations utilize a five spot pattern to properly manage the flow of the oil zone. A five spot pattern consists of four injection wells surrounding the production well, typically in a square pattern. Through the control of injection water from the four wells, the oil zone can be directed to the area where the production well is located. This type of waterflooding program is very expensive in offshore operations since several directionally drilled wells are required.[25]

Reinjection of brines from existing and new sources in the Gulf of Mexico also depends on the availability of an adequate number of suitable disposal formations. In the early stages of production, there will be little need for reinjection fluids to enhance recovery and, therefore, the produced water would be reinjected only for disposal purposes. The onshore reinjection experience in Texas and Louisiana has shown that reinjection of produced water is possible where there are suitable disposable formations available. Consistent with the onshore experience, there may be instances where a suitable disposal formation may not be available.

5.2.2.2.4 Technical Exceptions

Reinjection into producing formations is not extensively practiced offshore along the Gulf Coast because of potential problems that waterflooding can cause by adversely changing the field pressure.[22] These pressure changes can cause a production loss from either coning at the wellbore or, if there is directional permeability within the reservoir, the rapid return of injected water back to the wellbore. Increased pressure can also cause movement of the formation fluid containing the oil and gas away from the wellbore. These movements may result in reduced production. Because each production area has its own unique set of conditions, each site must be individually evaluated for potential problems that may arise from reinjection into a producing formation.

Other sources indicate that although it is theoretically possible to reinject produced water into subsurface formations, the consequences of injecting large quantities of produced water are impossible to determine, and the potential impacts are significant. Approximately 1 billion barrels of produced water are generated annually in the offshore subcategory. Since many formations in the Gulf are small, tightly packed, and have relatively low permeability and porosity, one resulting problem could be fracturing and eventual flow of the produced water back to the surface, through the ocean floor, and/or flow to a fresh water aquifer. Another consideration is that because of the formation characteristics in the Gulf, the produced water will require very intensive pretreatment to remove the solids.

5.2.2.3 Pretreatment of Produced Water Prior to Reinjection

Pretreatment of produced water may be necessary to prevent scaling, corrosion, precipitation, and fouling from solids and bacterial slimes. Corrosion and scale deposits lead to decreased equipment performance and to plugging in the underground formation. One method to overcome this problem is to increase reinjection pressures. However, excessive injection pressure may fracture the receiving formation causing the escape of produced water into freshwater or other mineral bearing formations.

Also, additional energy (fuel) is necessary to obtain the higher discharge pressures and consequently results in increased air emissions.

Offshore treatment systems are classified as closed systems which operate in the absence of air. This alleviates the problems arising from oxygen induced corrosion, scaling, and chemical precipitation. In a closed system, a blanket of natural gas is maintained over the produced water in pipelines and tanks.

Pretreatment for injection includes gravity separation, gas flotation, and/or filtration. This level of pretreatment is generally more elaborate than the current pretreatment practices in the Gulf of Mexico where produced water is treated and discharged to the surface waters. Space requirements or the reliability of the pretreatment technology pose no additional problems beyond those encountered offshore of California where the same level of pretreatment is currently practiced prior to reinjection. However, the facilities in California were originally designed to include the additional equipment required for pretreatment and reinjection.

5.2.3 Granular Filtration

Granular media filtration involves the passage of water through a bed of filter media to remove 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. There are a number of variations in filter design systems. These include: (1) the direction of flow: downflow, upflow, or biflow; (2) types of filter beds: single, dual, or multi-media; (3) the driving force: gravity or pressure; and (4) the method of flow rate control: constant-rate or variable-declining-rate.[26] Figure IX-3 shows the schematic of a multi-media granular filter.

Filtration is widely used for produced water treatment at onshore facilities throughout the United States, as well as at some offshore facilities located in California state waters. The filters are used as a polishing step for the removal of suspended solids following the oil separation processes. High levels of treatment which include filtration are generally utilized to improve the injection characteristics of produced water.[26]

The three-facility study evaluated granular filtration systems designed to pretreat produced water following oil separation and prior to reinjection. These particular operations inject produced water either because of a zero discharge permit requirement or for enhanced oil recovery. The three facilities

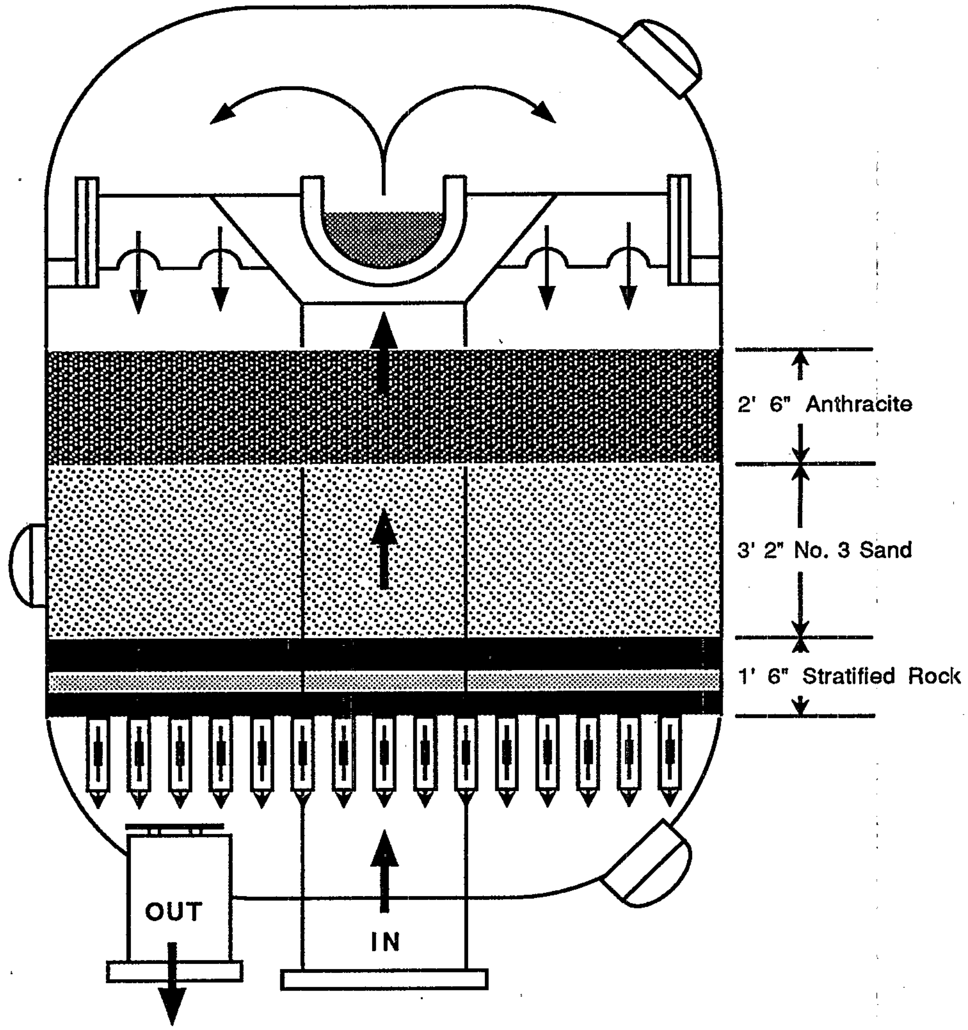

Figure IX-3
Multi-Media Granular Filter

evaluated were: Conoco's Maljamar Oil Field near Hobbs, New Mexico; Shell Western E&P, Inc. - Beta Complex off Long Beach, California; and the Long Beach Unit - Island Grissom which is owned by the City of Long Beach, California, and operated by THUMS Long Beach Company.

At the THUMS facility, approximately 90,000 barrels per day (bbl/day) of produced water are treated. To provide sufficient water for reinjection purposes, approximately 28,000 bbl/day of make-up water is added to produced water prior to reinjection. Produced water is first treated to remove oil in a series of free water knockouts (FWKOs) and clarifiers. Water from the clarifiers is passed through a series of dispersed gas flotation units and ultra-high-rate multi-media granular filters. There are three filters operating in parallel and a fourth is used as a spare during the backwash cycles. The filters operate in a downflow configuration and the filtering media consists of (from top to bottom): a layer of crushed anthracite (effective size 6-4 mm), a layer of Number 3 sand, and a layer of stratified rock. Oil removed in the treatment system is further treated in the API skim tank. Prior to filtration, coagulant and demulsifier chemicals are added to the water.

At the New Mexico facility, approximately 21,000 bbl/day of produced water are treated. To provide sufficient water for reinjection purposes, approximately 4,000 bbl/day of fresh water is added to the produced water before filtration, requiring the filters to handle approximately 25,000 bbl/day of water. There are three upflow sand filters operating in parallel. Prior to filtration, corrosion inhibitor, coagulant, and flocculent aid chemicals are added to the water to enhance separation.

At Shell Western-Beta Complex, approximately 10,000 bbl/day of produced water are treated. To provide sufficient water for reinjection purposes, approximately 28,000 bbl/day of de-gasified make-up water is added to the produced water. Produced water is fed to a skim tank for oil-water separation. Water flows from the skim tank by gravity to a flotation unit. Prior to the flotation unit, a chemical coagulant is injected into the produced water stream. Following flotation, water is pumped to two multi-media filters operating in parallel, one additional filter is on stand-by mode and used during backwash cycles. The filters are the same as those described for the THUMS facility, however, there is no chemical addition at the filtration unit to aid in the separation process. Filtered water is gravity fed to an injection surge tank where it is mixed with make-up water. Water from this tank is partially pumped through cartridge filters and reinjected, and partially pumped to the backwash water storage tank.

EPA statistically analyzed the data from these facilities to determine effluent levels achievable from add-on granular media filtration technology. Table IX-16 presents the performance of granular

TABLE IX-16

GRANULAR MEDIA FILTRATION PERFORMANCE[27]

	TSS (mg/l)*	O&G (mg/l)**
Thums Long Beach (With Chemical Addition)		
Filter Influent	43.27	20.75
Filter Effluent	25.65	11.22
% Removal	40.7%	46%
Conoco, Hobbs (With Chemical Addition)		
Filter Influent	102.84	34.54
Filter Effluent	48.77	10.90
% Removal	53%	68%

*TSS concentrations represent flow weighted averages of paired samples for each day of sampling.
**Composite sample concentrations estimated by the arithmetic average of sample concentrations within a day.

media filtration for oil and grease (O&G) and TSS, based on calculated daily composites. Granular filtration has demonstrated good removals of TSS and oil and grease at the two facilities using chemical coagulants and flocculatants to enhance separation, thus improving filtration performance.

5.2.4 Crossflow Membrane Filtration

Crossflow membrane filtration is an ultrafiltration process. The process operates at low pressures, less than 100 pounds per square inch (psi). The membrane pore sizes range from 0.03 to 0.8 micrometers. Crossflow filtration minimizes the accumulation of particulates on the surface of the membrane by flowing the feed stream over the surface of the membrane to sweep away part of the accumulated layer on the membrane. Figure IX-4 presents the flow dynamics of a crossflow filter. Crossflow filtration requires recirculation of the process stream that may be several orders of magnitude greater than the rate of filtration. The advantage of crossflow filtration is that the membrane's life and periods between cleaning cycles are extended through constant membrane scouring by the particulates in the produced water stream.[28] In addition to the high velocities of produced water across the membrane

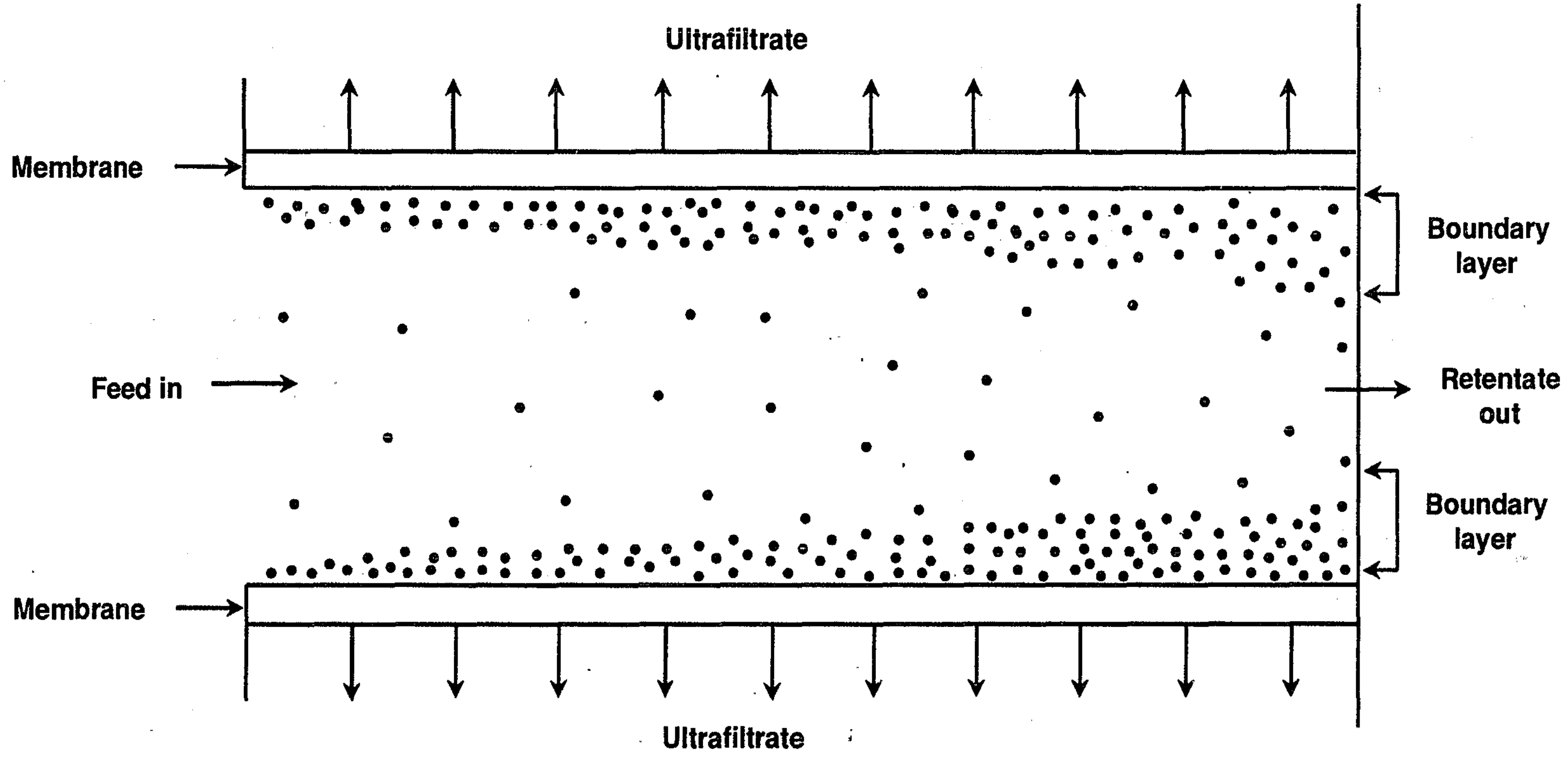

Figure IX-4
Flow Dynamics of a Crossflow Filter

surface to prevent membrane fouling, some systems utilize a backflow of permeate (i.e., filter effluent) through the membrane to dislodge any oil or solid particles embedded within the pores of the membrane.

Several types of crossflow membrane filters have been pilot or field tested for the treatment of produced water. The two common types of membrane materials are an inorganic ceramic material and an organic polymeric material. Membrane module designs include hollow fiber, spiral wound, and tubular. Many systems require either pre-filtration or chemical treatment to prevent rapid membrane fouling and flux degradation. For flux restoration, some systems utilize on-line membrane cleaning, such as backpulsing, while others require system shutdown and physical cleaning of the membrane.

One type of crossflow membrane filtration system is currently being operated on two different platforms located in the Gulf of Mexico. One is a 150 barrel per day pilot scale unit and the other is a 5,000 barrel per day full scale unit processing a partial stream (slip stream) of the produced water for waterflood injection purposes.[29] The ceramic membranes used in these filtration modules are made of porous alumina. Each module contains up to 36 ceramic elements. The bulk of the ceramic element is a ceramic monolithic support containing 12 micrometer pores. Each element contains 19 channels arranged in a honeycomb configuration, which are stratified with alumina ceramic layers that are bonded to the monolithic support. These alumina layers have a pore size of 0.8 microns. Figure IX-5 presents a cross section of a ceramic element. The produced water flows axially through each channel and radially permeates through the membrane layer and supporting structure.

The produced water stream is chemically pretreated with ferric chloride. Through a hydrolysis reaction between the produced water and ferric chloride, a ferric hydroxide floc is formed. The ferric hydroxide floc develops a precoat layer on the surface of the membrane and serves as a "dynamic membrane." This "dynamic membrane" is unique to this system and allows water to permeate through the ceramic membrane while reducing the rate of accumulation of oil and oil wet solids on the membrane surface. The backpulse cycle serves to constantly replace the "dynamic membrane" with a fresh ferric hydroxide floc precoat. However, the "dynamic membrane" does not completely prevent the membrane from fouling. When backpulsing does not restore the permeate flux rates, shutdown of the system is necessary for chemical cleaning.[30]

In 1991, EPA conducted a week long sampling episode of the full scale unit described in the preceding paragraphs. Data obtained from this sampling effort indicate that the total oil and grease of the effluent can be as low as 3.5 mg/l with an influent oil and grease concentration of 22 mg/l. The

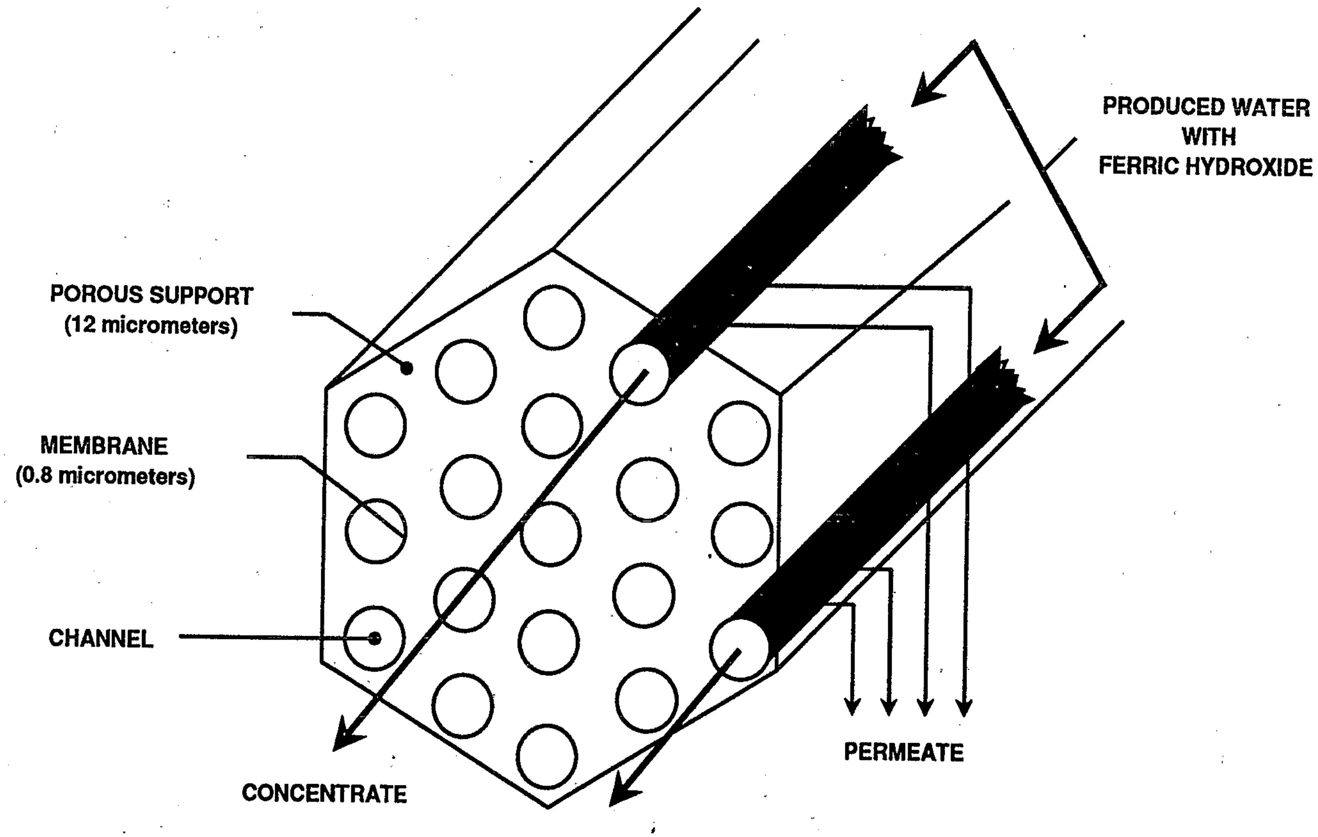

Figure IX-5
Module Assembly of Several Multichannel Elements of a Crossflow Membrane Filter[30]

sampling program also analyzed the filtration process for removal efficiencies and potential concentration of TSS, organic compounds, metals, and radionuclides. Table IX-17 presents data obtained from the sampling program.

Despite the potential of high pollutant removal efficiencies, widespread use of crossflow membrane filtration for the treatment of produced water has been hampered by operational problems, due to membrane fouling, experienced by several of the pilot and full scale units, including the unit studied in the 1991 EPA sampling program. The unit evaluated was being operated at 20 percent of the design capacity due to a barium sulfate scale build-up on the membrane surface.

The filtration unit was also bypassed several times during the sampling program due to upsets in the produced water treatment system. The unit was bypassed as a preventative measure to avoid sending water with a relatively high oil and solids content to the filter. The membrane pores can be easily plugged during high loadings of oil and solids. If the membrane pores become oil wet or plugged with solids, significant flux reduction results and shutdown of the filter is necessary for chemical cleaning. The operator was also experiencing problems with the waste streams generated from the filtration process. The major waste streams generated by the unit include: the only float skimmed at the feed tank surface, the solids concentrate blowdown stream, and the spent acid and caustic used for filter cleaning. The wastes are currently recycled into the produced water treatment system or neutralized and discharged overboard. The wastes being recycled into the produced water treatment system are creating upsets in the chemical equilibrium of the system. The operator indicated that a larger filtration unit would generate greater volumes of waste which would be difficult to recycle into the produced water treatment system without causing significant upsets and be costly to dispose of onshore.[32]

Also in response to the 1991 proposal, EPA received bench, pilot, and full scale analytical and operating data from several vendors of crossflow membrane filters. The commenters submitted data and information on several field tests processing produced water at locations in the Gulf of Mexico, Kansas, Alaska, California, Canada, and the North Sea. All of the analytical data indicated high removal efficiencies for oil and grease and total suspended solids. This information is presented in a literature study titled "Crossflow Membrane Separation System Study."[30]

The only other full scale crossflow membrane filtration unit that EPA is aware of is a ceramic membrane operating in the Valhalla field located in northeastern Alberta, Canada.[33] The unit has a rated design capacity of 6,000 barrels per day and is processing a combined produced water and ground water

TABLE IX-17

MEMBRANE FILTRATION PERFORMANCE DATA FROM THE MEMBRANE FILTRATION STUDY[31]

Pollutant Parameter	Influent (μg/l)			Effluent (μg/l)		
	MIN*	MAX*	MED*	MIN*	MAX*	MED*
Oil & Grease						
Freon	16.33	42.67	19.67	3	7.67	4.67
Hexane	8.0	21.67	11.0	3.0	6.33	3.33
Total Petroleum Hydrocarbon	16.33	42.67	19.67	3.0	7.67	4.67
TSS	67.0	86.0	82.0	86.0	97	97
Priority and Non-conventional Organic Pollutants:						
Benzene	738.38	1,050.32	925.35	441.5	958.9	860.0
Benzoic acid	51	84.83	67.82	50.0	50.4	50.0
Biphenyl	10	557.41	10	10	10	10
Chlorobentene	10	16.5	11.78	10	15	10
Ethylbenzene	62.6	114.3	90.1	10	77.2	61.8
Hexanoic Acid	10	14.4	10	10	47.2	10
Methylene Chloride	10	148.3	83.2	10	138.7	10
Naphabene	10	29.6	17.8	10	21.5	13.1
o,p-Xylene	34.15	83.4	53.7	31.0	47.3	35.4
Phenol	10	53.4	10	10	66.1	10
Toluene	438.4	650.5	556.7	445.9	607.1	517.5
2-Butanone	180.4	1,206.0	282.0	182.1	2,610.2	305.8
2-Propanone	50	1,901.1	1,004.3	50	2,686.1	1,215.2
Priority and Non-conventional Metal Pollutants:						
Aluminum	875	2,270	1,660	343	1,351	1,100
Antimony	3	617	30	30	4,200	264
Arsenic	165	211	187	127	256	160
Barium	92,150	135,220	130,000	90,250	142,000	128,000
Boron	6,950	8,050	7,620	6,790	7,830	7,570
Copper	30	31	30	30	30	30
Iron	24,300	28,800	27,500	26,100	28,450	26,900
Lead	150	530	150	150	314	212
Magnesium (mg/l)	2,280	2,495	2,450	2,280	2,495	2,460
Manganese	1,440	1,965	1,960	1,910	2,325	2,265
Strontium (mg/l)	181	224	218	202	226	216.5
Titanium	9	12	9	9	17	9
Yttrium	9	14	9	9	17	9
Zinc	24	38	25	24	45	28
Radionuclides:						
Gross Beta (pCi/l)	296.0	442.5	328.0	296.0	390.5	304
Radium 226 (pCi/l)	381.0	643.0	484.0	521.0	616	583.0
Radium 228 (pCi/l)	511.8	863.6	604.3	130.4	868.3	579.7

*Pollutant Concentration "Minimum Level" Values were Substituted for Non-detect Samples
NR=Not Reported

stream for pretreatment prior to reinjection. The system was installed the fourth quarter of 1990 and until 1992 had not been in continuous operation. The system was frequently shut down due to membrane fouling problems. However, recent design changes have improved its ability to operate continuously without membrane fouling.

5.2.5 Activated Carbon Adsorption

Activated carbon is a material which selectively removes organic contaminants from wastewater by adsorption. Activated carbon can be used both as an in-plant process for the recovery of organics and as an end-of-pipe treatment for the removal of dilute concentrations of organics from wastewater prior to discharge or recycle. Key design parameters for an activated carbon unit include the quantity and quality of wastewater to be treated, the required effluent quality, type and quantity of activated carbon, the empty bed contact time, and the breakthrough capacity before regeneration is necessary.

Generally, activated carbon systems are preceded by treatment systems such as chemical treatment or filtration to remove the suspended solids and any other materials which might be present in the wastewater and which interfere with the adsorption phenomenon. Presently, activated carbon is not generally used in the treatment of produced water from oil and gas wells.

EPA determined that carbon adsorption is not technologically available to implement as a basis for BAT or NSPS limitations for the treatment of produced water from offshore oil and gas production. This is because of the lack of treatability information related to the effects of the brine-like nature of produced water on the adsorption process, either from literature or from pilot or full-scale studies.

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SECTION X

MISCELLANEOUS WASTE—CHARACTERIZATION, CONTROL AND TREATMENT TECHNOLOGIES

1.0 INTRODUCTION

This section describes the sources, volumes, and characteristics of miscellaneous waste streams from offshore oil and gas exploration, development, and production activities. The miscellaneous waste streams considered for regulation are:

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

This section also includes a brief description of the minor waste streams associated with offshore oil and gas drilling and production and a description of the treatment technologies currently available to reduce the quantities of pollutants associated with these wastes.

2.0 PRODUCED SAND

Produced sand consists of the slurried particles used in hydraulic fracturing and the accumulated formation sands and other particles (including scale) generated during production. This waste stream also includes sludges generated by any chemical polymer used in the filtration portion (or other portions) of the produced water treatment system. The following sections describe the sources, volumes, characteristics, and treatment methods for produced sand.

2.1 PRODUCED SAND SOURCES

Produced sand is generated during oil and gas production by the movement of sand particles in producing reservoirs into the wellbore, as well as by silica material spalling off the face of the producing formation. The generation of produced sand usually occurs in reservoirs comprised of young, unconsolidated sand formations.[1] Produced sand is considered a solid and consists primarily of sand and clay with varying amounts of mineral scale (epsom salts, magnesite, gypsum, calcite, barite, and celestite) and corrosion products (ferrous carbonate and ferrous sulfide).[2]

Produced sand is carried from the reservoir to the surface by the fluids produced from the well. The well fluids stream consists of hydrocarbons (oil or gas), water, and sand. At the surface, the production fluids are processed to segregate the specific components. The produced sand drops out of the well fluids stream during the separation process due to the force of gravity as the velocity of the stream is decreased during passage through the treatment vessels. The sand accumulates at low points in the equipment and is removed periodically through sand drains, manually during equipment shut-downs for cleaning, or by periodic blowdowns as a wet sludge containing both water and oil.[3] One source indicates that desanders or desilters (hydrocyclones) are used to remove sand if the volume produced is high.[2] However, the Offshore Operators Committee (OOC) indicates that sand removal is primarily by tank cleanouts and that desanders are seldom used. Equipment is typically cleaned on a three to five year cycle. At some locations, sand is collected on a yearly basis because large volumes of sand are being generated due to failure of downhole sand control measures.[4] Sand removal by blowdown through valves installed on tank and equipment accounts for approximately 10 percent of all sand generated at offshore facilities.[4]

2.2 PRODUCED SAND VOLUMES

The generation rate of produced sand will vary between wells and is a function of the: amount of total fluid produced, location of the well, type of formation, production rate and completion methods.[2,3] Oil producing reservoirs will typically generate more produced sand than gas producing reservoirs. This is because oil is more viscous than gas and the oil will carry the sand more easily than gas. Another reason is because gas producing wells have sensors that detect sand flowing with the gas stream to prevent erosion on the production equipment due to sand flowing with the gas at high velocities.[5]

In 1989, a survey of operators in the Gulf of Mexico was conducted by the OOC that compiled data on produced sand discharges from 330 sites operated by thirteen different companies.[4] Table X-1 presents a summary of the data collected in the survey. The information collected for each site includes:

TABLE X-1

SUMMARY OF RESULTS OF OOC PRODUCED SAND SURVEY[4]

Total Number of Sites Included in the Survey	330
Number of Sites Collecting Produced Sand for the Survey Year	143
Number of Sites Discharging Only to Sea	21
Number of Sites Hauling Only to Shore	115
Number of Sites Hauling to Shore and Discharging to Sea	7
Number of Sites reporting No Produced Sand Generation	63
Maximum Discharge of Produced Sand Per Site	12,565 bbl
Maximum Haul of Produced Sand Per Site	1,508 bbl
Average Discharge of Produced Sand	1,136 bbl
Average Haul of Produced Sand	110 bbl

- The amount of produced sand discharged (barrels)
- The amount of produced sand hauled to shore (barrels)
- The amount of produced water generated (barrels).

Since produced sand is not collected from process equipment every year, the survey only represents a snapshot of produced sand collection for a given year. Forty-three percent (43%) of the facilities surveyed indicated no discharging or hauling of produced sand in 1989. This does not indicate that these facilities did not generate any produced sand that year. It indicates that either these facilities did not generate any produced sand or no produced sand was collected from the process equipment for that year. Several years of data in this format would be necessary to draw any conclusions about yearly produced sand generation rates.

The OOC survey indicates that less than half of the sites surveyed discharged produced sand in 1989. Of the sites discharging produced sand, 15 percent discharged to the surface waters, 80 percent hauled to shore and 5 percent hauled to shore and discharged to the surface waters. The total sand production from the 143 sites discharging sand was 41,627 barrels, which equals approximately 291 barrels discharged per site. Of this volume, 28,403 barrels (68%) were discharged to the surface waters and 13,229 barrels (32%) were hauled to shore.

Several facilities in the survey reported over one-thousand barrels of produced sand discharged to the surface waters and one facility accounted for forty-four percent (12,565 barrels) of all produced sand reported to be discharged to the receiving waters (28,403 barrels). EPA considers these volumes extremely high when compared with the other reported collection volumes in the survey. A follow-up telephone conversation with one operator indicated that one of the facilities reporting over 4,000 barrels of produced sand discharged in 1989 produces about 100 barrels of sand a year (at this annual generation rate, it would take 40 years to generate this volume). The operator indicated that another facility generates sand continuously at a rate of approximately 5 barrels per day.[6] However, no specific reasons were provided that explained the large volumes of sand.

2.3 PRODUCED SAND CHARACTERIZATION

Produced sand is generally contaminated with crude oil from oil production or condensate from gas production. The primary contaminant associated with produced sand is oil.[7] The oil content of unwashed produced sand can range from a trace (expected in sand from blowdown) to as much as 15 percent by volume.[8]

In 1991, Shell Offshore, Inc. conducted a produced sand washing study. The study evaluated produced sand that was generated at a facility located in the Mississippi Canyon Area (Gulf of Mexico OCS) and washed and discharged at a platform located in West Delta Area. The oil and grease content of unwashed produced sand ranged from 0.5 to 6.1 percent by weight or 6 to 14 percent by volume.[9] This material had already undergone bulk solids separation in conjunction with tank cleaning operations prior to being analyzed for oil and grease.[10] Thus, some of the free oil could have been removed during this process. Table X-2 presents the oil and grease data of the unwashed and washed produced sand.

Elevated levels of ^{226}Ra and ^{228}Ra have been detected in some produced sand samples. The 1989 OOC produced sand survey and the 1991 sand washing study contained data on the level of radioactivity in produced sand.

Of the 330 facilities surveyed by OOC in 1989, 67 facilities reported radionuclide data for produced sand. Of these 67 facilities reporting radioactivity data, 19 reported radionuclide concentration data in picocuries per gram (pCi/g) based on laboratory analysis, and 48 reported radiation exposure data in microroentgens per hour (microR/hr) from gamma readings. Naturally occurring radioactive materials (NORM) levels of the produced sand were found to be above either 30 pCi/g or 50 microR/hr for 17 of the 67 locations.[4] Table X-3 summarizes the radioactivity data collected during the OOC Survey.

TABLE X-2

AVERAGE OIL CONTENT IN PRODUCED SAND[11]

Cutting Box	Oil Content in Feed Sand[a] Oil & Grease (% Weight)[c]	Oil Content in Washed Sand[b] Oil & Grease (% Weight)[c]
A-222	3.95	0.99
11441	2.4	1.75
17631	1.55	1.47
11331	3.3	1.02
17071	2.2	1.10
A-194	4.3	1.45
A-113	5.95	2.2
11041	2.25	1.22
17451	3.45	1.18
A-148	3.15	3.33
501	No data	4.60

[a]Each sample is the composite of 5 samples taken from the cuttings box.
[b]Samples were collected as the material (feed from a specific cuttings box that had undergone processing) was discharged from the sand washer.
[c]Oil and grease analysis by APHA Method 503D.

TABLE X-3

SUMMARY OF RADIONUCLIDE DATA FOR PRODUCED SAND FROM OOC SURVEY[4]

Facility Location (Lease Number)	Ra-226 Concentration (pCi/g)	Ra-228 Concentration (pCi/g)
MC-311	39	64
MP-310	21	23
OCS-0742	56	51
OCS-0985	32	29
OCS-1181	144	180
OCS-1220	37	10
OCS-2116	9	9
OCS-2280	0	0
OCS-2428	1	1
OCS-3236	0	0
OCS-4232	12	12
OCS-4240	19	19
OCS-4734	1	1
OCS-9575	0	0
OCS-G-1294	85	84
OCS-G-1870	93	91
OCS-G-2638	41	39
OCS-G-3936	28	15
SL-1355	13	21

The Shell Offshore, Inc. produced sand washing study analyzed samples of unwashed and washed sand for radionuclides. The average concentrations of radionuclides in the produced sand before washing (this material had already undergone bulk solids separation in conjunction with tank cleaning operations) were 44.5 pCi/g and 42.1 pCi/g for ^{226}Ra and ^{228}Ra, respectively. The average concentrations of radionuclides in the washed produced sand were 39.9 pCi/g for ^{226}Ra and 38.7 pCi/g for ^{228}Ra.[11] Table X-4 presents the radionuclide data obtained in this study.

TABLE X-4

AVERAGE RADIOACTIVITY LEVELS IN PRODUCED SAND[11]

Cutting Box	Unwashed Sand[a]		Washed Sand[b]	
	Ra-226 (pCi/g)	Ra-228 (pCi/g)	Ra-226 (pCi/g)	Ra-228 (pCi/g)
A-222	21.5	26	20.33	22.83
11441	25	26	28.67	28.33
17631	44	40	19.5	18.5
11331	18.5	16.5	13.67	13.33
17071	33.5	33.5	33	30
A-194	26.5	26	29.5	30.5
A-113	57.5	44.5	45	37
11041	58	44	48.33	43
17451	15	14.5	20	18.67
A-148	145	143	121.33	122.67
501	No data	No data	119	106

[a] Each sample is the composite of 5 samples taken from the cuttings box. Each result represents a separate sample analyzed from the cuttings box.
[b] Samples were collected as the material (feed from a specific cuttings box that had undergone processing) was discharged from the sand washer.

Shell Offshore, Inc. conducted another sand washing study at a platform located in Bay Marchand, Louisiana (coastal subcategory). This study reported average concentrations of 93 pCi/g and 91 pCi/g for ^{226}Ra and ^{228}Ra respectively, in unwashed produced sand.[12]

2.4 CONTROL AND TREATMENT TECHNOLOGIES

The primary control and treatment technology for produced sand is preventing the sand from exiting the formation. Sand control is determined by the type of well completion. A specialized completion can prevent sand from being brought into the production line with the fluids.[5] The most up-to-date completion technology will prevent production solids from entering the production tubing, even in the most loose and unconsolidated formations.

The most common type of completion that prevents solids from entering the production tubing is a gravel pack completion. A gravel pack completion is a perforated cased hole completion that includes the placement of gravel, glass beads, or some other packing material between the production tubing and the casing. A screen or mesh is also placed between the production tubing and the casing. The gravel pack and screen serve as a filter to prevent solids from entering the production tubing. Older wells are typically open holed perforated completions in which nothing prevents solids from entering the production tubing with the fluid. Figure X-1 presents a schematic diagram of a closed hole perforated completion with gravel packing.

Gas producing wells are typically equipped with sand sensors which indicate the presence of sand in the gas stream. Sand sensors are commonly used in gas producing wells because sand flowing at high velocities with the produced gas will erode tubing, valves, and other process equipment. A sand sensor is a simple device that detects the sand particles hitting its surface. If sand is detected, an electrical signal will trigger an alarm to notify the operator. The operator can either alleviate the sand generation problem at the source or reduce the gas velocities to prevent the sensor from detecting the sand flow. The sand probes do not work in liquid streams and thus are not used on oil producing wells.[5]

2.4.1 BPT Technology

The management of produced sand wastes involves either treating the sand to meet the no free oil limitations and discharge to the surface waters or hauling the sand to shore for final disposal. Data from the 1989 OOC produced sand survey indicate that 32 percent of the sand collected is transported to shore for disposal and that 68 percent of the sand is discharged to the ocean. The Minerals Management Service (MMS) published an Environmental Impact Statement in 1989 that estimated 25 percent of the produced sand generated is transported to shore for disposal and 75 percent of the sand is discharged into the ocean. Since that time, MMS has issued interim guidelines placing additional restrictions on discharges of NORM contaminated produced sand.[13]

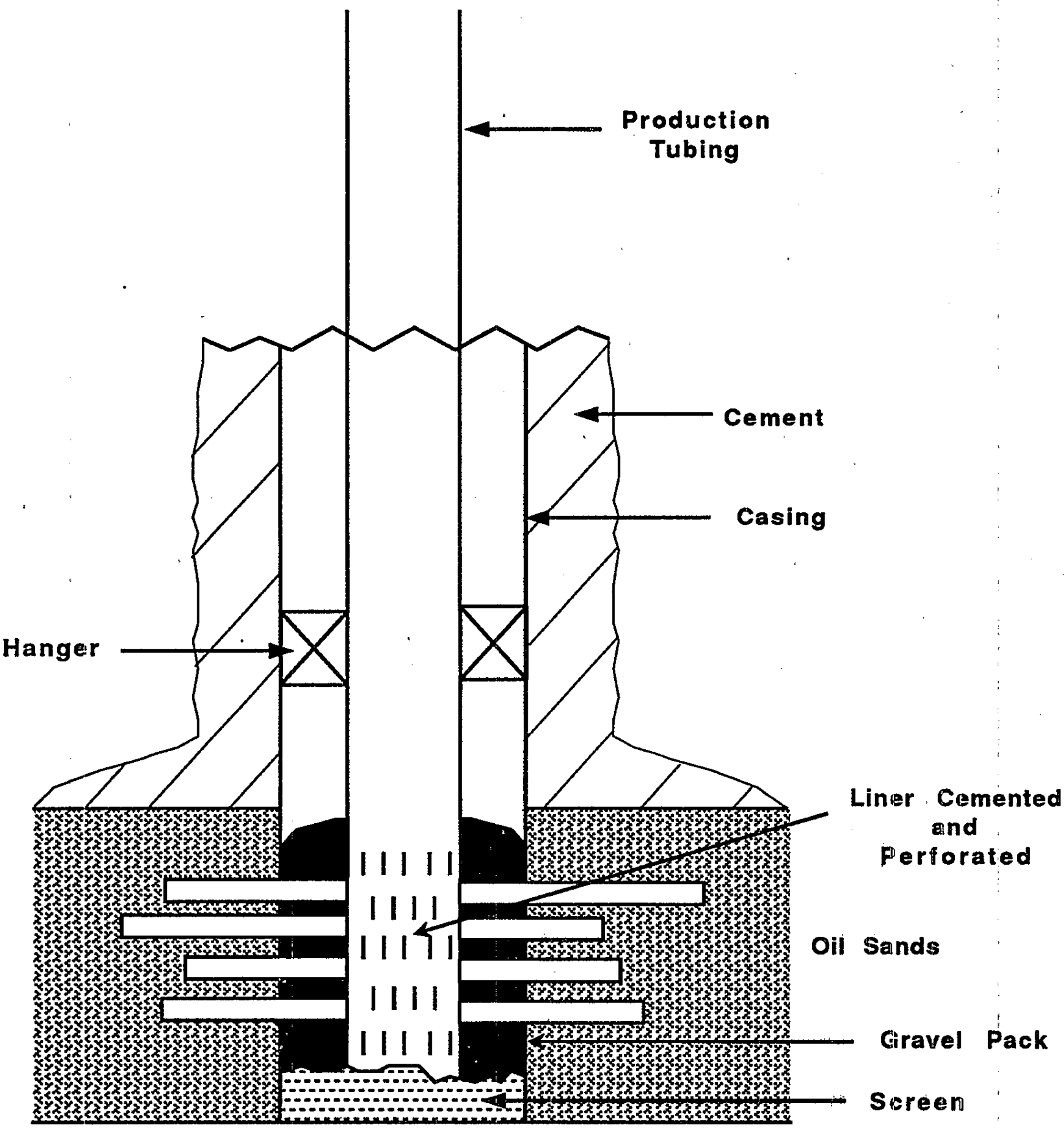

Figure X-1
Closed Hole Perforated Completion (With Gravel Pack)

In November 1990, the MMS Gulf of Mexico regional office responded to concerns of the presence of NORM in produced sand by issuing a Letter to Lessees (LTL) requiring all disposal to be approved by the MMS Gulf of Mexico office. Since the MMS Gulf of Mexico office was not approving offshore disposal, in essence this LTL placed a prohibition on the discharge of produced sand. A second LTL was issued in December 1991 which established interim guidelines for the disposal of produced sands. This LTL allows limited discharges of produced sand based on the following criteria[14]:

- The discharge is not in close proximity to a biologically sensitive area.
- The discharge complies with NPDES requirements.
- Samples of the material must be analyzed and demonstrate a radiation dose equivalent rate of less than 25 microR/hr above background.
- The volume to be discharged is less than 100 barrels per day.
- Samples must be analyzed by a laboratory capable of providing accurate results for concentrations of ^{226}Ra and ^{228}Ra and records concerning these data must be maintained and made available for review.
- Should the total radium discharged surpass 50,000 micro curies per quarter, the MMS regional office must be notified and all future discharges stopped until an assessment of the area is completed.

The MMS guidelines require the operator to submit an application for each facility where discharge is proposed. The application must include:

- Identity of the platform (well depth and oceanographic conditions)
- List of other facilities that will be discharging at the site
- Frequency and volume of discharge
- Preliminary measurements of radionuclide activity
- Program for monitoring, sampling, and record keeping
- Description and characterization of the material to be discharged
- Method of discharge.

Specific instructions have been provided regarding the above requirements. Even before enactment of the restrictions, some operators would opt for onshore disposal as opposed to treatment and discharge at the platform due to: costs, lack of space, lack of time, lack of proper equipment or type of hydrocarbons associated with the sand.[4]

2.4.2 Additional Technologies

Several methods were identified in the literature for treatment of produced sand and are included in this section. The treatment methods include: washing the material with water and detergents, mechanical separation, separation with solvents, and air flotation. Most of the sources consulted did not provide data or cleaning efficiencies for the treatment of produced sand.

The sand washing unit evaluated by Shell Offshore, Inc. consisted of mixing and settling tanks. The system was designed for operation at onshore locations and is larger than can be accommodated at some offshore platforms. This system achieved removals of approximately 60 percent of the oil associated with the produced sand. The system also generated centrifuge solids and washwater from the detergent cleaning operation that were transported to shore for disposal.[8] The unit processed 600 barrels of produced sand. The cost of the operation was $75,000 which included $6,000 for set-up and rig down, one and a half days of experimental operation, processing at a conservative flow rate and approximately $30,000 for soap. Treatment cost was $125 per barrel but the operator indicated that future operation of the treatment system will be approximately $60 per barrel.[12]

Several other treatment systems have been identified in the literature:

- A sand washer system that mechanically removes oil from produced sand consisting of a bank of cyclone separators, a classifier vessel, and another cyclone. Following treatment the sand is reported to have no trace of oil.[15] Actual data were not presented.
- A sand cleaning system consisting of two vertical two-phase separators. The initial separator is baffled and sand falls through to the second separator. The second separator contains a solvent layer to absorb oil from the sand grains.[15] Data were not presented.
- A produced sand disposal system consisting of a conventional cyclone and a cyclone with chemical and air injection that removes the oil by air flotation.[16]

Treatment of produced sand via mechanical washing has several drawbacks. The capital costs necessary to install a complete sand washing unit on a platform preclude the widespread installation of systems on platforms which only need to wash sand every 3 to 5 years. In addition to the equipment costs, current/ existing platform space is limited or not available for such equipment. The economics of platform additions for these systems would also limit widespread usage of sand washing technology. Sand washing does not always guarantee one-hundred percent discharge of the sand. Sands containing heavy oils cannot always be washed thoroughly enough to meet the permit discharge prohibition on free oil.

In these cases, the sand cannot be discharged and must be transported to shore for disposal. Since sand washing only reduces the oil content, produced sand that contains certain levels of Naturally Occurring Radioactive Material (NORM) must be transported to shore for disposal under the current MMS guidelines. In addition, sand washing can generate additional wastes, such as oily solids and oily water, which require further treatment and disposal.

If the produced sand can not be treated and discharged at the platform, then it is transported to shore for disposal. Cuttings boxes (15 and 25 barrel capacity), 55 gallon steel drums, and cone bottom portable tanks are used to transport the sand to shore via offshore service vessels.[4] According to the OOC, produced sand is disposed as a non-hazardous oilfield waste (NOW) according to State regulations. See Section VII.5.2.4 for a discussion of land disposal of NOW.

3.0 WELL TREATMENT, WORKOVER, AND COMPLETION FLUIDS

The definitions for well treatment, workover, and completion fluids (TWC fluids) are as follows:

- **Well Treatment Fluids** are "any fluid used to restore or improve productivity by chemically or physically altering hydrocarbon-bearing strata after a well has been drilled."
- **Workover Fluids** are "salt solutions, weighted brines, polymers, or other specialty additives used in a producing well to allow safe repair and maintenance or abandonment procedures."
- **Completion Fluids** are "salt solutions, weighted brines, polymers and various additives used to prevent damage to the wellbore during operations which prepare the drilled well for hydrocarbon production."

3.1 WELL TREATMENT, WORKOVER, AND COMPLETION FLUID VOLUMES

The volume of workover, well treatment, and completion fluids generated will vary depending on the type of well and the specific operation to be performed. Normally, workover and completion operations require at least one well volume of fluid since the fluids are contained within the well bore. For example, a 10,000 foot well with 3.5 inch diameter tubing contains a volume of less than 100 barrels.[17] The volume of workover and completion fluids will generally be the same before and after usage. More than one well volume (usually no more than three) are necessary for well treatment because the fluids may be lost to the formation. Treatment fluids can react with the formation and the volumes before and after use are not the same.

Typically, small volume discharges of fluids occur during the course of workover and completion operations in the same manner as drilling fluids discharges. In response to the 1991 proposal, several industry commenters indicate that workover and completion fluids that return to the surface as a discrete slug represent only a small portion of the fluids discharged during workover and completion operations.[18] Discharge volumes for specific workover, completion and well treatment activities are presented in Table X-5. This information indicates that discharges can range from 100 to 1,000 barrels. A report prepared for the American Petroleum Institute includes a summary of a survey of well servicing activity for 1988. This survey, presented in Table X-6, indicated that well treatment is performed on approximately 2 percent of the wells each year and approximately 4 percent of the wells are completed or recompleted each year. Other sources indicate that workover operations are performed on a well every three to five years.[18] Acidizing chemical data was obtained from four companies during the 1988 survey and is presented in Table X-7.

TABLE X-5

TYPICAL VOLUMES FROM WELL TREATMENT, WORKOVER, AND COMPLETION OPERATIONS[19]

Operation	Type of Material	Volume Discharges (barrels)
Completion and Workover	Packer Fluids	100 to 1000
	Formation Sand	1 to 50
	Metal Cuttings	<1
	Completion/Workover Fluids	100 to 1000
	Filtration Solids	10 to 50
	Excess Cement	<10
Well Treatment	Neutralized spent Acids	10 to 500
	Completion/Workover Fluids	10 to 200

Volumes of fluids used for workover, completion, and well treatment operations were collected for the Cook Inlet Discharge Monitoring Study. Table X-8 presents the volumes discharged during specific operations. Volume information was collected for a one year period. Ten discharge events were sampled during the course of the year. Each of the discharge events was from a single operation (either well treatment, workover, or completion) but discharges of the fluids may have occurred at several times during the course of the operations.[21]

TABLE X-6

SURVEY OF WELL SERVICING ACTIVITY[20]

	Gulf of Mexico	Offshore California	Alaska[a]
Total Number of Wells	10,614	2,090	355
Well Treatment (Stimulation)	259	28	3
Completions	162	36	30
Artificial Lift Installation/Repair	1,401	180	53
Tubular Repair	91	44	5
Recompletions	320	24	3
Total Number of Jobs	2,233	312	180

[a]These numbers are an estimate based on 25% of wells and service offshore. The data includes both the onshore and offshore subcategories.

TABLE X-7

DATA ON ACIDIZING IN THE GULF OF MEXICO[20]

	Company/Area				Total
	1	2	3	4	
Number of Wells	358	386	600	322	1,666
Number of Acid Jobs	19	19	80	27	145
Acids Used (gallons)[a]					
Hydrochloric	10,741	46,300	168,000	4,509	229,550
Hydrofluoric	0	8,363	61,320	0	69,683
Acetic	0	3,660	0	0	3,660
Total Acid	10,741	58,323	229,320	4,509	302,893
Average Job	565	3,070	2,867	167	2,089

[a]The various concentrations and types of acids have been converted to the equivalent volume of 15 percent hydrochloric acid (in gallons) based on the available hydrogen ion.

TABLE X-8

VOLUMES DISCHARGED DURING WORKOVER, COMPLETION, AND WELL TREATMENT OPERATIONS FROM THE COOK INLET DMR STUDY[21]

Type of Job	Workover	Completion	Well Treatment	Acid	Clean Out Tubing
Volumes Discharged (barrels)	600 600 400 100 1,111 492 1,200 670	390 75 310 303 50 50 25 75 25 1,295 740 50	178.6 238.1 35.7 71.4 20 93	10.8 320.8 25 173	12 148
Minimum	100	25	20	10.8	12
Maximum	1,200	1,295	238.1	25	148
Average	647	282	106	132	80

3.2 WELL TREATMENT, COMPLETION, AND WORKOVER FLUIDS CHARACTERISTICS

3.2.1 Well Treatment Fluids

In general, well treatment fluids are acid solutions. Acids used include: hydrochloric acid (HCl), hydrofluoric acid (HF) and acetic acid ($C_2H_4O_2$). Concentrations of HCl in water range from 15 to 28 percent. A mixture of hydrochloric and hydrofluoric acid is also used and is referred to as "mud acid."[17] Mud acid mixtures are 12 percent HCl and 3 percent HF in water. Acids are selected based on formation solubility, reaction time, and reaction products. The acid reactions are temperature dependent and temperature increases can decrease the depth of acid penetration.[22]

A well treatment job involves a series of several solutions to be pumped down hole: a pre-flush solution, the acid solution, and a post-flush or "chaser" solution. The pre-flush solution is generally 3-5 percent ammonium chloride (NH_4Cl) and forces the hydrocarbons back into the formation to prepare for stimulation. The acid solution is then pumped downhole. Following the acid solution is a post-flush of ammonium chloride that forces the acid further into the formation.[20] The solutions remain in the formation for 12 to 24 hours and are then pumped back to the surface.[17]

Common well treatment fluids include: hydrofluoric acid, hydrochloric acid, ethylene diaminetetraacetic acid (EDTA), ammonium chloride, nitrogen, methanol, xylene, toluene. Well treatment fluids may include additives such as corrosion inhibitors, mutual solvents, acid neutralizers, diverters, sequestering agents, and antisludging agents.[19] Additives include: iron sequestering agents, corrosion inhibitors, surfactants, viscosifiers, and fluid diverters.[23] The purpose of the additives can be for: reducing the leak-off rate, increasing the propping agents carried by the fluid, reducing friction, and preventing the aggregation and deposition of solid particles.[20] A corrosion inhibitor is always used during an acid stimulation job because the acids used are extremely corrosive to the steel piping and equipment.[17,24] Table X-9 lists some of the typical chemicals used during well treatment.

TABLE X-9

WELL TREATMENT CHEMICALS[25]

Type of Fluid or Purpose	Constituents	Dose
Fracture or matrix acidizing agent	Acrylamide polymer Gelling agent Reducing agent Acid	0.1 to 1.5% by weight 0.5 to 30% by weight of polymer used 200% of stoichiometric amount of gelling agent used 10% by weight
Acid stimulation agent	Vinyl pyrolidine copolymer HCl Water	1% by weight 8% by weight 91% by weight
Acidizing fluid	Oxyalkylated acrylamidoalkane-sulfonicacid polymer	1% by weight in 15% HCl
Acid fracturing agent	Dialkyldimethyl-ammonium chloride polymers in acid solution	0.1 to 1% by weight polymer, 5 to 15% HCl solution
Self breaking acidizing emulsion	C_6-C_{18} primary amine Diethanolamide of C_8-C_{18} fatty acid Kerosene Acid solution	0.01 to 0.5% by weight 0.02 to 1.0% by weight 25 to 35% by volume 25 to 38% HCl solution
Acid precursor	Carbon tetrachloride	10% CCl_4 90% water
Acidizing of siliceaous strata	Ammonium fluoride	1 to 10% by weight fluoride ion concentration
Sequestering additive for iron and aluminum in acid stimulation	Levulinic acid Citric acid HCl solution	10 to 400 lb/1000 gallon 10 to 400 lb/1000 gallon 15% HCl solution
Fracturing agent	Hydroxypropyl cellulose Poly (maleic anhydride) alkyl vinyl ether	1% 3%
High temperature fracturing agent	Aluminum salt of phosphate ester in kerosene	1% by weight in kerosene
Acid stimulation	Acetic acid	20 to 30%
Acid fracturing	Acid in oil emulsion	10 to 28%

3.2.2 Workover and Completion Fluids

Workover and completion fluids are similar in nature and are typically a variety of clear brine. Packer fluids are workover or completion fluids which are left in the annulus between the well casing and tubing at the conclusion of the operation.[18] Specific fluids are used during completion and workover operations to seal off the producing formation to prevent fluids and solids loss to the formation. The formation is sealed by the disposition of a thin film of solids over the surface of the formation. These solids are called bridging agents.[25] The bridging agents are oil or acid soluble and dissolve at the cessation of workover or completion operations to enable oil or gas to be produced from the well.[26] Commonly used bridging agents are: ground calcium carbonate, sodium chloride, oil soluble resins, and calcium lignosulfonates.[27] The fluids are selected to be compatible with the formation to minimize damage to the formation and should perform the following functions:[19,27,28]

- Control subsurface pressures
- Maintain hole stability
- Transport solids to the surface
- Installation of packer fluids
- Keep solids in suspension
- Minimize corrosion
- Remain stable at elevated temperatures.

Workover and completion fluids can be divided into two broad classifications: water-based and oil-based fluids. There are three types of water-based fluids: brine water solutions, modified drilling fluids, and specially designed drilling fluids.

Brine fluids are comprised of inorganic salts dissolved in water. This combination yields a solids-free fluid with sufficient density to control sub-surface pressures.[27] Brine solutions have a density ranging from 8.5 pounds per gallon (ppg) for seawater to 19.2 ppg for zinc bromide/calcium bromide fluids.[28] Table X-10 lists some of the more common brine solutions and their densities. Disadvantages of brine fluids are: expense (which can reach $800/barrel), the generation of precipitates in the formation at high pH or when contaminants are present, loss of large volumes of fluid to the formation, limited lifting capacities, poor suspension properties, and temperature sensitivity.[27]

TABLE X-10

COMMON BRINE SOLUTIONS USED IN WORKOVER AND COMPLETION OPERATIONS[27]

Brine Solution	Density (lb/gallon)[a]
Potassium Chloride	9.7
Sodium Chloride	10.0
Sodium Bromide	12.5
Calcium Chloride	11.6
Calcium Bromide	11.6 to 14.2
Calcium Chloride-Calcium Bromide	11.6 to 15.1
Zinc Bromide-Calcium Bromide-Calcium Chloride	15.1 to 19.2

[a]Densities given are the maximum density except where a range is provided.

Modified drilling fluids contain the necessary additives to achieve the basic functions of a completion or workover fluid. These fluids are economical to use since they are usually readily available. The disadvantages of modified drilling fluids is their high solids content (both compressible and incompressible solids). The high solids content can result in: hydration and/or migration of formation clays and silts, emulsion or water blocking, and permanent formation damage.

Specially designed fluids consist of inorganic brines with the addition of: polymers, acids, water, or oil-soluble materials needed to formulate a fluid with the proper viscosity, weight support, and fluid loss control. These fluids are used where additional clay inhibition is required. Two of the available polymers used are hydroxyethyl cellulose (HEC) and xanthan gum. Problems associated with specially designed systems include poor temperature stability, foaming, and corrosivity.[27]

There are two types of oil-based fluids: true oil fluids and invert emulsion fluids. The advantages of oil-based fluids include: temperature stability, density range, maximum inhibition, minimum filtrate invasion, and non-corrosive. Disadvantages include toxicity and the potential to: damage environmentally sensitive areas, change the wettability of the formation, cause emulsion blocks, or damage dry gas sands.[27]

The drilling mud tanks are used to mix and circulate workover and completion fluids. The fluids are circulated to remove unwanted materials and to maintain pressure.[17] Solids control must be maintained in workover and completion fluids so that the formation is not irreversibly plugged in the vicinity of the wellbore.

World Oil publishes a yearly guide of drilling completion and workover fluids. The guide lists specific additives to the basic fluid and includes the product name, tradename, description of material, recommended uses, product function and the company from which they may be obtained. In all, 1,226 additives were recommended for use in workover operations and 1,157 of these additives were also recommended for other uses. The primary functions of additives in workover fluids were as corrosion inhibitors, viscosifiers, and filtration reducers. The corrosion inhibitors such as hydrated lime and amine salts are added to the fluid to control corrosion. The viscosifiers are added to increase the viscosity. The filtrate reducers are added to reduce fluid loss to the formation and can include bentonite clays, sodium carboxymethylcellulose, and pregelatinized starch.[29] Table X-11 identifies specific additives to completion and workover fluids.

TABLE X-11

ADDITIVES TO COMPLETION AND WORKOVER FLUIDS[19]

Type of Additive	Specific Additives
Viscosifiers	Guar Gum Starch Xanthan Gum Hydroxyethyl Cellulose Carboxymethyl Cellulose
Fluid Loss Control	Calcium Carbonate Graded Salt Oil Soluble Resins
Corrosion Inhibitors	Amines Quaternary Ammonia Compounds

Several sources indicate that well completion and workover fluids may include hydroxyethyl cellulose, xanthan gum, hydroxypropyl guar, sodium polyacrylate, filtered seawater, calcium carbonate, calcium chloride, potassium chloride, and various corrosion inhibitors and biocides, zinc bromide, calcium bromide, calcium chloride, hydrochloric acid, and hydrofluoric acids.[23]

3.2.3 Chemical Characterization of Well Treatment, Workover, and Completion Fluids

Samples of workover, completion and well treatment fluids were collected and analyzed for the Cook Inlet Discharge Monitoring Study conducted in 1987. The study was a cooperative effort between the U.S. EPA Region X and seven oil and gas companies. The specific objective of the study was to determine the type, composition and volume of discharges from workover, completion, and well treatment operations. Samples were collected of fluids during five workover operations (one using weak acid, EDTA), two completion operations, and three well treatments using acid.[21]

The samples collected during the Cook Inlet Discharge Monitoring Study were analyzed for pH, oil and grease, dissolved oxygen, BOD, COD, TOC, salinity, zinc, cadmium, chromium, copper, mercury, and lead. Table X-12 summarizes the analytical results from the Cook Inlet Discharge Monitoring Study.

The Three Facility Study collected well treatment fluids from two wells being acidized at the THUMS facility.[17] Table X-13 presents the analytical results of the well treatment fluids sampled at the THUMS facility.

The American Petroleum Institute's report entitled Exploration and Production Industry Associated Wastes Report presents metals analysis for a fracturing fluid sampled in 1982. The frac fluid analyzed was a water based mixture of polymers, salts, gels and miscellaneous chemicals from a production facility in California. The fluid contained 25 to 30% fine sands used as a propping agent. A propping agent is a granular substance carried in suspension by the fracturing fluid that serves to keep the cracks open when the fracturing fluid is withdrawn after a fracture treatment. The total volume of fluids used including a separate displacement was 840 barrels. Table X-14 contains analytical data for metals analyses of this fluid.[17]

TABLE X-12

ANALYTICAL RESULTS FROM THE COOK INLET DISCHARGE MONITORING STUDY

	Lab pH	Field pH	O&G	Field D.O.	BOD	COD	TOC	Salinity	Zn	Cd	Cr	Cu	Hg	Pb
Units	SU*	SU*	mg/l	ppm	mg/l	mg/l	mg/l	ppt	mg/l	mg/l	mg/l	mg/l	mg/l	mg/l
Workover Fluids	6.3	6.5	36	1	690	1,170	306	16.7	NA	NA	NA	NA	NA	NA
	4.1	4.1	74	0.2	460	1,820	1,700	16.2	NA	NA	NA	NA	NA	NA
	NA	NA	47	NA	NA	NA	NA	NA	2.2	0.21	3.3	1.3	0.0019	0.3
	7.9	7.2	21	0.4	660	1,130	249	22.78	0.13	ND*	0.12	ND*	ND**	ND*
	6.6	6.9	21	0.3	680	1,270	321	21	0.16	ND*	ND*	ND*	ND**	ND*
	6.7	7.1	0.34	2.6	3.4	236	23	17.65	NA	NA	NA	NA	NA	NA
	7.2	7	9.4	0.4	400	>1,500	203	27.81	NA	NA	NA	NA	NA	NA
	6.7	6.9	21	2.8	51	408	61	24.16	NA	NA	NA	NA	NA	NA
	NA	1.4	66	NA	NA	NA	NA	NA	0.68	0.142	ND*	2.8	0.00044	0.35
	7.5	7.6	12	0.1	660	1010	289	30.63	0.015	ND***	ND*	ND*	ND**	ND*
	7.5	7.5	14	0.2	630	965	294	30.63	0.01	ND***	ND*	ND*	ND**	ND*
	7.4	7.4	16	0.2	720	1,410	302	29	0.036	ND***	ND*	ND*	ND**	ND*
	NA	1.6	23	NA	NA	NA	NA	NA	0.175	0.0063	0.04	0.18	0.00074	0.05
	6.8	7.2	13	0.2	600	1,080	350	27.36	0.017	ND***	ND*	ND*	ND**	ND*
	6.7	7.3	11	0.1	600	1,035	304	25.72	0.02	ND***	ND*	ND*	ND**	ND*
	6.7	7.3	8.1	0.1	560	1080	307	25.72	0.012	ND***	ND*	ND*	ND**	ND*
	7.2	7.2	5.6	0.4	570	1,230	115	30.01	NA	NA	NA	NA	NA	NA
	7.2	7	2.2	0.1	865	980	70	29.51	NA	NA	NA	NA	NA	NA
	7	7.1	1.9	0.5	645	1,000	119	29.18	NA	NA	NA	NA	NA	NA
Completion Fluids	7.1	7.1	6.1	4.7	108	590	90	25.76	NA	NA	NA	NA	NA	NA
	8.6	8.5	0.23	6.2	6	865	4	2.14	NA	NA	NA	NA	NA	NA

*pH reported in standard units
NA = Not analyzed
ND* = Not detected (detection limit at 0.01)
ND** = Not detected (detection limit at 0.0002)
ND*** = Not detected (detection limit at 0.002)

TABLE X-13

ANALYSIS OF FLUIDS FROM AN ACIDIZING WELL TREATMENT[17]

Analyte	Concentration (μg/l)	Analyte	Concentration (μg/l)
Aluminum	53.1	Aniline	434
Antimony	<3.9	Naphthalene	ND
Arsenic	<1.9	o-Toluidine	1,852
Barium	12.6	2-Methylnaphthalene	ND
Beryllium	<0.1	2,4,5-Trimethylaninine	2,048
Boron	31.9	Oil and Grease	619
Cadmium	0.4	pH	2.48
Calcium	35.3		
Chromium	19		
Cobalt	<1.9		
Copper	3.0		
Iron	572		
Lead	<9.82		
Magnesium	162		
Molybdenum	<0.96		
Nickel	52.9		
Selenium	<2.9		
Silver	<0.7		
Sodium	1,640		
Thallium	5.0		
Tin	6.66		
Titanium	0.68		
Vanadium	36.1		
Yttrium	0.19		
Zinc	28.5		

TABLE X-14

METALS ANALYSIS OF A FRACTURING FLUID[17]

Analyte	Concentration (mg/kg)*
Antimony	44.83
Arsenic	<0.002
Barium	7.245
Beryllium	0.06
Cadmium	0.13
Chromium	0.065
Cobalt	0.18
Copper	0.395
Lead	2.27
Mercury	0.0045
Molybdenum	0.10
Nickel	0.23
Selenium	0.106
Silver	0.03
Thallium	0.30
Vanadium	0.10
Zinc	2.1
pH	5.0
Specific gravity	1.60
% Solids	10.91%

*Mean concentration of duplicate samples except for pH, specific gravity and % solids.

3.3 Well Treatment, Completion, and Workover Fluids Control and Treatment Technologies

3.3.1 BPT Technology

The current BPT requirement for TWC fluids is "no discharge of free oil" to receiving waters, as determined by the static sheen test. Methods for treatment and disposal include:

- Treatment and disposal along with the produced water
- Neutralization for pH control and discharge to surface waters
- Reuse
- Onshore disposal and/or treatment.

Conflicting information is available regarding the treatment and disposal of well treatment, workover, and completion fluids with the produced water. Some sources indicate the infeasibility of commingling due to technical limitations while other sources indicate routine commingling without any negative effects on the performance of the produced water treatment system. A key factor of whether the TWC fluids are or are not commingled is how they resurface from the formation. If the TWC fluid surfaces as a discrete slug, it can be easily separated from the production fluid stream. Once separated, the TWC fluid must meet the no free oil requirements upon discharge. If the TWC fluid cannot meet the no free oil requirement, it must either be treated or brought to shore for treatment and/or disposal. However, if the TWC fluid is not present as a discrete slug, separation may be difficult. Several commenters reported that most completion and workover fluid discharges occur as small volume discharges several times during the completion or workover operations (normally lasting seven to thirty days).[18] The following paragraphs present information on facilities that do and do not commingle.

One source indicates that these fluids are not typically processed with the produced water in offshore operations and that operating practices in Cook Inlet are not representative of offshore operations (facilities in Cook Inlet commingle TWC fluids with produced water). Other sources have indicated that the processing of these fluids along with the produced water is infeasible. Due to short residence times, offshore produced water treatment systems are sensitive to changes in the influent which would occur if large, concentrated slugs of TWC fluids are introduced to the system. EPA believes however, that corrosion problems can also result if oxygen is introduced into the produced water treatment system along with the TWC fluids.[18]

According to one industry report, TWC fluids can be effectively treated in the produced water treatment system if commingling is performed in such a manner that the treatment system is not subjected to concentrated slugs of TWC fluids.[20] Operators in Alaska also treat and dispose of these fluids with their produced water. In California, facilities commingle the workover, completion and well treatment fluids with the produced water.[17]

Generally, economics dictates recycling and reusing weighted workover and completion fluids. Workover and completion fluids can be reused 2 to 3 times depending on the amount of oil and grease build-up. Inexpensive workover and completion fluids consisting primarily of filtered seawater are typically not reused. Treatment fluids are not reused because they react with the formation and lose their treatment ability.[17]

3.3.2 Additional Technologies Considered

Additional controls considered for BAT and NSPS levels of control for this rulemaking are limitations on oil and grease content. The technology basis for oil and grease limitations on TWC fluids is commingling and treating with the produced water. A detailed discussion of produced water BAT and NSPS treatment technology is presented in Section IX.

Information contained in a 1989 industry report indicate that for operations involving 10 or more wells per platform, the produced water flow rates and the treatment systems are large enough to sufficiently buffer the introduction of the TWC fluids into the produced water treatment system such that upsets will not occur.[30] Typically, only one well is treated at a time due to the manpower and equipment requirements. Therefore, the volumes of TWC fluids from this one well are small relative to the volume of the produced water from the remaining wells. Those TWC fluids unable to be processed with the production stream, can be processed through a test separator (standard equipment on platforms). Production facilities piping the bulk production fluids to shore for separation would be unlikely to suffer treatment system upset because the volumes of produced water from other platforms being treated at the same onshore facility would be much greater in relation to the TWC fluid volume. Even, facilities with less than 10 wells per platform should be able to commingle TWC fluids in the produced water treatment system if the fluids are captured and commingled at such a rate to prevent system upset.

4.0 DECK DRAINAGE

4.1 DECK DRAINAGE SOURCES

Deck drainage includes all water resulting from spills, platform washings, deck washings, tank cleaning operations and run-off from curbs, gutters, and drains including drip pans and work areas.

4.2 DECK DRAINAGE VOLUMES

EPA evaluated Discharge Monitoring Reports (DMRs) for deck drainage discharges from 32 oil companies located in the Gulf of Mexico.[31] The DMR data spans two years from May 1, 1981 through April 30, 1983 and consists of deck drainage monitoring data from oil and gas production facilities. The DMR data reports monthly samples taken by the operators. The data do not indicate the location of where the samples were taken, the treatment of the waste stream prior to sampling, or the analytical method of determining oil & grease. Table X-15 presents the volumes of deck drainage compiled from the DMR data.

TABLE X-15

VOLUMES OF DECK DRAINAGE FROM OFFSHORE RIGS IN THE GULF OF MEXICO[31]

Year	Number of Platforms	Average Monthly Volume		Maximum Daily Volume	
		Range (bbl/day)	Average (bbl/day)	Range (bbl/day)	Average (bbl/day)
1981 - 1982	425	0 - 4,276	65	0 - 4,700	106
1982 - 1983	950	0 - 4,206	50	0 - 9,698	90

4.3 DECK DRAINAGE CHARACTERISTICS

Oil and grease are the primary pollutants identified in the deck drainage wastestream. In addition to oil, various other chemicals used in drilling and production operations may be present in deck drainages. The chemicals may include drilling fluids, ethylene glycol, lubricants, fuels, biocides, surfactants, detergents, corrosion inhibitors, cleaners, solvents, paint cleaners, bleach, dispersants, coagulants, and any other chemical used in the daily operations of the platform.[32]

The DMR from the Gulf of Mexico contained oil and grease concentrations of deck drainage discharges. Table X-16 presents the monthly averages of deck drainage oil and grease concentrations for the two years evaluated.

TABLE X-16

CHARACTERISTICS OF DECK DRAINAGE FROM OFFSHORE PLATFORMS[31]

Oil and Grease in Deck Drainage (mg/l)				
	Monthly Average		Daily Maximum	
	Range	Average	Range	Average
1981-82 (19 Sites)	5-47	22	19-72	51
1982-83 (117 Sites)	2-183	28	5-1363	75

The Three Facility Study collected samples of untreated and treated deck drainage from the THUMS facility and the Shell Beta Complex. The range of pollutant concentrations in untreated deck drainage are presented in Table X-17.

Table X-18 presents TSS and oil and grease data from the deck drainage collection system of the THUMS facility before treatment in a skim basin. See Section X.5.4 for a description of the deck drainage system at the THUMS facility.

TABLE X-17

POLLUTANT CONCENTRATIONS IN UNTREATED DECK DRAINAGE[33,34]

Pollutant	Range of Concentration	Pollutant	Range of Concentration
Temperature (°C)	20-32		
Conventionals (mg/l)			
pH	6.6-6.8		
BOD	< 18-550		
TSS	37.2-220.4		
Oil & Grease	12-1,310		
Nonconventionals			
TOC (mg/l)	21-137		
Aluminum (μg/l)	176-23,100		
Barium	2,420-20,500		
Boron	3,110-19,300		
Calcium	98,200-341,000		
Cobalt	< 20		
Iron	830-81,300		
Magnesium	50,400-219,000		
Manganese	133-919		
Molybdenum	< 10-20		
Sodium	151×10^4-568×10^4		
Tin	< 30		
Titanium	4-2,030		
Vanadium	< 15-92		
Yttrium	< 2-17		
Priority Metals (μg/l)		**Priority Organics (μg/l)**	
Antimony	< 4- < 40	Acetone	ND-852
Arsenic	< 2- < 20	Benzene	ND-205
Beryllium	< 1-1	m-Xylene	ND-47
Cadmium	< 4-25	Methylene chloride	ND-874
Chromium	< 10-83	N-octadecane	ND-106
Copper	14-219	Naphthalene	392-3,144
Lead	< 50-352	o,p-Xylene	105-195
Mercury	< 4	Toluene	ND-260
Nickel	< 30-75	1,1-Dichloroethene	ND-26
Selenium	< 3-47.5		
Silver	< 7		
Thallium	< 20		
Zinc	2,970-6,980		

*Ranges of four samples, two each, at two of the three facilities in the three-facility study.

TABLE X-18

DATA FROM SUMP EFFLUENT TAKEN AT THUMS ISLAND GRISSOM FACILITY[33]

Sample Date	Temp. (°C)	pH	TSS (mg/l)	Oil and Grease (mg/l)
June 26, 1989	32	6.8	37.2	199
June 28, 1989	30	6.6	208.4	1310

Table X-19 presents data of untreated and treated deck drainage collected at the Shell Beta Complex. The data of the treated deck drainage represents samples collected from the skim pile. See Section X.5.4 for a description of the deck drainage system at the Shell Beta Complex.

TABLE X-19

DATA FROM DECK DRAINAGE TAKEN AT SHELL BETA COMPLEX[33,34]

Sample Date	Untreated Deck Drainage				Treated Deck Drainage			
	Temp. (°C)	pH	TSS (mg/l)	Oil & Grease (mg/l)	Temp. (°C)	pH	TSS (mg/l)	Oil & Grease (mg/l)
June 20-21, 1989	24	6.7	65.6	12	19	6.7	84.4	76
June 21-22, 1989	20	6.6	220.4	286	17	6.6	580.0	1090

4.4 DECK DRAINAGE CONTROL AND TREATMENT TECHNOLOGIES

4.4.1 BPT Technology

BPT limitations for deck drainage prohibit the discharge of free oil. Typical BPT technology for compliance with this limitation is a skim pile which facilitates gravity separation of any floating oil prior to discharge of the deck drainage.

A typical platform is equipped with drip pans and gutters to collect deck and drilling floor drainage. The drainage is collected in a sump where the water and oil are separated by a gravity separation process. Oil in the sump tank is recovered and transferred to the oil treater of the produced water treatment system. The product is then transferred to shore via a pipeline. Figure X-2 is a schematic of a generic production platform flow system. The water from the sump is discharged to the ocean via a skim pile. Skim piles remove that portion of oil which quickly and easily separates from

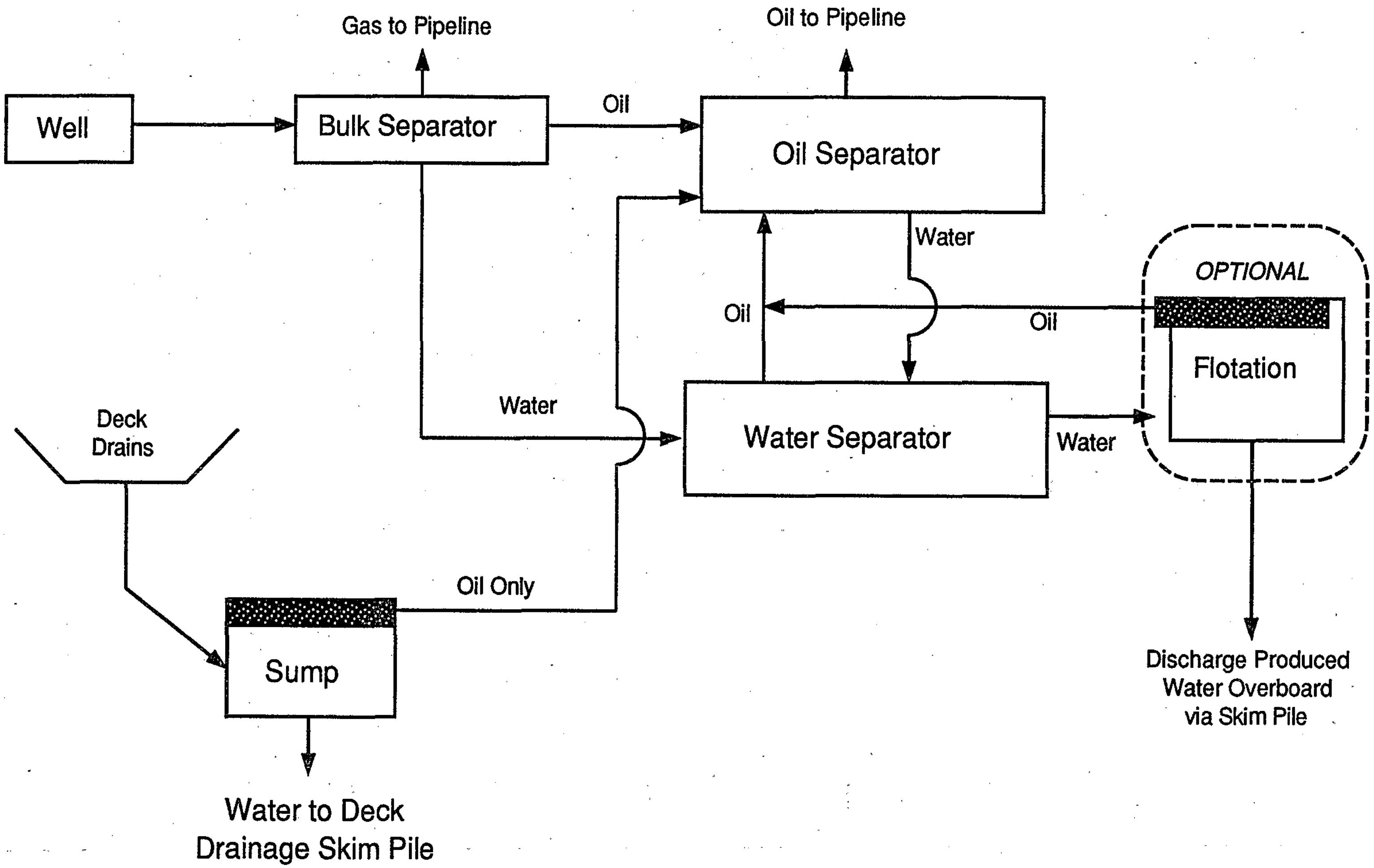

Figure X-2
Produced Water Treatment System

water. They are constructed of large diameter pipes containing internal baffled sections and an outlet at the bottom. During the period of no flow, oil will rise to the quiescent areas below the underside of inclined baffled plates where it coalesces. See Section IX.5.1.6 for a description of a typical skim pile. Due to the differences in specific gravity, oil floats upward through oil risers from baffle to baffle. The oil is collected at the surface and removed by a submerged pump. These pumps operate intermittently and will move the separated oil to a sump tank. Oil recovered in the sump is combined with production oil.

The following chemical and physical characteristics are major factors in the performance of treatment technologies:[35]

- **Salt content**: usually a high salt content facilitates the separation, some processes do not work well with a low salt content
- **Solid content**: the presence of solid particles in the water usually precludes the use of fibrous bed separation techniques; tank cleaning leads to high solids.
- **Chemical content**: chemicals used in oil production (e.g. biocides, corrosion inhibitors) will lower the size of oil droplets, creating separation problems.
- **Oil content**: depending on the oil content a one-step or two-step process is necessary.
- **Temperature**: a high temperature increases the separation but also increases the solubility of oil compounds in water.
- **Oil density**: the lighter the oil, the easier the separation.
- **Oil viscosity and Wax Content**: interfere with filtering or coalescing bed plates.
- **Oil droplet size**: the larger the droplet size, the easier the separation.

In the Gulf of Mexico, treatment practices for deck drainage vary. Some deck drainage discharge systems collect the flow from all drains and route it to a skim pile which is designed to meet the BPT prohibition of free oil discharges. Optimum performance of a skim pile is based on a 20 minute residence time. Other deck drainage discharge systems take all drains to a sump tank located below the main deck. Oil is separated by gravity and pumped to the oil treating system while water is then routed to a skim pile for discharge to the sea.[35]

Some platforms in Cook Inlet, Alaska collect crank-case oil separately and oil-based muds are diverted from the platform drain systems for onshore separation and treatment. Deck drainage is either piped to shore with the produced water waste stream and treated by gas flotation or gravity separated on the platform and treated by gas flotation to an average of 25 mg/l oil and grease.[36]

In California, some platforms mix deck drainage water with produced water and pipe it to shore for treatment and disposal. On other platforms the deck drainage is mixed with produced water, filtered and reinjected.[35] At the Beta Complex, evaluated in the Three facility Study, all waters from the deck drains, which may originate from washdowns, spills, rain, or equipment drains, are treated by the emergency sump system and discharged to the skim pile. Figure X-3 presents a detailed schematic of the emergency sump system. Water discharged from the emergency sump system and emergency discharges from the produced water system are directed to the skim pile.

A sampling trip was performed by EPA in April 1991 to collect data to evaluate the produced water treatment system located on Marathon Oil's Eugene Island 349-B platform in the Gulf of Mexico.[37] Deck drainage was not sampled on this sampling trip; however, observations of the deck drainage treatment system are presented here to provide additional information regarding site-specific treatment practices. The deck drainage at this site is collected by deck drains in several places on the drilling deck and by gutters that line the perimeter of the drilling deck. The drainage lines are all connected together and piped to the pre-sump. The pre-sump is a small gravity separator with an oil collection system. The capacity of the pre-sump is approximately 40 barrels. The oil collected in the pre-sump is pumped to the chem-electric oil treatment unit. The water is piped to a skim pile for discharge to the sea.

One of the platforms examined in the Cook Inlet Discharge Monitoring Study was the Phillips Petroleum Company's Platform Tyonek. On this platform all produced water and deck drainage water are commingled in a slop tank. Waters from the slop tank are pumped to the balance tank in batches. Chemicals are added and circulated to extract the hydrocarbon from the water. The mixture is retained in the tank for a period of time to allow the oil and water to separate by gravity. The water is discharged to the sea. The remaining liquid is transferred to another slop tank for holding and reprocessing. Sampling results indicated a mean average oil and grease content of 3.8 milligrams per liter.

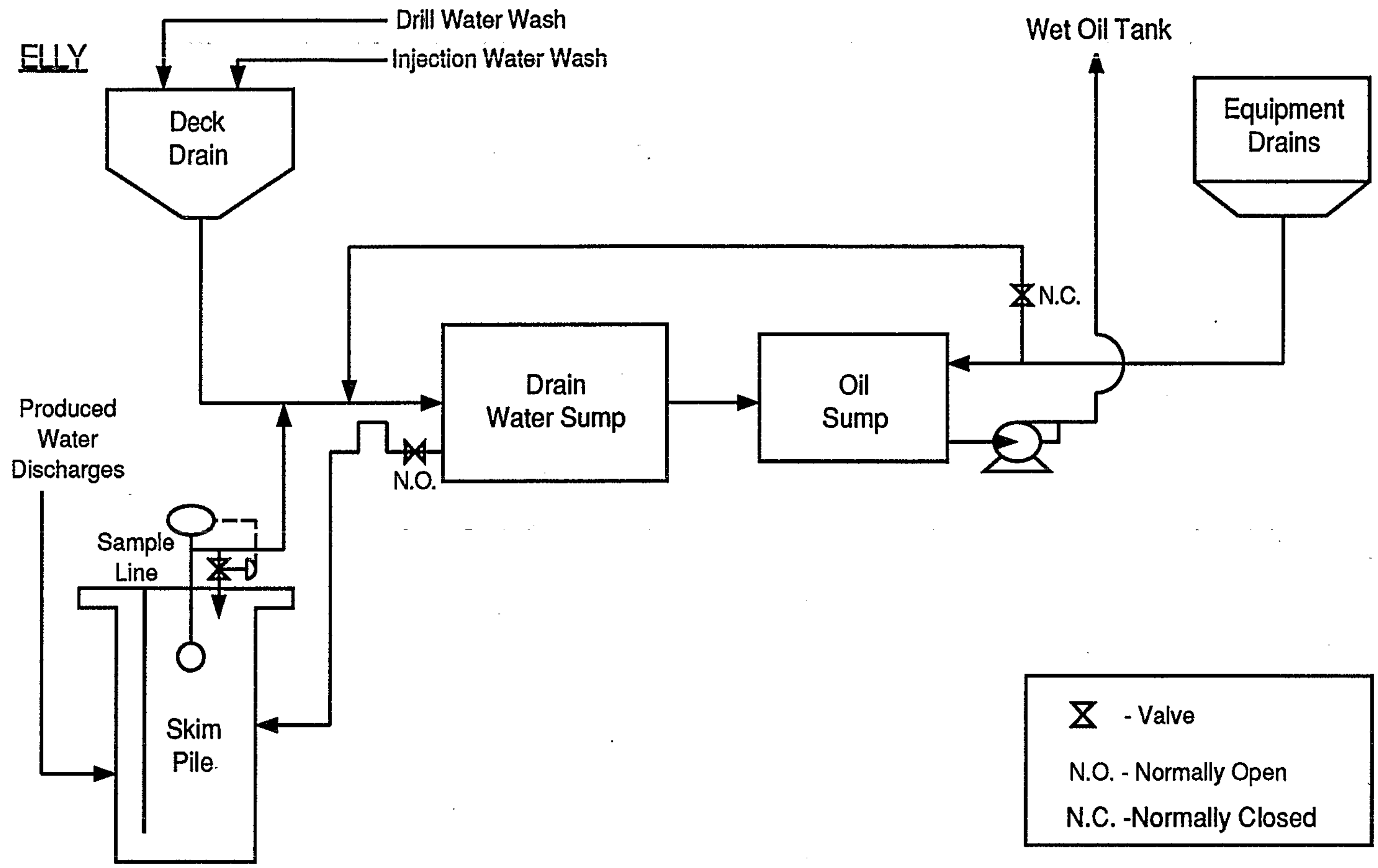

Figure X-3
Shell Western E&P Inc.–Beta Complex Emergency Sump System Flow Diagram

A study in Region II found that for deck drainage treatment systems to operate properly, three basic components were necessary:

1. Settling tanks of sufficient capacity
2. Desander (hydrocyclone)
3. Oil-water separation unit (type not specified).

If these conditions were met, the effluent oil and grease concentrations were below a monthly average of 30 mg/l and a daily maximum of 52 mg/l.

4.4.2 Additional Deck Drainage Technologies

As part of this rulemaking, EPA has considered BAT and NSPS limitations based on commingling deck drainage with the produced water. An example of this practice can be found on Texaco/Superior's platform "A" in Cook Inlet, Alaska. All deck drainage is collected and drained to the production surge tank where it combines with produced fluids and is also shipped to shore. Various studies indicate that commingling, as it is defined above, does not usually occur. There is relatively little data supporting the use of this practice. More often, the deck drainage is diverted to a sump tank. The water is gravity separated and transferred to a skim pile where further separation occurs prior to discharge overboard. The oil removed in the sump tank is pumped to an oil separator in the produced water treatment system. It was found, through a telephone conversation with a senior process engineer in Cook Inlet, that mixing of the deck drainage and produced water is only conducted when the deck drainage stream fails the visual sheen test.[38] Rather than co-mingling the deck drainage with the produced water treatment system at the facility, the deck drainage wastewater is diverted and pumped to shore along with produced water for treatment. A corrosion inhibitor is usually added to compensate for the introduction of the oxygen-enriched deck drainage water.

The whole deck drainage waste stream is not usually commingled with the produced waste water stream because:[35]

- The resulting flow variations would seriously upset the produced water treatment facility.
- Deck drainage water, saturated with oxygen, when combined with the salt content of the produced water could result in higher corrosion rates in the equipment. Also, the oxygen may combine with iron and sulfide in the produced water can causing the formation of solids which foul treatment equipment;

- Detergents, used for washing oil off the decks, cause emulsification of oil and seriously upset the produced water treatment processes.

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

5.0 DOMESTIC WASTES

5.1 DOMESTIC WASTES SOURCES

Domestic wastes (gray water) originate from sinks, showers, laundry, food preparation areas, and galleys on the larger facilities. Domestic wastes also include solid materials such as paper, boxes, etc.

EPA compiled U.S. and international regulations governing the discharge of domestic wastes into ocean waters from ships and fixed or floating platforms. International waters are governed by MARPOL 73/78 (the International Convention for the Prevention of Pollution from Ships, 1973, as modified by the Protocol of 1978 relating thereto.) The Coast Guard implemented MARPOL 73/78 as part of its pollution regulations (33 CFR-Part 151) governing U.S. waters.

Disposal from drilling rigs are dealt with in Regulation 4 of Annex V of MARPOL. It states that:

(1) Fixed or floating platforms engaged in the exploration, exploitation, and associated offshore processing of sea-bed mineral resources, and all other ships alongside such platforms or within 500 meters of such platforms, are forbidden to dispose of any materials regulated by this Annex, except as permitted by paragraph (2) of this Regulation.

(2) The disposal into the sea of food wastes when passed through a comminutor or grinder from such fixed or floating drilling rigs located more than 12 nautical miles from land and all other ships when positioned as above. Such comminuted or ground food wastes shall be capable of passing through a screen with openings no greater than 25 mm.

Table X-20 summarizes the garbage discharge restrictions from fixed or floating platforms.

TABLE X-20

GARBAGE DISCHARGE RESTRICTIONS

Garbage Type	Fixed or Floating Platforms & Associated Vessels[2] (33 CFR 151.73)
Plastics - includes synthetic ropes and fishing nets and plastics bags.	Disposal prohibited (33 CFR 151.67)
Dunnage, lining and packing materials that float.	Disposal prohibited
Paper, rags, glass, metal bottles, crockery and similar refuse.	Disposal prohibited
Paper, rags, glass, etc. comminuted or ground.[1]	Disposal prohibited
Victual waste not comminuted or ground.	Disposal prohibited
Victual waste comminuted or ground.[1]	Disposal prohibited less than 12 miles from nearest land and in navigable waters of the U.S.
Mixed garbage types.[3]	See note 3.

(1) Comminuted or ground garbage must be able to pass through a screen with a mesh size no larger than 25 mm (1 inch) (33 CFR 151.75).
(2) Fixed or floating platforms and associated vessels include all fixed or floating platforms engaged in exploration, exploitation, or associated offshore processing of seabed mineral resources, and all ships within 500m of such platforms.
(3) When garbage is mixed with other harmful substances having different disposal requirements, the more stringent disposal restrictions shall apply.

5.2 Domestic Wastes Volume and Characteristics

The volume of domestic waste discharged has been estimated to range from 50 to 100 gallons per person per day, with a BOD of 0.2 pound per day per person.[39,40] It often is necessary to utilize macerators with domestic wastes to prevent the release of floating solids. Chlorination is not necessary since these wastes do not contain coliforms. Tables X-21 and X-22 summarize the volume and characteristics of domestic wastes.

TABLE X-21

TYPICAL UNTREATED COMBINED SANITARY AND DOMESTIC WASTES FROM OFFSHORE FACILITIES[41]

Number of Persons	Flow (gal/day)	BOD (mg/l)		Suspended Solids (mg/l)		
		Average	Range	Average	Range	Total Coliforms (x 10)
76	5,500	460	270-770	195	14-543	10-180
66	1,060	875		1,025	1,025	
67	1,875	460		620	620	
42	2,155	225		220	220	
10-40	2,900	920				

TABLE X-22

TYPICAL OFFSHORE SANITARY AND DOMESTIC WASTE CHARACTERISTICS[42]

Waste Type	Discharge Rate (m^3/cap/day)	Loading		Concentration		
		BOD (kg/cap/day)	S.S (kg/cap/day)	BOD (mg/l)	S.S (mg/l)	Residual Chlorine (mg/l)
Sanitary Waste (treated)	0.075	0.002	0.003	30	40	1.7
Domestic Waste (direct discharge)	0.110	0.022	0.016	195	140	0

5.3 DOMESTIC WASTES CONTROL AND TREATMENT TECHNOLOGIES

Because domestic wastes do not contain fecal coliform, no chlorination is required. Domestic wastes must only be ground up so as to comply with the NPDES permit prohibitions on discharges of floating solids. Maceration by comminutor should be sufficient treatment. Treatment such as macerators will guarantee that this discharge will not result in any floating solids. In addition, many existing NPDES permits prohibit discharges of foam (as no visible foam).

5.3.1 Additional Technologies

EPA is incorporating Annex V of the Convention to Prevent Pollution from Ships (MARPOL), Part 151 of Title 33 Code of Federal Regulations, and the Act to Prevent Pollution from Ships, 33, U.S.C. 1901 et seq., as the basis for BCT and NSPS limitations on domestic waste.

Under the Coast Guard Regulations, discharges of garbage, including plastics, from fixed and floating platforms engaged in the exploration, exploitation and associated offshore processing of seabed mineral resources are prohibited with one exception. Victual waste (not including plastics) may be discharged from fixed or floating platforms located beyond 12 nautical miles from the nearest land, if such waste is passed through a comminuter or grinder meeting the requirements of 33 CFR 151.75. Section 151.75 requires that the grinders or comminuters must be capable of processing garbage so that it passes through a screen with openings no greater than 25 millimeters (approximately one inch) in diameter.

6.0 SANITARY WASTES

6.1 SANITARY WASTES SOURCES, VOLUMES AND CHARACTERISTICS

The sanitary wastes from offshore oil and gas facilities are comprised of human body wastes from toilets and urinals. The volume and concentration of these wastes vary widely with time, occupancy, platform characteristics, and operational situation.

EPA compiled U.S. and international regulations governing the discharge of sanitary waste into ocean waters from manned ships and manned fixed or floating platforms. International waters are governed by MARPOL 73/78, Annex IV which deals specifically with the disposal of sewage from ships. The Federal Water Pollution Control Act (FWPCA) §312 (33 U.S.C. 1322) administered/implemented by U.S.EPA, provides the regulations and the standards to eliminate the discharge of untreated sewage from vessels into waters of the U.S. and the territorial seas. The U.S. Coast Guard has established regulations governing the design and construction of marine sanitation devices and procedures for certifying that marine sanitation devices meet the regulations of the FWPCA (33 CFR Part 159 and 40 CFR Part 140).

Combined sanitary and domestic waste discharge rates of 3,000 to 13,000 gallons per day have been reported.[21] Monthly average sanitary waste flow from Gulf Coast platforms was 35 gallons per day based on discharge monitoring reports.[12]

6.2 SANITARY WASTES CONTROL AND TREATMENT TECHNOLOGIES

There are two alternatives to handling of sanitary wastes from offshore facilities. The wastes can be treated at the offshore location, or they can be retained and transported to shore facilities for treatment. However, due to storage limitations on platforms, offshore facilities usually treat and discharge sanitary waste at the source. The treatment systems presently in use may be categorized as physical/chemical and biological.

Physical/chemical treatment may consist of evaporation-incineration, maceration-chlorination, and chemical addition. With the exception of maceration-chlorination, these types of units are often used to treat wastes on facilities with small numbers of men or which are intermittently manned. The incineration units may be either gas fired or electric. The electric units have been difficult to maintain because of saltwater corrosion and heating coil failure. The gas units are not subject to these problems, but create a potential source of ignition which could result in safety hazards. Some facilities have chemical toilets which require hauling of waste and create odor and maintenance problems. Macerators-chlorinators have not been used offshore but would be applicable to provide minimal treatment for small and intermittently manned facilities.

The most common biological system applied to offshore operations is aerobic digestion or extended aeration processes. These systems usually include a comminutor which grinds the solids into fine particles, an aeration tank with air diffusers, a gravity clarifier return sludge system, and a chlorination tank. These biological waste treatment systems have proven to be technically and economically feasible means of waste treatment at offshore facilities which have more than 10 occupants and are continuously manned.

BPT for sanitary wastes from offshore facilities continuously manned by 10 or more persons requires a residual chlorine content of 1 milligram per liter (and maintained as close to the limit as possible). Facilities continuously manned by fewer than 10 persons or intermittently manned by any number of persons are prohibited from discharging floating solids. These standards are based on end-of-pipe technology consisting of biological waste treatment systems (extended aeration). The system may include a comminutor, aeration tank, clarifier, return sludge system, and disinfection contact chamber. Studies of treatability, operational performance, and flow fluctuations are required prior to application of a specific treatment system to an individual facility. EPA has not identified any additional control beyond BPT appropriate for this waste stream.

7.0 MINOR DISCHARGES

The term "minor" discharges is used to describe all point sources originating from offshore oil and gas drilling and production operations, other than produced water, drilling fluids, drill cuttings, deck drainage, produced sand, well treatment, completion and workover fluids, and sanitary and domestic wastes. The following sections identify these discharges followed by a brief description.

7.1 BLOWOUT PREVENTER (BOP) FLUID

An oil (vegetable or mineral) or antifreeze solution (glycol) are used as hydraulic fluids in blowout preventer (BOP) stacks during drilling of a well. The blowout preventer may be located on the sea floor, and is designed to maintain the pressure in the well that cannot be controlled by the drilling mud. Small quantities of BOP fluid are discharged periodically to the sea floor during testing of the blowout preventer device.

7.2 DESALINATION UNIT DISCHARGE

This is the residual high-concentration brine discharged offshore from distillation or reverse osmosis units used for producing potable water and high quality process water. The concentrate is similar to sea water in chemical composition. However, as the name implies, anions and cations concentrations are higher. This waste is discharged directly to the sea as a separate waste stream.

7.3 FIRE CONTROL SYSTEM TEST WATER

Seawater, which may be treated with a biocide, is used as test water for the fire control system on the offshore platforms. This test water is discharged directly to the sea as a separate waste stream.

7.4 NON-CONTACT COOLING WATER

Non-contact, once-through water is used to cool crude oil, produced water, power generators, and various other pieces of machinery on offshore platforms. Biocides can be used to control biofouling in heat exchanger units. Non-contact cooling waters are kept separately and discharged directly to the sea.

7.5 BALLAST AND STORAGE DISPLACEMENT WATER

Two types of ballast water are found in offshore producing areas: tanker and platform ballast. Tanker ballast water can be either sea water or fresh water from the area where ballast was pumped into the vessel. It may be contaminated with crude oil (or possibly some other cargo such as fuel oil), if the vessel is not equipped for segregated cargo and does not have segregated ballast tanks.

Unlike tank ballast water, which may be from multiple sources and may contain added contaminants, platform stabilization (ballast) water is taken on from the waters adjacent to the platform and will, at worst, be contaminated with stored crude oil and platform oily slop water. Newly designed and constructed floating storage platforms use permanent ballast tanks that become contaminated with oil only in emergency situations when excess ballast must be taken on. Oily water can be treated through the oil/water separation process prior to discharge.

Storage displacement water from floating or semi-submersible offshore crude oil structures is composed mainly of seawater. Much of this volume usually can be discharged directly without treatment, since little mixing occurs with the oil floating on top of the water. The water which comes in contact with the oil can receive a small amount of dissolved aromatic constituents through molecular diffusion at the oil-water interface. Paraffinic compounds have low solubilities in water and will not migrate into water solution to any appreciable degree. The interface water is usually treated through the oil/water separator system before discharge.

7.6 BILGE WATER

Bilge water is a minor waste for floating platforms. Bilge water is seawater that becomes contaminated with oil and grease and with solids such as rust, when it collects at low points in the bilges. This bilge water is usually directed to the oil/water separator system used for the treatment of ballast or produced water, or is discharged intermittently.

7.7 BOILER BLOWDOWN

Purges from boilers circulation waters necessary to minimize solids build-up are intermittently discharged to the sea.

7.8 TEST FLUIDS

Test fluids are discharges that would occur if hydrocarbons are located during exploratory drilling and tested for formation pressure and content.

7.9 DIATOMACEOUS EARTH FILTER MEDIA

Diatomaceous earth filter media are used to filter seawater or other authorized completion fluids and then washed from the filtration unit.

7.10 BULK TRANSFER OPERATIONS

Bulk materials such as barite or cement may be discharged during transfer operations.

7.11 PAINTING OPERATIONS

Discharges of sandblast sand, paint chips, and paint spray may occur during sandblasting and painting operations.

7.12 UNCONTAMINATED FRESHWATER

Uncontaminated freshwater discharges come from wastes such as air conditioning condensate or potable water during transfer or washing operations.

7.13 WATER FLOODING DISCHARGES

Oil fields that have been produced to depletion and have become economically marginal may be restored to production, with recoverable reserves substantially increased, by secondary recovery methods. The most widely used secondary recovery method is water flooding. A grid pattern of wells is established, which usually requires downhole repairs of old wells or drilling of new wells. By injecting water into the reservoir at high rates, a front or wall of water moves horizontally from the injection wells toward the producing wells, building up the reservoir pressure and sweeping oil in a flood pattern.

Water flooding can substantially improve oil recovery from reservoirs that have little or no remaining reservoir pressure. Treated seawater typically is used offshore for injection purposes. Treatment consists of filtration to remove solids that would plug the formation, and deration. Dissolved oxygen is removed to protect the injection pipeline system from corrosion. A variety of chemicals can be added to water flooding systems such as flocculants, scale inhibitors, and oxygen scavengers. Biocides are also used to prevent the growth of anaerobic sulfate-reducing bacteria, which can produce corrosive hydrogen sulfide in the injection system. Discharges to the marine environment from water flooding operations will include excess injection water and backwash from filtering systems.

7.14 LABORATORY WASTES

Laboratory wastes contain material used for sample analysis and the material being analyzed. The volume of this waste stream is relatively small and is not expected to pose significant environmental problems. Freon may be present in laboratory waste. Because freon is highly volatile, it will not remain in aqueous state for very long. The Agency is discouraging the discharge of chlorofluorocarbon to air or water media.

7.15 Minor Wastes Volumes and Characteristics

Information concerning the characteristics, discharge volumes, and the frequency of discharge of these minor waste streams is limited. Table X-23 provides a range of discharge volumes for the minor waste streams.[26] Data concerning the characteristics and volumes of test fluids, diatomaceous earth filter media, bulk transfer operations, and painting operations are not available.

TABLE X-23

MINOR WASTE DISCHARGE VOLUMES[26]

Waste	Discharge Volume
BOP fluid	67 - 314 bbl/day
Boiler blowdown	0 - 5 bbl/day
Desalination waste	typically <238 bbl/day
Fire system test water	24 bbl/test
Noncontact cooling water	7 - 124,000 bbl/day
Uncontaminated ballast/bilge water	70 - 620 bbl/day
Water flooding	up to 4,030 lb solids/month
Test fluids	Unknown
Diatomaceous earth filter media	Unknown
Bulk transfer operations	Unknown
Painting operations	Unknown
Uncontaminated fresh water	Unknown

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SECTION XI

COST AND POLLUTANT LOADING DETERMINATION—DRILLING FLUIDS AND DRILL CUTTINGS

1.0 INTRODUCTION

This section presents costs and pollutant reductions for the final set of proposed regulatory options for drilling fluids and drill cuttings. Compliance costs were developed for each treatment/control option for the Gulf of Mexico and offshore of California and Alaska. Compliance costs were not developed for the Florida and North Atlantic OCS Planning areas due to presidential moratoria on oil and gas leasing and development in these areas. Although not specifically developed, compliance costs in these areas are considered to be comparable to the compliance costs incurred in the California region.

2.0 OVERVIEW OF METHODOLOGY

To evaluate the compliance costs and pollutant removals associated with regulatory options considered in this rulemaking the following information was used:

- Number of offshore wells that will be drilled in the 15-year period following promulgation of this rule in three geographic regions: Gulf of Mexico, California, and Alaska.
- Typical "model" wells to predict volumes of drilling wastes.
- Characteristics of the drilling waste including additives, volumes and composition.
- Drilling wastes monitoring, transportation, and disposal costs.

The data were entered into computer models designed to predict industry-wide compliance costs and pollutant removals for the various regulatory options. No distinction was made between BAT and NSPS options, because there are no, or minimal, differences in the compliance costs for existing and new sources of drilling waste. Compliance costs were computed for the three geographic regions where offshore drilling was projected (Gulf of Mexico, California, and Alaska). In characterizing the offshore drilling industry, EPA developed two drilling activity scenarios that project the number of wells drilled for the 15-year period following promulgation of this rule. The two scenarios of future drilling activity are: the "restricted" or "constrained" scenario and the "unrestricted" or "unconstrained" scenario. The constrained scenario accounts for less drilling activity due to the presidential and congressional moratoria on offshore oil and gas leasing and development. See Section III.2.2 for a discussion on the presidential and congressional moratoria. The unconstrained scenario takes into account potential drilling activities in the areas that have been excluded from leasing and development by the presidential and congressional moratoria, in particular the Atlantic Ocean OCS planning areas and offshore California OCS planning areas. Because EPA expects that existing moratoria will remain in place, and based on a review of the current offshore drilling activity, EPA considered the constrained scenario a more accurate projection of future activity and thus, the constrained scenario is the basis for determining compliance costs and pollutant removals for this final rule.

2.1 CURRENT NPDES PERMIT LIMITATIONS

Discharges of drilling fluids and drill cuttings from offshore drilling projects in the Gulf of Mexico, California, and Alaska are regulated by both individual and general NPDES permits. The NPDES permits include additional limitations on drilling fluid discharges that are more stringent than the BPT limitations that were promulgated in 1979. The BPT limitations on drilling fluids prohibit the discharge of oil-based muds and the discharge of free oil. The additional constraints imposed by the general NPDES permits issued for offshore drilling operations in the Gulf of Mexico (EPA Region VI), California (EPA Region IX), and Alaska (EPA Region X) represent limitations established by regional permit writers based on both BPT and best professional judgment (BPJ) of BAT-level technology. BPJ requirements are thus considered to represent current discharge and waste handling practices for the offshore drilling industry. BPJ limitations represent the pollutant removals and the costs that are incurred by drilling operations under the NPDES permit limitations. These limitations, as they are currently enforced, are summarized in Table III-1 for the three geographic areas. BPJ restrictions for drilling fluids were considered to represent the baseline requirements from which incremental costs and pollutant removals for this rule were determined for drilling fluids. Since the NPDES permits do not place any additional limitations on drill cuttings, BPT limitations on the discharge of free oil represent current practices and are used as the baseline requirements from which incremental costs and pollutant removals for this rule were determined for drill cuttings.

3.0 BASIS FOR ANALYSIS AND ASSUMPTIONS

3.1 DRILLING ACTIVITY

The Agency developed projections of the number of wells that will be drilled annually for the 15 year period following promulgation of this rule based on EPA assessments of Minerals Management Service (MMS) hydrocarbon production projections for federal waters, and review of state offshore drilling activity. A detailed discussion of these projections is presented in the Economic Impact Analysis. Table XI-1 presents the constrained scenario of future drilling activity.

TABLE XI-1

NUMBER OF WELLS DRILLED PER YEAR
(Based on Restricted Profile)

	Distance from Shore (nautical miles)					Total
	0-3	3-4	4-6	6-8	>8	
Gulf of Mexico	60	12	7	57	579	715
California	0	0	23	6	3	32
Alaska	9	0	0	0	3	12
Total	69	12	30	63	585	759

The constrained scenario projects that an average of 759 new wells will be drilled annually over the next 15 years. As can be seen in Table XI-1, approximately 9 percent of all wells are projected to be drilled within 3 miles from shore, approximately 11 percent of all wells are projected to be drilled within 4 miles from shore, approximately 15 percent of all wells are projected to be drilled within 6 miles from shore, and approximately 23 percent of all wells are projected to be drilled within 8 miles from shore.

3.2 DRILLING WASTE VOLUMES

The volumes of drill waste (drilling fluid and drill cuttings) generated per well were calculated based on muds and cuttings generation rates and on well depth. The methodology used in determining these two components and in determining the total drill waste generated per well are presented in the following paragraphs.

The methodology used for estimating the volume of drilling fluid and drill cuttings discharged is based on the volumes generated from exploratory wells drilled in the Gulf of Mexico in 1981. Data of muds and cuttings generation rates for a 10,000 foot well and an 18,000 foot well is presented in the report prepared by the OOC entitled *Alternative Disposal Methods for Muds and Cuttings in the Gulf of Mexico and Georges Bank.*[1] For the two wells drilled, the report provides hole size diameter per depth intervals, muds and cuttings discharge volumes per depth intervals, and total volumes of muds and cuttings discharged. Table VII-1 in Section VII-2 presents these data. These data were used to determine the relationship between the theoretical hole volume and the volume of muds and cuttings discharged. EPA estimated the cuttings generation rate for both the shallow and deep wells to be equal to one theoretical hole volume. Based on the findings of the OOC report for drilling fluids, EPA estimated the shallow well generation volumes to be equal to 4.7 times the theoretical hole volume and the deep well generation volumes equal to 3.9 times the theoretical hole volume.

The estimated cuttings and fluids generation rates were then applied to estimated or "model" well volumes to estimate the industry-wide volumes of drill cuttings and drilling fluids generated per well. EPA developed model wells for each region based on the average depth of wells drilled in that region. The average well depth was determined for each region based on five years (1985 through 1989) of industry drilling data.[2] The average well depth value (referred to as the "shallow well" in this discussion) represents the ratio of total footage drilled to the total number of wells drilled for the period. The average well depths were found to be drilled approximately 10,000 linear feet. Since deep wells require larger diameter boreholes (thus generating a greater volume of drill waste than a smaller diameter borehole over a particular depth interval), the percentage of wells drilled in the five-year period which exceed the depth of the average well for each region was determined (referred to as the "deep well").

Table XI-2 presents the well depth, mud volume, and cuttings volume estimated for the shallow and deep wells drilled in the Gulf of Mexico, California, and Alaska.

TABLE XI-2

MODEL WELL CHARACTERISTICS[2]

	Model Well	Gulf of Mexico	California	Alaska
Shallow Well	Well Depth Mud Volume Cuttings Vol.	10,559 feet 6,938 bbl/well 1,475 bbl/well	7,607 feet 5,939 bbl/well 1,242 bbl/well	10,633 feet 6,963 bbl/well 1,480 bbl/well
Deep Well	Well Depth Mud Volume Cuttings Vol.	13,037 feet 9,752 bbl/well 2,458 bbl/well	10,082 feet 6,777 bbl/well 1,437 bbl/well	12,354 feet 9,458 bbl/well 2,413 bbl/well
	Percentage of Wells Greater Than Average Well Depth	49%	42%	59%

3.3 Drilling Fluid Characteristics

EPA selected three types of drilling fluids to represent the most common types of drilling fluids used in the offshore industry. Table XI-3 presents the characteristics of these muds. For the purposes of determining the pollutant loadings and the barite usage, EPA selected a single density mud which would represent the average mud density over the total drilling project, from the initial seawater/spud mud to the weighted mud used towards the final well depth. Based on a review of discharge monitoring reports from the Gulf of Mexico and communications with the industry, EPA selected an 11 pound per gallon mud to have the average characteristics (density) of the mud system used over the entire drilling project.[3]

TABLE XI-3

DRILLING FLUIDS COMPOSITION[3]

Water-Based Mud Without Oil Additive (0-10,000 ft)	
Component	**Composition (lb/bbl)**
Seawater	303
Bentonite	20
Barite	98
Drill Solids	40
Total:	461
Estimated TSS	153
Dry Mud	158
Water-Based Mud With Oil Additive (0-14,000 ft)	
Component	**Composition (lb/bbl)**
Seawater	294
Bentonite	20
Barite	98
Drill Solids	40
Mineral Oil	9 (3% by volume)
Total:	461
Estimated TSS	153
Dry Mud	167
Oil-Based Mud (10,000-14,000 ft)	
Component	**Composition (lb/bbl)**
Seawater	124
Bentonite	20
Barite	98
Drill Solids	40
Mineral Oil	179 (60% by volume)
Total:	461
Estimated TSS	153
Dry Mud	337

3.4 DRILL CUTTINGS CHARACTERISTICS

Drill cuttings were assumed to have a density of 543 pounds per barrel and contain 5 percent drilling fluid.[4] For the purpose of the pollutant loading analysis for this rule, the only source of hydrocarbons or metals in the drill cuttings is the residual drilling fluids.

3.5 LUBRICITY

In 1983 and 1984, the industry surveyed 11 major drilling contractors operating in the Gulf of Mexico to characterize: the use of hydrocarbons as lubricity agents in water-based muds and the usage of diesel and mineral oil as spotting fluids.

Data from the 1984 survey indicate that 12 percent of all wells drilled using a water-based mud used hydrocarbons as a lubricity agent. Of these, approximately 67 percent used mineral oil as the lubricity agent and 33 percent used diesel oil.[5] This information was used to quantify the amounts and identify the types of oil currently being used in the offshore drilling industry.

3.6 STUCK PIPE INCIDENTS

The OOC Spotting Fluid Survey characterized stuck pipe incidents and the type of pills used to free stuck pipes. See Section V.2.3 for a discussion about the survey. Data from the survey indicate that 22.1 percent of all wells drilled with a water-based mud experienced a stuck pipe where a pill was needed to free the drill string.[6] This information was used to quantify the volumes of oil used in spotting fluids.

3.7 MINERAL AND DIESEL OIL USAGE

The substitution of mineral oil for diesel oil is a means for compliance with the BPT and BPJ limitations. Prior to the promulgation of BPT, operators primarily used diesel oil as a lubricity agent or for freeing stuck pipe. However, since the promulgation of the BPT prohibitions on the discharges of free oil, the usage of diesel oil has drastically reduced to the point where currently diesel oil is seldom used. Table XI-4 presents the results from two industry surveys characterizing the usage of diesel and mineral oil as lubricity agents and as spotting fluids. The API Hydrocarbon Usage Survey,[5] "1984 Survey," examined diesel/mineral oil usage in spotting fluids in 1983 and 1984; and examined diesel/mineral oil usage as a lubricity agent in 1984. The OOC Spotting Fluid Survey,[6] "1986 Survey," compiled diesel/mineral oil usage in spotting fluids for the years 1983 through 1986.

TABLE XI-4

MINERAL AND DIESEL OIL USAGE

STUDY	Lubricity Agent		Spotting Fluid	
	Diesel Oil	Mineral Oil	Diesel Oil	Mineral Oil
1984[5]	33%	67%	79%	21%
1986[6]	Not Surveyed	Not Surveyed	59%	41%

For the purpose of estimating the impact of BAT and NSPS limitations to the industry, EPA assumed the post-BPT diesel usage rate to be equal to zero percent and that all facilities currently use only mineral oil for lubricity agents and spotting fluids. Diesel usage for those operators participating in the Diesel Pill Monitoring Program (DPMP) has not been factored into the post-BPT diesel usage estimates since, the DPMP was a limited NPDES permit provision for a special test case. Table XI-5 presents the organic constituents in the mineral oil used to calculate the pollutant loadings for this rulemaking.

TABLE XI-5

ORGANIC CONSTITUENTS IN MINERAL OIL TYPE A[7]

Organic Constituent	Concentration (mg/ml)
Benzene	ND
Napthalene	0.05
Fluorene	ND
Phenanthrene	ND
Phenol	ND
Non-Conventional Organics	30.51

Notes:
(1) ND = Not Detected
(2) Non-conventional organics include 30.0 mg/ml alkylated benzenes (include C_1 through C_6 alkyl homologues), 0.28 mg/ml alkylated naphthalenes and 0.23 mg/ml total biphenyls (C_1 through C_5 alkyl homologues).

3.8 BARITE CHARACTERISTICS

Barite is the primary source of metals (cadmium, mercury, and other priority pollutants of concern) in drilling fluids. The characteristics of the raw barite used will determine the concentrations of metals in the drilling fluid. The concentrations of cadmium and mercury are directly related to the concentrations of other priority pollutants of concern in barite.[8] Current NPDES permits in Regions IX and X have limitations on the concentrations of cadmium and mercury in the raw (or stock) barite. On November 19, 1992 (57 *FR* 54642) EPA Region VI issued an NPDES general permit for the central and western Gulf of Mexico OCS. This permit places limitations on mercury and cadmium in the stock barite. Stock barite that meets metals limitations is referred to as "clean" barite. For the purposes of calculating the BPJ baseline metals concentrations in drilling fluids, the metals concentrations of clean barite was used for California and Alaska and dirty barite was used for the Gulf of Mexico. Dirty barite was used to develop the baseline for the Gulf of Mexico because the NPDES general permits did not include barite limitations at the time of the analysis. The difference in the characteristics of the drilling fluids between the Gulf of Mexico and California/Alaska is demonstrated in the API/USEPA Metals Database. A statistical analysis of metals concentrations in spent drilling fluids shows higher concentrations of cadmium and mercury in drilling fluids from the Gulf of Mexico than from offshore Alaska and California.[8]

The mean metals concentrations for "clean" and "dirty" barite are presented in Table XI-6. The metals concentrations represent averages of untransformed data from two datasets: *The 15 Rig Study* from the Gulf of Mexico and *Region 10 Discharge Monitoring Report Data*.[8] The metals concentrations of drilling fluids from the Gulf of Mexico are considered to represent those of dirty barite, and the metals concentrations from Region 10 are considered to represent those of clean barite. Where no concentration data were given for an analyte in the Region 10 data, the concentration of the analyte from the Gulf of Mexico dataset was incorporated. The barium concentrations reported in Table XI-6 are calculated from the total pounds of barite in the drilling fluid. The amount of barite per barrel of drilling fluid is 98 pounds, as presented in Table XI-3. The barite was assumed to be pure barium sulfate (100% $BaSO_4$) and the barium sulfate was assumed to contain 58.8 percent (by weight) barium.

For the purposes of calculating the pollutant loadings for the BAT and NSPS options, clean barite was substituted for dirty barite for drilling operations in the Gulf of Mexico. Clean barite was not substituted for dirty barite where the discharges of drilling fluids are prohibited (projects using oil based-muds and within zero discharge areas) or in areas where clean barite is required by NPDES discharge permits (offshore California and Alaska). For those drilling operations requiring substitution of clean barite for dirty barite (Gulf of Mexico) a substitution cost of $13.50 per ton of barite (1986$) was incurred.[9]

In calculating the BCT pollutant loadings and costs, clean barite substitution was not used because the metals limitations are not considered and/or accounted for as conventional pollutants.

TABLE XI-6

METALS CONCENTRATIONS IN BARITE[8]

Metal	"Dirty" Barite Concentration (mg/kg)	"Clean" Barite Concentration (mg/kg)
Cadmium	2.3	1.1
Mercury	0.7	0.1
Aluminum	9,069.9	9,069.9
Antimony	5.7	5.7
Arsenic	12.0	7.1
Barium[(3)]	359,747.0	359,747.0
Beryllium	0.7	0.7
Chromium	561.4	240.0
Copper	39.9	18.7
Iron	15,344.3	15,344.3
Lead	66.7	35.1
Nickel	13.5	13.5
Selenium	1.1	1.1
Silver	0.7	0.7
Thallium	1.2	1.2
Tin	14.6	14.6
Titanium	87.5	87.5
Zinc	200.5	200.5

3.9 ONSHORE DISPOSAL VOLUMES/TOXICITY TEST FAILURE RATES

The amount of drill waste brought to shore for disposal is a function of the compliance failure rates. The likelihood of drilling wastes from the model well failing either the static sheen test or the toxicity limit was estimated based on data and information compiled by the industry. EPA assumed that all oil-based drilling fluids would fail the sheen test. According to industry sources, when oil is added to water-based muds to increase the lubrication properties of the mud, there is an average 56 percent probability that the resultant mud will fail the toxicity limit of 30,000 ppm.[10] Additionally, EPA previously estimated the likelihood of drilling wastes from a "model well" failing the proposed static sheen test and toxicity limit. Because no public comments addressing these failure rates have been submitted, they are still assumed representative of the industry. Table XI-7 shows the failure rates, as they were presented in the March 13, 1991 proposal (56 *FR* 10664), and as they have been used to predict volumes of muds and cuttings requiring onshore disposal.

TABLE XI-7

TOXICITY/STATIC SHEEN TEST FAILURE RATES[10]

Drill Waste	Fail Sheen(%)	Fail Toxicity(%)
Water-based mud; no oil	0	1
Water-based mud; with spot	0	33
Water-based mud; with lubricity	0	33
Water-based mud; with spot and lubricity	0	56
Oil-based mud	100	N/A
Cuttings - water-based mud	0	N/A
Cuttings - oil-based mud	100	N/A

The assumption was made that each drilling operation will take a minimum of two mud samples to satisfy the requirements of the NPDES permit. Each toxicity test was estimated to cost approximately $1,000. The cost of the visual sheen test is negligible and EPA considered the cost of the static sheen test is negligible in comparison with the cost of the bioassay test.

Under the current BPJ limitations and based on failure rates of the toxicity test, 12 percent of all drilling fluids are disposed of onshore due to noncompliance and 2 percent of all drill cuttings are disposed of onshore due to noncompliance (see Section XI-7).

3.10 Onshore Disposal Costs of Drilling Wastes

Drilling wastes disposal costs include: the gate costs charged by the onshore disposal facility, the handling cost, the transportation cost, the container rental cost, the costs associated with rig downtime (where applicable), and the capital cost incurred to retrofit a typical rig for additional storage space (where applicable).[11]

Three estimates of total onshore disposal cost were developed: the first two assume costs for disposal under certain wave height conditions using a dedicated boat to receive waste; the third assumes retrofitting the platform to provide additional storage capacity between shipments. EPA assumed that the majority of the existing platforms and drilling rigs would be retrofitted and that new structures would be designed to have sufficient storage space. Because retrofitting existing platforms is the easiest and safest method to provide additional storage space and minimizing drilling downtime is more economical for the industry, EPA predicted that 80 percent of the existing platforms and/or rigs will be modified for larger storage capacity. EPA assumed that 20 percent of the existing platforms and/or rigs will not be retrofitted because of structural limitations. Some of the older rigs have limited space and are already at maximum loading (weight) conditions and retrofitting would be technically infeasible. The capital costs associated with retrofitting an offshore rig with additional storage capacity (approximately 500 barrels) and deck space (approximately 500 ft^2) to accommodate storage of muds and cuttings are $19,000 for the installation of a drilling mud storage tank and $125,000 for additional deck space (1986$). The additional deck space would accommodate four full 25 barrel cuttings containers and a 500 barrel mud storage tank.

An important factor in developing total disposal costs for muds and cuttings from platforms where retrofitting is not a viable solution is the downtime cost incurred as a result of adverse weather conditions. Depending on the available storage space and drilling waste generation rate, the inability to unload muds and cuttings when generated could possibly result in a temporary shutdown of the drilling operation. Based on significant wave height data supplied by the National Oceanic and Atmospheric Administration (NOAA), downtime costs were estimated for maximum significant permissible wave heights of 6 and 10 feet. These wave heights were assumed to be the maximum allowable wave conditions for safe loading operations. For the costing scenario with no retrofit of storage capacity, EPA projected that 10 percent of the wells would incur downtime costs under 6 feet and 10 feet wave conditions, respectively.

Table XI-8 presents the weighted average onshore disposal costs for muds and cuttings. The costs include costs for retrofitting 80 percent of the drilling rigs and platforms and downtime costs for the 20 percent of the drilling projects that could not increase the storage capacity due structural limitations.

TABLE XI-8

DRILL WASTE ONSHORE DISPOSAL COSTS (1986 $/BARREL)

	Drilling Fluids	Drill Cuttings
Gulf of Mexico	21.29	23.53
Pacific	23.50	28.52
Alaska	26.99	29.26

3.11 CONTAMINANT REMOVAL

In determining pollutant removals, specific pollutants were selected for evaluation based on their consistently significant presence in drilling wastes from offshore oil and gas operations. Reductions of pollutants being discharged to the surface waters are a result of: the no free oil limitation, the metals limitation, and any zero discharge requirements. Removals are considered direct or incidental. The direct removals are those pollutant removals which are targeted by the limitation. Incidental removals are those pollutant removals that are a result of the implementation of the limitation but not specifically targeted by the limitation. The direct removals are organic pollutants associated with diesel oil (and present in mineral oil), total suspended solids, oil and grease, cadmium, and mercury. Table XI-9 presents the direct and incidental pollutants as they pertain to this rulemaking.

TABLE XI-9

DIRECT AND INDIRECT POLLUTANTS AS DEFINED BY THIS RULEMAKING

Direct Discharges		Incidental Discharges	
Priority	**Conventional**	**Priority**	**Other**
Benzene	TSS	Antimony	Aluminum
Naphthalene	Oil	Arsenic	Barium
Fluorene		Beryllium	Iron
Phenanthrene		Chromium	Tin
Phenol		Copper	Titanium
Cadmium		Lead	Non-conventional
Mercury		Nickel	Organics
		Selenium	
		Silver	
		Thallium	
		Zinc	

4.0 BCT OPTIONS CONSIDERED

The following options for drilling fluids and drill cuttings were evaluated as BCT control and treatment options for the final rule:

- **Option 1:** "3 Mile Gulf/California" - All regions except offshore Alaska would be prohibited from discharging drilling fluids and drill cuttings from all wells located within three miles from shore. All wells located beyond three miles from shore as well as all wells being drilled offshore Alaska, would be permitted to discharge drilling fluids and drill cuttings that are in compliance with the no discharge of free oil limitation as determined by the static sheen test.

- **Option 2**: "8 Mile Gulf/3 Mile California" - Zero discharge for all wells in the Gulf of Mexico located within eight miles from shore and zero discharge for all wells offshore California located within three miles from shore. All wells located beyond eight miles from shore in the Gulf of Mexico, beyond three miles from shore in California, and all wells drilled offshore Alaska are permitted to discharge drilling fluids and drill cuttings that are in compliance with the no discharge of free oil limitation as determined by the static sheen test.

- **Option 3**: "Zero Discharge Gulf/California" - Zero discharge for all wells located in the Gulf of Mexico and offshore California. All wells being drilled offshore Alaska permitted to discharge drilling fluids and drill cuttings that are in compliance with the no discharge of free oil limitation as determined by the static sheen test.

- **Option 4**: "4 Mile Gulf/California" - All regions except offshore Alaska would be prohibited from discharging drilling fluids and drill cuttings from all wells located within four miles from shore. All wells located beyond four miles from shore as well as all wells being drilled offshore Alaska, would be permitted to discharge drilling fluids and drill cuttings that are in compliance with the no discharge of free oil limitation as determined by the static sheen test.

- **Option 5**: "6 Mile Gulf/California" - All regions except offshore Alaska would be prohibited from discharging drilling fluids and drill cuttings from all wells located within six miles from shore. All wells located beyond six miles from shore as well as all wells being drilled offshore Alaska, would be permitted to discharge drilling fluids and drill cuttings that are in compliance with the no discharge of free oil limitation as determined by the static sheen test.

- **Option 6**: "8 Mile Gulf/California" - All regions except offshore Alaska would be prohibited from discharging drilling fluids and drill cuttings from all wells located within eight miles from shore. All wells located beyond eight miles from shore as well as all wells being drilled offshore Alaska, would be permitted to discharge drilling fluids and drill cuttings that are in compliance with the no discharge of free oil limitation as determined by the static sheen test.

In referring to the options considered for control of drilling fluids and drill cuttings, the Gulf of Mexico, California and Alaska regions are used in the option descriptions and accompanying discussion. Use of these regions in this manner is only a "shorthand" way of referring to regulatory packages and does not exclude other geographic areas from coverage under this rule. For the BCT, BAT and NSPS limitations under this rule, all offshore areas other than offshore California and Alaska, i.e. offshore Florida, Oregon, Washington, and the Atlantic Coast, would be required to comply with the limitations established for the Gulf of Mexico.

4.1 BAT AND NSPS OPTIONS

Six options were considered for BAT and NSPS control and treatment of drilling fluids and drill cuttings for the final rule. These options set BAT and NSPS limitations identical to BCT limits with respect to areas of zero discharge for drilling fluids and drill cuttings. BAT and NSPS limits differ from BCT limits in that they place additional limitations on the discharge of priority and non-conventional pollutants for areas (greater distances from shore) in which discharges are permissible. These limitations are being placed on the drill cuttings as well as the drill fluids because the data show that drilling fluid adheres to cuttings and is discharged along with the drill cuttings. The same pollutants found in drilling fluids are thus found on the drill cuttings.

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

The purpose of the toxicity limitation is to encourage the use of water-based or other low toxicity drilling fluids and the use of low-toxicity drilling fluid additives. 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. These standards are not expected to have any adverse non-water quality environmental impacts. 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 reuse or land disposal.

The toxicity limitation would apply to any periodic blowdown 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. For example, 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, although the operation 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.

Diesel oil and free oil serve as "indicators" of toxic pollutants, and thus these discharges are prohibited by this rule. 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 limitation. Diesel oil will be regulated as a toxic pollutant because it contains such toxic organic pollutants as benzene, toluene, ethylbenzene, naphthalene, and phenanthrene. The method of compliance with this prohibition is to: (1) use mineral oil instead of diesel oil for lubricity and spotting purposes; or (2) transport to shore for recovery of the oil, reconditioning of the drilling fluid for reuse, and land disposal of the drill cuttings. EPA believes that in most cases substitution of mineral oil will be the method of compliance with the diesel oil discharge prohibition. Mineral oil is a less toxic alternative to diesel oil and is available to serve the same operational requirements. Low toxicity mineral oils and other drilling fluid systems, such as polyolefin, vegetable oil and synthetic hydrocarbon-based fluids are available as substitutes for diesel oil and continue to be developed for use in drilling systems.

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

Cadmium and mercury will be regulated at a level of 3 and 1 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 will be regulated to control the metals content of the barite component of any drilling fluid discharges. Compliance with this requirement will involve use of barite from sources that either do not contain these metals or contain the metals at levels below the limitation.

5.0 OPTION EVALUATIONS

An analysis of each regulatory option was conducted to determine:

- Cost incurred by industry to comply with the regulation.
- Volume and percent of drilling waste requiring onshore disposal.
- Reduction of pollutants discharged to surface waters.
- Number of "well-equivalents" affected by the regulation. A "well-equivalent" is an artificial measurement which is equal to the volume of one model well.

To develop the compliance costs and pollutant removals for each option several assumptions were made about the drilling operation. Several of these assumptions were presented in Section XI-3, but they are presented here in tabular form for clarity. The assumptions used to characterize the industry for a typical drilling scenario, diesel and mineral oil usage, clean and dirty barite compositions, and pollutant concentrations in drilling fluids and cuttings are presented in Table XI-10.

The remainder of this section discusses the calculation of costs and pollutant loadings for each regulatory option considered. Tables XI-15 through XI-18, located in Section XI.7, present the results of all pertinent calculations.

TABLE XI-10

INDUSTRY-WIDE DRILLING ASSUMPTIONS

1) Typical Drilling Scenario	
a)	88% of all wells use water-based mud without lubricity for the first 10,000 ft.[5]
b)	12% of all wells use water-based mud with mineral oil as a lubricity agent for the first 10,000 ft.[5]
c)	15% of all deep wells use oil-based mud for depths greater than 10,000 ft.[12]
d)	85% of all deep wells use water-based mud with mineral oil lubricity for depths greater than 10,000 ft.[12]
e)	22% of all wells experience stuck pipe between 8,000 ft. and 10,000 ft or the average well depth.[6] Mineral oil pills are used to free the pipe.
f)	22% of all deep wells experience stuck pipe between 12,000 ft. and the final well depth.[6] Mineral oil is used to free the pipe.
g)	35 days are needed to drill a model well. Of this, 20 days are spent drilling.
h)	5% of mud volume is retained on cuttings.[4]
2) Diesel/Mineral Oil Usage	
a)	Diesel oil is not currently used in drilling operations either for lubricity or as a pill.
b)	Mineral oil for lubricity equals 3% of mud volume.
c)	Mineral oil for pill equals 100 bbl: 50% is retained in mud and 50% is retained on cuttings.
d)	Oil-based muds contain 60% by volume mineral oil.
e)	Cost to substitute mineral oil for diesel oil is $2/gallon.[13]
3) Clean/Dirty Barite	
a)	Mercury and cadmium dry weight concentrations in drilling fluids where "dirty barite" was used have been estimated from industry data to be 0.7 and 2.3 mg/kg on dry weight basis, respectively.[8]
b)	Mercury and cadmium dry weight concentrations in drilling fluids where "clean barite" was used, have been estimated from industry data to be 0.1 and 1.1 mg/kg, respectively.[8]
c)	All facilities in California and Alaska were using "clean" barite in order to comply with their respective NPDES permits until the most recently issued permit for Region VI OCS general permit for the central and western Gulf of Mexico was issued. Drilling operations in the Gulf of Mexico use "dirty" barite because this permit was so recently promulgated, these limits were not taken into account in establishing the baseline.
d)	Cost to substitute clean barite in the Gulf of Mexico is $13.50 per ton of barite.[9]

5.1 BPT AND BPJ BASELINE

To determine the incremental compliance costs and pollutant removals for the BCT, BAT, and NSPS options, the "baseline" compliance costs and pollutants for the BPT and BPJ limitations for drilling fluids and drill cuttings are necessary.

5.1.1 BPT Baseline: Drilling Fluids

BPT limitations on drilling fluids prohibit the discharge of oil-based muds and free oil, as determined by the visual sheen test. The costs incurred by industry to comply with BPT consist of; (1) transportation costs and onshore disposal costs for all oil based muds and (2) a product substitution cost to replace diesel oil with mineral oil to comply with the BPT no discharge of free oil limitation.

The onshore disposal costs are based on the fact that fifteen percent of all deep wells use oil-based muds for depths greater then 10,000 feet. The computer model determined the volumes of oil-based muds generated from deep wells over 10,000 feet and the onshore disposal costs presented in Section XI.3.10 were used to calculate the costs incurred due to the zero discharge limitation on oil-based muds. The pollutant reductions associated with this limitation are based on the volumes of oil (organic pollutants) and TSS transported to shore for treatment and/or disposal. The pollutant reductions were calculated using the total volume (weight) of drilling fluid transported to shore and the characteristics (oil content and TSS concentration) of the drilling fluid.

Product substitution costs are based on the fact that to comply with the BPT no discharge of free oil limitation, operators will substitute mineral oil for diesel oil where oil is used as a lubricity agent in water-based muds and as a spotting fluid for freeing stuck pipe. EPA determined the costs of substituting mineral oil for diesel to be $2 per barrel.[13] This substitution cost is based on the increase in the purchase cost of the mineral oil over diesel oil plus the cost to provide and maintain additional storage facilities for the mineral oil on the platform. The total costs incurred due to product substitution are calculated based on the total oil used for lubricity and spotting fluids and the cost per gallon of substituting mineral oil for diesel oil. There are no calculable pollutant removals due to product substitution.

5.1.2 BPT Baseline: Drill Cuttings

BPT limitations on drill cuttings prohibit the discharge of free oil, which indirectly prohibits the discharge of cuttings from oil-based muds. The costs incurred by industry to comply with BPT consist of transportation costs and onshore disposal costs for cuttings from oil based muds.

The onshore disposal costs are based on the fact that fifteen percent of all deep wells use oil-based muds for depths greater then 10,000 feet. The computer model determined the volumes of cuttings generated from oil-based muds generated from deep wells over 10,000 feet and the onshore disposal costs presented in Section XI.3.10 were used to calculate the costs incurred due to the no discharge of free oil limitation. The pollutant reductions associated with this limitation are based on the volumes of oil (organic pollutants) and TSS transported to shore for treatment/disposal. The pollutant reductions were calculated using the total volume (weight) of cuttings transported to shore and the oil content of the residual drilling fluid remaining on the cuttings.

5.1.3 BPJ Baseline: Drilling Fluids

The BPJ limitations for drilling fluids in Region VI (Gulf of Mexico) require compliance with a toxicity limitation of 30,000 ppm in the suspended particulate phase of the drilling fluid and a prohibition on the discharge of diesel oil in addition to the BPT limitations. The compliance costs and pollutant loadings incurred by industry to comply with the BPJ limitations are due to increased onshore disposal volumes resulting from failure of the toxicity test and/or in cases where diesel oil is used.

The BPJ limitations for drilling fluids in Region IX (Pacific Coast) and Region X (Alaska) require compliance with a toxicity limitation of 30,000 ppm in the suspended particulate phase, a prohibition on the discharge of diesel oil, and metals limitations in the stock barite. The compliance costs and pollutant loadings incurred by industry to comply with the BPJ limitations are due to: (1) increased onshore disposal volumes resulting from failure of the toxicity test and/or in cases where diesel oil is used and (2) a product substitution cost for clean barite.

5.1.4 BPJ Baseline: Drill Cuttings

For drill cuttings, the BPJ baseline is equal to the BPT baseline since all the regional NPDES permit limitations are equal to the BPT limitations for drill cuttings.

5.2 BCT Compliance Costs and Pollutant Removals

The BCT compliance costs and pollutant removals are due to the zero discharge limitations within certain milage delineations from shore. BCT costs and pollutant removals do not include costs and removals due to barite substitution because metals are not conventional pollutants. Also, BCT compliance costs and pollutant removals do not include costs and removals due to the failure of the toxicity test because the toxicity test does not control conventional pollutants. Tables XI-16 through XI-18 present the BCT compliance costs and pollutant removals.

5.3 BCT Incremental Compliance Costs and Pollutant Removals

The BCT incremental compliance costs and pollutant removals were determined by subtracting the BPT compliance costs and pollutant removals from the BCT compliance costs and pollutant removals.

5.4 BAT AND NSPS COMPLIANCE COSTS AND LOADINGS

The determination for the BAT and NSPS compliance costs and pollutant loadings was similar to that of the BPT/BPJ methodology, except additional costs and pollutant loadings were determined where the limitations were more stringent. These differences will be discussed in the following paragraphs.

For drilling operations in the Gulf of Mexico, clean barite was substituted for dirty barite to comply with the cadmium and mercury limitations. The metals limitation results in barite substitution costs and increased pollutant removals. Since the Region IX and X NPDES permits have metals limitations on stock barite, the drilling operations in these regions are not affected by this limitation. For the areas in the Gulf of Mexico where zero discharge limitations apply (within 0,3,4,6, or 8 miles from shore), substitution costs or pollutant reductions based on clean barite were not calculated. Tables XI-16 through XI-18 present the BAT and NSPS compliance costs and pollutant removals.

5.5 BAT AND NSPS INCREMENTAL COMPLIANCE COSTS AND POLLUTANT REMOVALS

The BAT and NSPS incremental compliance costs and pollutant removals were determined by subtracting the BPT costs and removals from the BAT/NSPS costs and removals. To relate the cumulative volume of drilling waste requiring onshore disposal to that of the model well, a value termed "well-equivalent" has been calculated. One well equivalent is equal to the volume of drilling fluid or drill cuttings generated by one regionalized (shallow or deep) model well. The total number of well equivalents determined for each geographic region was calculated by dividing the cumulative total drilling waste volume requiring onshore disposal by the volume of drilling waste generated by the model well.

Table XI-11 and XI-12 summarizes the BAT and NSPS incremental annual compliance costs and pollutant reductions obtained for the six drilling waste regulatory options. Section XI.7 provides summary tables of compliance costs, well equivalents, volumes of pollutants discharged for each regulatory option considered for the final rule.

TABLE XI-11

ANNUAL INCREMENTAL COMPLIANCE COSTS/POLLUTANT REDUCTIONS FOR REGULATORY OPTIONS - DRILLING FLUIDS

	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6
Regulatory Compliance Cost (1986 $1000/yr)	12,322	22,822	107,051	13,980	17,945	26,602
Net Decrease of Volume of Drilling Wastes Discharged (1000 bbl/yr)	411	931	5,076	493	671	1,095
Net Increase of Volume of Drilling Wastes Hauled to Shore (1000 bbl/yr)	411	931	5,076	493	671	1,095
Direct Discharges Removed	1,531	1,690	2,949	1,555	1,603	1,730
Oil Removed (1000 lb/yr)	806	1,828	9,772	968	1,180	1,976
Incidental Discharges Removed (1000 lb/yr)	25,520	57,470	311,891	30,565	41,423	67,449
TSS Removed (1000 lb/yr)	62,777	142,294	775,655	75,332	102,468	167,275

TABLE XI-12

ANNUAL INCREMENTAL COMPLIANCE COSTS/POLLUTANT REDUCTIONS FOR REGULATORY OPTIONS - DRILL CUTTINGS

	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6
Regulatory Compliance Cost (1986 $1000/yr)	6,616	10,453	41,110	7,221	8,595	11,740
Net Decrease of Volume of Drilling Wastes Discharged (1000 bbl/yr)	280	443	1,735	306	357	488
Net Increase of Volume of Drilling Wastes Hauled to Shore (1000 bbl/yr)	280	443	1,735	306	357	488
Direct Discharges Removed	203	222	379	207	211	226
Oil Removed (1000 lb/yr)	1,857	2,106	4,044	1,896	1,945	2,139
Incidental Discharges Removed (1000 lb/yr)	3,479	5,176	18,686	3,747	4,321	5,702
TSS Removed (1000 lb/yr)	128,036	205,491	818,840	140,205	164,118	226,570

6.0 BCT

Section 304(b)(4)(B) of the CWA requires EPA to take into account a variety of factors, in addition to the BCT cost test discussed below, in establishing BCT limitations. These additional factors include "non-water quality environmental impacts (including energy requirements), and such other factors as the Administrator deems appropriate." EPA conducted an investigation into both the impacts of transporting drilling wastes and the availability of land for drilling waste disposal (see section XVIII.2.2). These non-water quality environmental impacts and energy requirements and their effect on the control of drilling fluids and drill cuttings covering existing and new sources are discussed below. Also, EPA considered other factors such as administrative burden and enforcement issues in evaluating BCT options.

6.1 BCT METHODOLOGY

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

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

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

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

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

The conventional pollutant removals used in the BCT analysis are total suspended solids (TSS) and oil and grease. BOD was not used because: (1) it is not a parameter normally measured in wastewaters from this industry since it is associated with the oil content, e.g., oil and grease measurement; and (2) the use of both BOD and oil and grease would result in double-counting the pollutant removals, thus giving erroneous results.

6.2 BCT COST TEST CALCULATIONS

6.2.1 Drilling Fluids

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

$$\text{BPT Result (\$/lb)} = \frac{\$7,152,000}{47,807,000 \text{ lbs}} = \$0.1496 \text{ per pound (1986 dollars)}$$

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

$$\text{POTW Test Result (\$/lb)} = \frac{\$5{,}697{,}000}{71{,}292{,}000 \text{ lbs}} = \$0.0799 \text{ per pound (1986 dollars)}$$

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

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

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

The results of the BCT cost reasonableness test for the candidate options for drilling fluids are presented in Table XI-13. All BCT options considered for drilling fluids pass both cost-reasonableness tests.

TABLE XI-13

BCT COST TEST RESULTS FOR DRILLING FLUIDS

BCT Candidate Options	Conventional Pollutants Removed[1] (MM lb/yr)	Regulatory Compliance Cost[1] (MM \$/yr) (1986 \$)	POTW Cost Test (1986 \$/lb)	Industry Cost Test
3 Mile Gulf/CA	71.3	5.7	0.08	0.53
8 Mile Gulf/3 Mile CA	161.6	18.1	0.11	0.75
Zero Discharge Gulf and CA	879.1	116.8	0.13	0.89

[1]Incremental to BPT

6.2.2 Drill Cuttings

Using the volumes of cuttings predicted by the computer model for each geographic region, it was estimated that the offshore drilling activity annually generates a total of 846,341,000 lb/yr of conventional pollutants (TSS and oil) in the drill cuttings wastestream. Applying the BPT restrictions on free oil, it was estimated that, under BPT limitations a total of 9,381,000 lb/yr of conventional pollutants are removed from this waste stream for onshore disposal at a cost of $635,000 per year (1986 dollars). Dividing the cost by pollutant removal, the BPT cost per pound of conventional pollutant removal for drill cuttings is $0.0677 per pound (1986 dollars). The results of the BCT cost reasonableness test for the candidate options for drill cuttings are presented in Table XI-14. All BCT options considered for drill cuttings pass both cost reasonableness tests.

TABLE XI-14

BCT COST TEST RESULTS FOR DRILL CUTTINGS

BCT Candidate Options	Conventional Pollutants Removed[1] (MM lb/yr)	Regulatory Compliance Cost[1] (MM $/yr) (1986 $)	POTW Cost Test (1986 $/lb)	Industry Cost Test
3 Mile Gulf/CA	70.5	3.3	0.05	0.69
8 Mile Gulf/3 Mile CA	155.2	7.5	0.05	0.72
Zero Discharge Gulf and CA	825.3	41.0	0.05	0.73

[1]Incremental to BPT

7.0 COST AND CONTAMINANT REMOVAL SUMMARY TABLES

Summary tables of the compliance costs and pollutant removals have been prepared for all BAT and NSPS options considered. Table XI-15 identifies the regulatory option with the corresponding table presenting the compliance costs and pollutant removals. Table XI-16 and Tables XI-17a through XI-17f pertain to drilling fluids options while Tables XI-18a through XI-18f pertain to drill cuttings options.

TABLE XI-15

REGULATORY OPTIONS AND CORRESPONDING ANALYSIS DIRECTORY

Regulatory Option	Corresponding Table: Drilling Fluids	Corresponding Table: Drill Cuttings
Baseline of Current Industry Practice BPT- Drilling Fluids BPT - Drill Cuttings BPJ - Drilling Fluids	XI-16 XI-17A	XI-18A
Wells ≤ 3 miles from shore: Zero Discharge (except Alaska) Wells > 3 miles from shore: No discharge of free oil No discharge of diesel oil Toxicity: 30,000 ppm 1 mg/kg, 3 mg/kg (dry weight basis in barite stock)	XI-17B	XI-18B
Wells ≤ 3 miles from shore (California and Gulf of Mexico) Wells ≤ 8 miles from shore Zero Discharge Wells ≥ 3 miles from shore (California) Wells ≥ 8 miles from shore (Gulf of Mexico) and all wells in Alaska No discharge of free oil No discharge of diesel oil Toxicity: 30,000 ppm 1 mg/kg, 3 mg/kg (dry weight basis in barite stock)	XI-16G	XI-18G
Zero discharge from all wells (except Alaska) (Limits of toxicity, diesel oil, free oil, Hg, Cd for Alaska)	XI-17F	XI-18F
Wells ≤ 4 miles from shore: Zero Discharge (except Alaska) Wells > 4 miles from shore: No discharge of free oil No discharge of diesel oil Toxicity: 30,000 ppm 1 mg/kg, 3 mg/kg (dry weight basis in barite stock)	XI-17C	XI-18C
Wells ≤ 6 miles from shore: Zero Discharge (except Alaska) Wells > 6 miles from shore: No discharge of free oil No discharge of diesel oil Toxicity: 30,000 ppm 1 mg/kg, 3 mg/kg (dry weight basis in barite stock)	XI-17D	XI-18D
Wells ≤ 8 miles from shore: Zero Discharge (except Alaska) Wells > 8 miles from shore:	XI-17E	XI-18E

TABLE XI-16

BPT BASELINE: DRILLING FLUIDS

	Gulf of Mexico	California	Alaska	Totals
Drilling Fluids Hauled to Shore (lbs)	141,600	0	2,565	144,165
Oil Hauled to Shore (lbs)	25,293,488	0	458,152	25,751,640
TSS hauled to Shore (lbs)	21,662,803	0	392,387	20,055,190
Conventionals Hauled to Shore (lbs)	46,956,291	0	850,539	47,806,830
Transportation and Onshore Disposal Costs (1986 $)	3,014,669	0	69,222	3,083,891
Product Substitution Costs (1986 $)	3,935,537	57,183	75,399	4,068,119
Total Compliance Costs (1986 $)	6,950,206	57,183	144,621	7,152,010

TABLE XI-17A

ANNUAL POLLUTANT REMOVALS AND COST - DRILLING FLUIDS BPJ BASELINE

	Location			
	Gulf of Mexico	California	Alaska	Total
Number of "Well Equivalents" Hauled to Shore	84	2	1.5	88
Regulatory Compliance Cost (1986 $/yr)	16,571,113	325,664	361,538	17,258,315
Volume of Drilling Fluids Discharged (bbl/yr)	4,895,974	180,256	83,146	5,159,376
Volume of Drilling Fluids Hauled to Shore (bbl/yr)	711,117	11,136	12,506	734,759
% of Total Drilling Fluids Hauled to Shore	13%	6%	13%	12%
Direct Discharges (lb/yr)	2,906	43	25	2,974
Oil Discharges (lb/yr)	9,608,245	164,161	169,940	9,942,346
Incidental Discharges (lb/yr)	300,878,994	11,011,753	5,106,849	316,997,596
TSS Discharges (lb/yr)	748,090,363	27,546,714	12,703,813	788,358,890

TABLE XI-17B

ANNUAL POLLUTANT REMOVALS AND COST - DRILLING FLUIDS (3 MILE PROFILE)

	Location			
	Gulf of Mexico	California	Alaska	Total
Number of "Well Equivalents" Hauled to Shore	136.5	2	1.5	141
Regulatory Compliance Cost (1986 $/yr)	28,892,817	325,664	361,538	29,580,019
Volume of Drilling Fluids Discharged (bbl/yr)	4,485,122	180,256	83,146	4,748,524
Volume of Drilling Fluids Hauled to Shore (bbl/yr)	1,121,968	11,136	12,506	1,145,610
% of Total Drilling Fluids Hauled to Shore	20%	6%	13%	19%
Oil Hauled to Shore (lb/yr)	26,556,515	0	458,152	27,014,667
TSS Hauled to Shore (lb/yr)	91,692,247	0	392,387	92,084,634
Conventionals Hauled to Shore (lb/yr)	118,248,762	0	850,539	119,099,301
Direct Discharges (lb/yr)	1,375	43	25	1,443
Oil Discharges (lb/yr)	8,801,959	164,161	169,940	9,136,060
Incidental Discharges (lb/yr)	275,359,068	11,011,753	5,106,849	291,477,670
TSS Discharges (lb/yr)	685,313,549	27,564,714	12,703,813	725,582,076

* Alaska is exempt from zero discharge.

TABLE XI-17C

ANNUAL POLLUTANT REMOVALS AND COST - DRILLING FLUIDS (8/3 MILE PROFILE)

	Location			
	Gulf of Mexico	California	Alaska*	Total
Number of "Well Equivalents" Hauled to Shore	203	2	1.5	207
Regulatory Compliance Cost (1986 $/yr)	39,392,827	325,664	361,538	40,080,029
Volume of Drilling Fluids Discharged (bbl/yr)	3,964,712	180,256	83,146	4,228,114
Volume of Drilling Fluids Hauled to Shore (bbl/yr)	1,642,380	11,136	12,506	1,666,022
% of Total Drilling Fluids Hauled to Shore	29%	6%	13%	28%
Oil Hauled to Shore (lb/yr)	28,156,348	0	458,152	28,614,500
TSS Hauled to Shore (lb/yr)	180,396,210	0	392,387	180,788,597
Conventionals Hauled to Shore (lb/yr)	208,552,558	0	850,539	209,403,097
Direct Discharges (lb/yr)	1,216	43	25	1,284
Oil Discharges (lb/yr)	7,780,663	164,161	169,940	8,114,764
Incidental Discharges (lb/yr)	243,409,010	11,011,753	5,106,849	259,527,612
TSS Discharges (lb/yr)	605,796,252	27,564,714	12,703,813	646,064,779

* Alaska is exempt from zero discharge.

TABLE XI-17D

ANNUAL POLLUTANT REMOVALS AND COST - DRILLING FLUIDS ZERO DISCHARGE

	Location			
	Gulf of Mexico	California	Alaska*	Total
Number of "Well Equivalents" Hauled to Shore	715	32	1.5	749
Regulatory Compliance Cost (1986 $/yr)	119,386,176	4,560,971	361,538	124,308,685
Volume of Drilling Fluids Discharged (bbl/yr)	0	0	83,146	83,146
Volume of Drilling Fluids Hauled to Shore (bbl/yr)	5,607,091	191,393	12,506	5,810,990
% of Total Drilling Fluids Hauled to Shore	100%	100%	13%	98.6%
Oil Hauled to Shore (lb/yr)	40,344,552	249,005	458,152	41,051,709
TSS Hauled to Shore (lb/yr)	856,180,349	29,260,514	392,387	885,833,250
Conventionals Hauled to Shore (lb/yr)	896,524,901	29,509,519	850,539	926,884,959
Direct Discharges (lb/yr)	0	0	25	25
Oil Discharges (lb/yr)	0	0	169,940	169,940
Incidental Discharges (lb/yr)	0	0	5,106,849	5,106,849
TSS Discharges (lb/yr)	0	0	12,703,813	12,703,813

* Alaska is exempt from zero discharge.

TABLE XI-17E

ANNUAL POLLUTANT REMOVALS AND COST - DRILLING FLUIDS (4 MILE PROFILE)

	Location			
	Gulf of Mexico	California	Alaska*	Total
Number of "Well Equivalents" Hauled to Shore	147	2	1.5	151
Regulatory Compliance Cost (1986 $/yr)	30,550,710	325,664	361,538	31,237,912
Volume of Drilling Fluids Discharged (bbl/yr)	4,402,953	180,256	83,146	4,666,355
Volume of Drilling Fluids Hauled to Shore (bbl/yr)	1,204,138	11,136	12,506	1,227,780
% of Total Drilling Fluids Hauled to Shore	21.5%	6%	13%	21%
Oil Hauled to Shore (lb/yr)	26,809,120	0	458,152	27,267,272
TSS Hauled to Shore (lb/yr)	105,698,136	0	392,387	106,090,523
Conventionals Hauled to Shore (lb/yr)	132,507,256	0	850,539	133,357,795
Direct Discharges (lb/yr)	1,351	43	25	1,419
Oil Discharges (lb/yr)	8,640,701	164,161	169,940	8,974,802
Incidental Discharges (lb/yr)	270,314,321	11,011,753	5,106,849	286,432,923
TSS Discharges (lb/yr)	672,758,186	27,564,714	12,703,813	713,026,713

* Alaska is exempt from zero discharge.

TABLE XI-17F

ANNUAL POLLUTANT REMOVALS AND COST - DRILLING FLUIDS (6 MILE PROFILE)

	Location			
	Gulf of Mexico	California	Alaska*	Total
Number of "Well Equivalents" Hauled to Shore	153	23.5	1.5	178
Regulatory Compliance Cost (1986 $/yr)	31,517,814	3,323,789	361,538	35,203,141
Volume of Drilling Fluids Discharged (bbl/yr)	4,355,020	50,697	83,146	4,488,863
Volume of Drilling Fluids Hauled to Shore (bbl/yr)	1,252,072	140,696	12,506	1,405,274
% of Total Drilling Fluids Hauled to Shore	22%	73.5%	13%	24%
Oil Hauled to Shore (lb/yr)	26,956,473	178,972	458,152	27,593,597
TSS Hauled to Shore (lb/yr)	113,868,238	21,030,994	392,387	135,291,619
Conventionals Hauled to Shore (lb/yr)	140,824,711	21,209,966	850,539	162,885,216
Direct Discharges (lb/yr)	1,355	11	25	1,371
Oil Discharges (lb/yr)	8,546,635	46,170	169,940	8,762,745
Incidental Discharges (lb/yr)	267,371,555	3,097,055	5,106,849	275,575,459
TSS Discharges (lb/yr)	665,434,224	7,752,575	12,703,813	685,890,612

* Alaska is exempt from zero discharge.

TABLE XI-17G

ANNUAL POLLUTANT REMOVALS AND COST - DRILLING FLUIDS (8 MILE PROFILE)

	Location			
	Gulf of Mexico	California	Alaska*	Total
Number of "Well Equivalents" Hauled to Shore	203	29	1.5	234
Regulatory Compliance Cost (1986 $/yr)	39,392,827	4,105,911	361,538	43,860,276
Volume of Drilling Fluids Discharged (bbl/yr)	3,964,712	16,899	83,146	4,064,757
Volume of Drilling Fluids Hauled to Shore (bbl/yr)	1,642,380	174,494	12,506	1,829,380
% of Total Drilling Fluids Hauled to Shore	29%	91%	13%	31%
Oil Hauled to Shore (lb/yr)	28,156,348	225,660	458,152	28,840,160
TSS Hauled to Shore (lb/yr)	180,396,210	26,517,340	392,387	207,305,937
Conventionals Hauled to Shore (lb/yr)	208,552,558	26,743,000	850,539	236,146,097
Direct Discharges (lb/yr)	1,216	3	25	1,244
Oil Discharges (lb/yr)	7,780,663	15,390	169,940	7,965,993
Incidental Discharges (lb/yr)	243,409,010	1,032,353	5,106,849	249,549,212
TSS Discharges (lb/yr)	605,796,252	2,584,191	12,703,813	621,084,256

* Alaska is exempt from zero discharge.

TABLE XI-18A

BPT BASELINE: DRILL CUTTINGS

	Location			
	Gulf of Mexico	California	Alaska	Total
Number of "Well Equivalents" Hauled to Shore	9	0	0.2	9.2
Regulatory Compliance Cost (1986 $/yr)	621,000	0	14,000	635,000
Volume of Drill Cuttings Discharged (bbl/yr)	1,680,066	52,578	29,134	1,761,778
Volume of Drill Cuttings Hauled to Shore (bbl/yr)	26,371	0	470	26,841
% of Total Drill Cuttings Hauled to Shore	2%	0%	2%	2%
Oil Hauled to Shore (lb/yr)	464,712	0	9,391	474,103
TSS Hauled to Shore (lb/yr)	8,730,521	0	176,430	8,906,951
Conventionals Hauled to Shore (lb/yr)	9,195,233	0	185,821	9,381,054
Direct Discharges (lb/yr)	372	5	5	382
Oil Discharges (lb/yr)	3,959,659	54,806	70,304	4,084,769
Incidental Discharges (lb/yr)	18,032,029	618,099	306,384	18,956,512
TSS Discharges (lb/yr)	793,174,659	24,544,113	13,791,045	831,509,817

TABLE XI-18B

ANNUAL POLLUTANT REMOVALS AND COST - DRILL CUTTINGS (3 MILE PROFILE)

	Location			
	Gulf of Mexico	California	Alaska*	Total
Number of "Well Equivalents" Hauled to Shore	121	2	1	124
Regulatory Compliance Cost (1986 $/yr)	7,084,000	80,000	87,000	7,251,000
Volume of Drill Cuttings Discharged (bbl/yr)	1,405,445	49,741	26,597	1,481,783
Volume of Drill Cuttings Hauled to Shore (bbl/yr)	300,992	2,836	3,006	306,834
% of Total Drill Cuttings Hauled to Shore	18%	5%	10%	17%
Oil Hauled to Shore (lb/yr)	1,663,516	0	24,113	1,687,629
TSS Hauled to Shore (lb/yr)	77,973,221	0	202,302	78,175,523
Conventionals Hauled to Shore (lb/yr)	79,636,737	0	226,415	79,863,152
Direct Discharges (lb/yr)	172	4	3	179
Oil Discharges (lb/yr)	2,151,343	35,429	41,225	2,227,997
Incidental Discharges (lb/yr)	14,625,734	580,528	270,988	15,477,250
TSS Discharges (lb/yr)	667,544,621	23,260,048	12,669,829	703,474,498

* Alaska is exempt from zero discharge.

TABLE XI-18C

ANNUAL POLLUTANT REMOVALS AND COST - DRILL CUTTINGS (8/3 MILE PROFILE)

	Location			
	Gulf of Mexico	California	Alaska*	Total
Number of "Well Equivalents" Hauled to Shore	190	2	1	193
Regulatory Compliance Cost (1986 $/yr)	10,921,000	80,000	87,000	11,088,000
Volume of Drill Cuttings Discharged (bbl/yr)	1,242,370	49,741	26,597	1,318,708
Volume of Drill Cuttings Hauled to Shore (bbl/yr)	464,067	2,836	3,006	469,909
% of Total Drill Cuttings Hauled to Shore	27%	5%	10%	26%
Oil Hauled to Shore (lb/yr)	2,084,402	0	24,113	2,108,515
TSS Hauled to Shore (lb/yr)	162,262,696	0	202,302	162,484,998
Conventionals Hauled to Shore (lb/yr)	164,367,098	0	226,415	164,593,513
Direct Discharges (lb/yr)	153	4	3	160
Oil Discharges (lb/yr)	1,901,721	35,429	41,225	1,978,375
Incidental Discharges (lb/yr)	12,928,704	580,528	270,988	13,780,220
TSS Discharges (lb/yr)	590,089,062	23,260,048	12,669,829	626,018,939

* Alaska is exempt from zero discharge.

TABLE XI-18D

ANNUAL POLLUTANT REMOVALS AND COST - DRILL CUTTINGS ZERO DISCHARGE

	Location			
	Gulf of Mexico	California	Alaska*	Total
Number of "Well Equivalents" Hauled to Shore	715	32	1	748
Regulatory Compliance Cost (1986 $/yr)	40,158,000	1,500,000	87,000	41,745,000
Volume of Drill Cuttings Discharged (bbl/yr)	0	0	26,597	26,597
Volume of Drill Cuttings Hauled to Shore (bbl/yr)	1,706,437	52,578	3,006	1,762,021
% of Total Drill Cuttings Hauled to Shore	100%	100%	10%	98.5%
Oil Hauled to Shore (lb/yr)	5,290,895	54,806	24,113	5,369,814
TSS Hauled to Shore (lb/yr)	804,587,769	24,544,113	202,302	829,334,184
Conventionals Hauled to Shore (lb/yr)	809,878,667	24,598,919	226,415	834,703,998
Direct Discharges (lb/yr)	0	0	3	3
Oil Discharges (lb/yr)	0	0	41,225	41,225
Incidental Discharges (lb/yr)	0	0	270,988	270,988
TSS Discharges (lb/yr)	0	0	12,669,829	12,669,829

* Alaska is exempt from zero discharge.

TABLE XI-18E

ANNUAL POLLUTANT REMOVALS AND COST - DRILL CUTTINGS (4 MILE PROFILE)

	Location			
	Gulf of Mexico	California	Alaska*	Total
Number of "Well Equivalents" Hauled to Shore	132	2	1	135
Regulatory Compliance Cost (1986 $/yr)	7,689,000	80,000	87,000	7,856,000
Volume of Drill Cuttings Discharged (bbl/yr)	1,379,697	49,741	26,597	1,456,035
Volume of Drill Cuttings Hauled to Shore (bbl/yr)	326,740	2,836	3,006	332,582
% of Total Drill Cuttings Hauled to Shore	19%	5%	10%	18.6%
Oil Hauled to Shore (lb/yr)	1,729,972	0	24,113	1,754,085
TSS Hauled to Shore (lb/yr)	91,285,244	0	202,302	91,487,546
Conventionals Hauled to Shore (lb/yr)	93,015,216	0	226,415	93,241,631
Direct Discharges (lb/yr)	168	4	3	175
Oil Discharges (lb/yr)	2,111,929	35,429	41,225	2,188,583
Incidental Discharges (lb/yr)	14,357,781	580,528	270,988	15,209,297
TSS Discharges (lb/yr)	655,314,796	23,260,048	12,669,829	691,244,673

* Alaska is exempt from zero discharge

TABLE XI-18F

ANNUAL POLLUTANT REMOVALS AND COST - DRILL CUTTINGS (6 MILE PROFILE)

	Location			
	Gulf of Mexico	California	Alaska*	Total
Number of "Well Equivalents" Hauled to Shore	138	23.5	1	163
Regulatory Compliance Cost (1986 $/yr)	8,043,000	1,100,000	87,000	9,230,000
Volume of Drill Cuttings Discharged (bbl/yr)	1,364,677	13,990	26,597	1,405,264
Volume of Drill Cuttings Hauled to Shore (bbl/yr)	341,761	38,589	3,006	383,356
% of Total Drill Cuttings Hauled to Shore	20%	73%	10%	21%
Oil Hauled to Shore (lb/yr)	1,768,737	39,392	24,113	1,832,242
TSS Hauled to Shore (lb/yr)	99,050,590	17,641,082	202,302	116,893,874
Conventionals Hauled to Shore (lb/yr)	100,819,327	17,680,434	226,415	118,726,216
Direct Discharges (lb/yr)	167	1	3	171
Oil Discharges (lb/yr)	2,088,937	9,964	41,225	2,140,126
Incidental Discharges (lb/yr)	14,201,475	163,269	270,988	14,635,732
TSS Discharges (lb/yr)	648,180,732	6,541,888	12,669,829	667,392,449

* Alaska is exempt from zero discharge.

TABLE XI-18G

ANNUAL POLLUTANT REMOVALS AND COST - DRILL CUTTINGS (8 MILE PROFILE)

	Location			
	Gulf of Mexico	California	Alaska*	Total
Number of "Well Equivalents" Hauled to Shore	190	29	1	220
Regulatory Compliance Cost (1986 $/yr)	10,921,000	1,367,000	87,000	12,375,000
Volume of Drill Cuttings Discharged (bbl/yr)	1,242,370	4,663	26,597	1,273,630
Volume of Drill Cuttings Hauled to Shore (bbl/yr)	464,067	47,915	3,006	514,988
% of Total Drill Cuttings Hauled to Shore	27%	91%	10%	29%
Oil Hauled to Shore (lb/yr)	2,084,402	49,669	24,113	2,158,184
TSS Hauled to Shore (lb/yr)	162,282,696	22,243,103	202,302	184,728,101
Conventionals Hauled to Shore (lb/yr)	164,367,098	22,292,772	226,415	186,886,285
Direct Discharges (lb/yr)	153	0	3	156
Oil Discharges (lb/yr)	1,901,721	3,321	41,225	1,946,267
Incidental Discharges (lb/yr)	12,928,704	54,423	270,988	13,254,115
TSS Discharges (lb/yr)	590,089,062	2,180,629	12,669,829	604,939,520

* Alaska is exempt from zero discharge.

8.0 REFERENCES

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4. James P. Ray, "Offshore Discharges of Drill Cuttings," Outer Continental Shelf Frontier Technology, Proceedings of a Symposium, National Academy of Sciences, December 6, 1979. (*Offshore Rulemaking Record Volume 18*)

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9. Letter to Ann Watkins, Engineering and Analysis, U.S. Environmental Protection Agency, from Maureen Kaplan, Eastern Research Group. "Final Costs for 3,1 Stock Barite Supply," October 25, 1991.

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11. Walk, Haydel & Associates, Inc., "Water-Based Drilling Fluids and Cuttings Disposal Study Update," January 1989. Submitted as comments to 53 *FR* 41356 by the American Petroleum Institute, January 18, 1989. (*Offshore Rulemaking Record Volume 94*)

12. Offshore Operators Committee. "Response to EPA Request for Additional Information," letter from J.F. Branch, Chairman Offshore Operators Committee, to Ronald P. Jordan, Engineering and Analysis Division, U.S. Environmental Protection Agency. August 30, 1991.

13. Memorandum to Dennis Rudy, Industrial Technology Division, U.S. Environmental Protection Agency, from Harold Kohlman, KRE, P.C., "Differential Cost of Mineral Oil Substitution," June 10, 1985. (*Offshore Rulemaking Record Volume 17*)

SECTION XII

COMPLIANCE COST AND POLLUTANT LOADING DETERMINATION—PRODUCED WATER

1.0 INTRODUCTION

This section presents costs and pollutant reductions for the final set of proposed regulatory options for produced water. The technology costs represent additional investment required beyond those costs associated with BPT technologies, where applicable.

2.0 BASIS FOR BCT, BAT AND NSPS OPTION EVALUATION

Several treatment options were considered as the basis for BCT, BAT and NSPS limitations for produced water. To evaluate the proposed treatment options, EPA created a database and developed computer models to generate regionalized compliance costs for the treatment and disposal of produced water. The database consisted of the following elements:

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

EPA entered the data into the computer models designed to predict regionalized compliance costs and pollutant removals for the various regulatory options as defined in Part 6 of this section. These options are comprised of three potential treatment technologies for BAT and NSPS:

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

3.0 COMPLIANCE COSTS AND POLLUTANT REMOVAL CALCULATION METHODOLOGY

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

The per platform capital costs were regionalized using geographic area multipliers. The geographic area multipliers represent the ratios of the equipment installation costs in a particular region compared to the costs for the same equipment installation in the Gulf of Mexico region. The area multipliers are as follows:[1]

Gulf of Mexico	1.0
Pacific Coast	1.6
Alaska - Cook Inlet	2.0
Alaska - Other	3.5
Atlantic	1.6

EPA calculated total industry costs for each treatment option using; the per-platform capital and annual costs, and industry profiles of current and projected future production activity in three geographical offshore areas: the Gulf of Mexico and offshore of California and Alaska. EPA did not develop industry costs for offshore of Florida and the Atlantic coast due to the presidential moratoria on oil and gas leasing and development in these areas. However, the costs in these regions would be similar to those developed for offshore southern California.

For each geographical area, EPA characterized the industry as a population consisting of various platform structure types, or model platforms. A model platform was characterized by the number of available well slots on the platform. Each producing well is brought to the well head on the platform through a dedicated well slot. The number of well slots on a platform indicates the maximum number of producing wells. For example, the model platform Gulf 4 has four available well slots. This format is valid for all model platforms except for the Gulf 1a platform. A Gulf 1a platform consists of a centralized fluid separation process and four satellite production platforms. The model platforms were further divided into categories based on whether they produced: (1) oil only; (2) both oil and gas; or (3) gas only. The development of the industry profiles is presented in the Economic Impact Analysis for this rule.

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

As with the drilling profile, the population of BAT and NSPS structures in each region was classified within and beyond some milage delineation from shore. The milage delineations for production profiles were three and four miles from shore. Appendix 1 present the BAT and NSPS profiles of production platforms for the three and four mile delineations.

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

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

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

4.0 CAPITAL AND ANNUAL COSTS PER PLATFORM

Capital costs and annual costs were developed for the three treatment technologies considered using cost data obtained from equipment vendors and cost information supplied by the Department of Energy's Energy Information Administration (DOE/EIA). To simplify the costing task, actual equipment and annual costs were obtained for five systems with different produced water treatment capacities for each treatment technology. To estimate costs for systems with design flow rates other than the five selected, it was assumed that a linear relationship exists between the design flow rates and the capital and annual costs. The capital and annual costs obtained for the five different systems were input in computer models and, through linear interpolation, the model calculated the system costs for each model platform. This section provides a detailed discussion on the development of these costs.

4.1.1 Gas Flotation - BAT and NSPS Capital Costs

EPA developed gas flotation equipment costs based on direct contact with vendors and manufactures of offshore gas flotation equipment. Tables XII-1 and XII-2 present the BAT and NSPS unit capital costs for the five systems costed. The following discussion details the assumptions made to develop the total unit capital costs.

- **Packaged Equipment:** The packaged equipment costs are the costs for the complete gas flotation system which includes the following: a skid-mounted flotation unit, complete electrical system, oil and water outlets brought to the edge of the skid, and sufficient instrumentation for proper operation.

- **Installed Cost:** An offshore installation factor of 3.5 was used to account for costs associated with transportation to the platform and installation at the platform.[2] A conversation with an industry representative confirmed the validity of this factor by indicating that the offshore installation factor may be about three times the equipment capital costs. This consisted of transportation and installation. The transportation cost was indicated to be approximately equal to the equipment cost and the installation cost could possibly be double the equipment cost.[3]

- **Platform Addition Costs:** EPA based gas flotation space requirements on information provided by vendors and manufacturers of offshore gas flotation equipment. The existing (BAT) platform addition costs are for additional space such as a cantilevered deck. (For NSPS treatment, no platform addition or additional platform costs were incurred because EPA assumed that the space for equipment would be included in the platform design.) A cantilevered deck or wing deck can be added along one side of a platform to increase the total square footage of the platform deck. For example, a one hundred foot long cantilevered deck that extends ten feet from the edge of the existing platform deck would add one thousand square feet to the platform deck. EPA estimated the cost of additional platform space $250 per square foot based on information obtained from the industry and Department of Energy.[3,4] The actual areas required by the gas flotation systems were estimated to be twice the area of the process equipment "footprints" that were furnished by the vendors. The additional area includes sufficient space for any additional process equipment, instrumentation, and walkways. For the NSPS scenario, because new facilities can include the gas flotation equipment in the design of the platform, EPA determined that no additional platform space, such as a cantilevered deck, would be required.

- **Engineering, Contingency, and Insurance-Bonding Fees**: These fees were added to the equipment capital costs to develop the actual capital costs. These fees include all engineering design costs, administrative costs, and any incidental costs incurred in the process of purchasing and installing the equipment.[2]

TABLE XII-1

COST DATA FOR GAS FLOTATION - EXISTING PLATFORMS (BAT)

Component	Flowrate (BWPD)				
	200	1,000	5,000	10,000	40,000
1. Capital Cost (1986 $)					
Package Equipment - Installed Cost*	245,557	245,557	314,817	346,298	440,743
Engineering (10%)	24,556	24,556	31,482	34,630	44,074
Contingency (15%)	36,834	36,834	47,223	51,945	66,112
Insurance/Bonding (4%)	9,822	9,822	12,593	13,852	17,630
Platform Space	28,000	28,000	52,500	66,500	128,000
Total Capital Cost	344,769	344,769	458,615	513,225	696,559
2. Annual Cost (1986 $/yr)	34,477	34,477	45,861	51,322	69,655

*Adjusted from 1991 dollars using an ENR-CCI ratio of 4295/4775.

TABLE XII-2

COST DATA FOR GAS FLOTATION - NEW PLATFORMS (NSPS)

Component	Flowrate (BWPD)				
	200	1,000	5,000	10,000	40,000
1. Capital Cost (1986 $)					
Package Equipment - Installed Cost*	245,557	245,557	314,817	346,298	440,743
Engineering (10%)	24,556	24,556	31,482	34,630	44,074
Contingency (15%)	36,834	36,834	47,223	51,945	66,112
Insurance/Bonding (4%)	9,822	9,822	12,593	13,852	17,630
Total Capital Cost	316,769	316,769	406,115	446,725	568,559
2. Annual Cost (1986 $/yr)	31,677	31,677	40,611	44,672	56,856

*Adjusted from 1991 dollars using an ENR-CCI ratio of 4295/4775.

4.1.2 Gas Flotation - BAT and NSPS Annual Costs

The annual operating and maintenance costs for the gas flotation treatment option were assumed to be ten percent (10%) of the total capital costs for the given flow rate of the produced water stream. In addition to labor costs, typical operating and maintenance costs may include: polymer and/or flocculation enhancement chemicals, and pump and inductor maintenance and replacement costs. The annual operating and maintenance costs for the five gas flotation units are presented in Tables XII-1 and XII-2.

4.2.1 Granular Filtration - BAT and NSPS Capital Costs

The Department of Energy's Energy Information Administration (DOE/EIA) assisted the EPA in the development of capital costs for granular filtration technology. The capital costs developed are for a skid-mounted multi-media granular filtration system with a complete backwash system. Tables XII-3 and XII-4 present the BAT and NSPS unit capital costs for the five filtration systems costed. A discussion detailing the assumptions made to develop the total unit capital costs is as follows.

- **Filtration Unit**: The filtration unit costs represent the total system costs. The filters are granular media, pressure downflow type units which utilize polymer injection to enhance fine solids separation from the water stream. The filtration system includes one filter and a spare to be used during backwashing. The filtration system also includes piping around the filters, backwash basin and pumps, a backwash pump, a tank for backwash liquids, and the piping and controls necessary for recirculation of the fluids into the treatment system. The 40,000 BWPD system uses two operating filters in parallel. The following design parameters were used for equipment sizing:[4]

  Filter flow rate: 10-25 gpm/ft^2

  Filter feed pump: no pump, assume gravity feed adequate

  Media material: granular garnet and coal

  Backwash tank volume: 6,300 gal for 40,000 BWPD system

  Backwash cycle frequency: every eight hours

  Backwash cycle time: 10 minutes

  Backwash flow rate: 3% of the produced water flow

  Installation costs: included in unit costs

  Offshore transportation costs: included in unit costs.

TABLE XII-3

COST DATA FOR GRANULAR FILTRATION - EXISTING PLATFORMS (BAT)

Component	Flowrate (BWPD)				
	200	1,000	5,000	10,000	40,000
1. Capital Cost (1986 $)					
Filtration Unit*	315,000	315,000	315,000	450,000	630,000
Centrifuge**	0	128,000	128,000	128,000	256,000
Piping	47,000	66,000	66,000	66,000	88,000
Sub-Total:	362,000	509,000	509,000	644,000	974,000
Engineering (10%)	36,000	51,000	51,000	64,000	98,000
Contingency (15%)	54,000	77,000	77,000	97,000	146,000
Insurance/Bonding (4%)	14,000	20,000	20,000	26,000	39,000
Platform Space	42,000	42,000	42,000	42,000	137,000
Total Capital Cost:	508,000	699,000	699,000	873,000	1,394,000
2. Annual Cost (1986 $/yr)					
Labor	25,600	25,600	25,600	25,600	25,600
Maintenance	50,800	69,900	69,900	87,300	139,400
Chemicals	170	860	4,300	8,600	34,300
Sludge Disposal	370	1,800	9,300	18,500	74,000
Total Annual Cost:	77,000	98,100	109,100	140,000	237,300

*Adjusted from 1991 dollars using an ENR-CCI Ratio of 4295/4775
**Adjusted from 1981 dollars using an ENR-CCI Ratio of 4295/3535

TABLE XII-4

COST DATA FOR GRANULAR FILTRATION - NEW PLATFORMS (NSPS)

Component	Flowrate (BWPD)				
	200	1,000	5,000	10,000	40,000
1. Capital Cost (1986 $)					
Filtration Unit*	315,000	315,000	315,000	450,000	630,000
Centrifuge**	0	128,000	128,000	128,000	256,000
Piping	47,000	66,000	66,000	66,000	88,000
Sub-Total:	362,000	509,000	509,000	644,000	974,000
Engineering (10%)	36,000	51,000	51,000	64,000	98,000
Contingency (15%)	54,000	77,000	77,000	97,000	146,000
Insurance/Bonding (4%)	15,000	20,000	20,000	26,000	39,000
Total Capital Cost:	467,000	657,000	657,000	831,000	1,257,000
2. Annual Cost (1986 %/yr)					
Labor	25,600	25,600	25,600	25,600	25,600
Maintenance	46,700	65,700	65,700	83,100	126,000
Chemicals	170	860	4,300	8,600	34,300
Sludge Disposal	370	1,800	9,300	18,500	74,000
Total Annual Cost:	72,800	94,000	105,000	136,000	260,000

*Adjusted from 1991 dollars using an ENR-CCI Ratio of 4295/4775
**Adjusted from 1981 dollars using an ENR-CCI Ratio of 4295/3535

These costs were readjusted to represent 1986 dollars, by using the ratio of ENR-CCI indices of 4295 (1986) to 4775 (1991).

- **Centrifuge:** In order to reduce the backwash volumes that would be required to be hauled to shore, a centrifuge would be installed on the platform as part of the filtration system. The volumes of filter backwash and sludge generated after dewatering are presented in Section IX.5.2.3. Centrifuge costs are based on a centrifuge sized to process seventy five barrels of backwash concentrate per day. The cost of this unit was assumed to be no more than $30,000 in 1981 dollars.[5] This centrifuge was assumed adequate to process the backwash concentrate for all the model platforms except for systems treating less than two hundred barrels of produced water per day. For these facilities, it was assumed that the backwash volumes would be minimal and dewatering would not be necessary or economically justifiable. For costing purposes, two centrifuges were assumed adequate for systems treating more than forty thousand barrels of produced water per day. The centrifuge cost was adjusted from 1981 to 1986 dollars using the ratio of ENR-CCI indices of 4295 (1986) to 3535 (1981). The centrifuge costs presented in this Section are adjusted to 1986 dollars and include the cost for transportation and installation(offshore factor of 3.5).

- **Piping:** Piping cost represents fifteen percent (15%) of the equipment cost for systems treating 200 and 1000 BWPD and ten percent (10%) of the equipment cost for systems treating 5,000, 10,000 and 40,000 BWPD.[2]

- **Engineering, Contingency, and Insurance-Bonding Fees:** These fees were added to the equipment capital costs to develop the actual capital costs. These fees include all engineering design costs, administrative costs, and any incidental costs incurred in the process of purchasing and installing the equipment.[2]

- **Platform Space:** The platform space costs are for additional space such as a cantilevered deck. Platform addition costs were estimated by DOE/EIA and are based on the area requirements of the filtration system. EIA estimated platform addition costs to be $235 per square feet (1991 dollars). The platform addition costs were not backdated to 1986 dollars since the ENR-CCI factors are not applicable for the platform construction industry and no applicable costing factor was available. The following costs and platform space requirements were supplied by EIA:[4]

  A. Area requirements for each system

    - For 200 to 40,000 BWPD: 200 ft^2
    - For 40,000 BWPD: 600 ft^2

  B. Cost requirements for additional platform space

    - Additional area: $235/$ft^2$

  C. Cost for auxiliary platform

    - $3,500,000 for two decks, 2500 ft^2 each in deep water
    - $2,900,000 for two decks, 2500 ft^2 each in shallow water.

Cost for auxiliary platforms were only assigned to platforms with *maximum daily produced water* flow rates greater than forty thousand barrels. This consists of the Beaufort Sea, Navarian, and Pacific 70 facilities. For these model platforms, the filtration equipment would require more space than what could be added as a cantilevered deck to an existing platform. It was also assumed that the cost of an additional platform would be dependent on the water depth. In this costing exercise, all additional platforms constructed within four miles from shore were assigned the shallow water cost of $2,900,000. Those platforms beyond four miles from shore were assigned the deep water cost of $3,500,000.

4.2.2 Granular Filtration Annual Costs

The annual BAT and NSPS operating and maintenance costs for granular filtration are presented in Tables XII-3 and XII-4. The assumptions used to develop the BAT and NSPS annual costs for granular filtration are as follows:

- **Labor:** The labor costs are based on two man-hours per day at a rate of $35 per hour (1986 dollars).[4]

- **Maintenance:** Maintenance costs represent 10% of the capital costs, and include: energy costs, occasional unit cleanout, inspection of the filtration media and replacement if necessary.[4]

- **Chemicals:** The raw chemical costs are for polymer addition to enhance filtration. A dosage of 5 mg/l of polymer is assumed at a cost of $11.20/gal. This cost is in 1989 dollars and it was not backdated to 1986 dollars because it was assumed that these costs are relatively constant.[6]

- **Sludge Disposal:** EPA estimated the sludge volume generated from the granular filtration backwash stream to be 0.06% of the produced water flow.[2,5] This estimate is based on the following assumptions:

  1. Filter backwash volumes are three percent of the total volume of produced water filtered.[2]

  2. Solids contained in the backwash are at a concentration of 5,000 mg/l and are thickened to 20,000 mg/l in the backwash tank prior to dewatering[2] or approximately 0.5 percent of the total volume filtered.[5]

  3. The solids are concentrated in a centrifuge to a sludge of 25 percent solids by weight[2] or approximately 0.06 percent of the total volume filtered.[5]

  4. The cost of sludge disposal and handling is assumed to be $8.45/barrel.[5]

The volumes of backwash water and sludge generated from operation of the granular filtration units for the five model flow rates are presented in Table XII-5.

TABLE XII-5

BACKWASH AND SLUDGE VOLUMES GENERATED FROM MULTI-MEDIA FILTRATION

(volumes in barrels per day)
Flow - Barrels of Produced Water Per Day

Stream	200	1,000	5,000	10,000	40,000
Filter Backwash	6	30	150	300	1,200
Concentrated Backwash	1	5	25	50	200
Dewatered Concentrate	0.12	0.6	3	6	24

4.3.1 Reinjection-BAT and NSPS Capital Costs

Part of the basis for the reinjection costing methodology is similar to that of the granular filtration option since filtration of the produced water is typically necessary prior to reinjection. Without this pretreatment, fine solids can plug the pores of the formation, decreasing the capacity of the formation, thus preventing the reinjection of the produced water. For this costing estimation, it was assumed that multi-media filtration would be the pre-treatment filtration technology used. The DOE/EIA developed capital costs for gas turbine injection pumps. Tables XII-6 and XII-7 present the BAT and NSPS capital costs for the five granular filtration/reinjection systems costed. Several of the assumptions made to develop the capital costs for reinjection are similar to those made for the granular filtration system. The following discussion details the assumptions made in developing the capital costs for reinjection pumps and injection wells. The development of the costs for the granular filtration components of the reinjection system are discussed in Section XII.4.2.1.

- **Reinjection Pumps**: The reinjection pumps are high pressure, positive displacement pumps suitable for sea water environment. The pumps are natural gas-engine driven, and are capable of delivering 1,800 pounds per square inch of discharge head at the specified flow rate. The pump costs were developed by the EIA and include a spare.[4] These costs were adjusted to 1986 dollars by applying the ratio of ENR-CCI indices of 4295 (1986) to 4775 (1991).

- **Instrumentation and Controls**: The instrumentation and controls pertain to the injection pump and the centrifuge system. The installation and control costs are 20% of the capital costs for the injection pump and the centrifuge.[2]

TABLE XII-6

COST DATA FOR REINJECTION - EXISTING PLATFORMS (BAT)

Component	Flowrate (BWPD)				
	200	1,000	5,000	10,000	40,000
1. **Capital Cost** (1986 $)					
Disposal Pumps*	32,000	32,000	119,000	434,000	1,350,000
Instrumentation & Controls	7,000	33,000	49,000	113,000	321,000
Filtration Unit*	315,000	315,000	315,000	450,000	630,000
Centrifuge**	0	128,000	128,000	128,000	256,000
Piping	52,000	72,000	84,000	101,000	223,000
Sub-Total:	406,000	579,000	695,000	1,226,000	2,780,000
Engineering (10%)	41,000	58,000	70,000	123,000	278,000
Contingency (15%)	61,000	87,000	104,000	184,000	417,000
Insurance/Bonding (4%)	16,000	23,000	28,000	49,000	112,000
Platform Space	72,000	72,000	79,000	79,000	197,000
Total Capital Cost:	596,000	819,000	976,000	1,661,000	3,784,000
2. **Annual Cost** (1986 $/yr)					
Labor	38,300	38,300	38,300	38,300	38,300
Maintenance	59,600	81,800	97,600	166,100	378,400
Chemicals	170	860	4,300	8,600	34,300
Sludge Disposal	370	1,800	9,300	18,500	74,000
Total Annual Cost:	98,400	122,700	149,500	231,500	525,700

*Adjusted from 1991 dollars using an ENR-CCI Ratio of 4295/4775
**Adjusted from 1981 dollars using an ENR-CCI Ratio of 4295/3535

TABLE XII-7

COST DATA FOR REINJECTION - NEW PLATFORMS

Component	Flowrate (BWPD)				
	200	1,000	5,000	10,000	40,000
1. **Capital Cost** (1986 $)					
Disposal Pumps*	32,000	32,000	119,000	434,000	1,350,000
Instrumentation & Controls	6,000	32,000	49,000	113,000	321,000
Filtration Unit*	315,000	315,000	315,000	450,000	630,000
Centrifuge**	0	128,000	128,000	128,000	256,000
Piping	53,000	72,000	56,000	101,000	224,000
Sub-Total:	406,000	579,000	667,000	1,226,000	2,781,000
Engineering (10%)	41,000	58,000	67,000	122,000	278,000
Contingency (15%)	61,000	87,000	100,000	184,000	417,000
Insurance/Bonding (4%)	16,000	23,000	27,000	49,000	111,000
Total Capital Cost:	524,000	747,000	861,000	1,581,000	3,587,000
2. **Annual Cost** (1986 $/yr)					
Labor	38,300	38,300	38,300	38,300	38,300
Maintenance	52,300	74,600	86,100	158,100	358,700
Chemicals	170	860	4,300	8,600	34,300
Sludge Disposal	370	1,800	9,300	18,500	74,000
Total Annual Cost:	91,200	115,600	138,000	223,500	505,300

*Adjusted from 1991 dollars using an ENR-CCI ratio of 4295/4775
**Adjusted from 1981 dollars using an ENR-CCI ratio of 4295/3535

- **Platform Space:** The platform space costs for the reinjection technology are similar to the cost developed for the granular filtration option. The reinjection system requires additional space beyond that required for granular filtration due to the area requirements of the injection pump. The EIA estimated that the area requirements for injection pumps on platforms processing up to 40,000 barrels of produced water per day is 140 square feet and the area requirement for a 40,000 barrel per day system is approximately 250 square feet. For those facilities processing over 40,000 barrels per day construction of auxiliary platforms would be necessary.[4]

- **Reinjection Wells:** The reinjection wells costs are based on $750,000 per well to recomplete an existing available well bore and $1,500,000 per well to drill a new well bore.[7] These estimates are based (up to 5,000 ft true vertical depth) wells drilled in the Gulf of Mexico. on actual costs for similar depth Each well has a flow capacity of 6,000 BWPD. It was assumed that available slots not utilized for producing wells on model platforms are "dry holes" and can be converted to injection wells.[8] The number of injection wells required per structure was calculated based on that platforms average daily produced water flow rate. It was assumed that for every two wells required, one spare well would be necessary to handle the injection flow requirements if there was a problem with the two operating wells. For fields producing less than 1,000 BWPD, it was assumed that only one injection well was necessary. These fields would either shut down during an injection well workover or would have sufficient water holding capacity to continue production operations. These costs were adjusted from 1991 dollars to represent 1986 dollars by applying the ratio of ENR-CCI indices of 4295 (1986) to 4775 (1991). The well costs were added into the capital costs in the model, where the number of existing wells, the number of wells to be reworked, and the number of new wells to be drilled is estimated for each structure type.

4.3.2 Reinjection Annual Costs Assumptions

The annual operating and maintenance costs for reinjection are presented in Tables XII-6 and XII-7. The assumptions used to develop the BAT and NSPS annual costs for reinjection are the same as the assumptions used for granular filtration except for additional labor requirements. The labor requirements for granular filtration are as follows:

- **Labor:** The labor costs are based on two man-hours per day at a rate of $35 per hour (1986 dollars). An additional one man-hour per day was added to the base cost for the operation and maintenance of the reinjection system.[4]

5.0 REGIONAL AND TOTAL INDUSTRY COSTS

The regional costs were calculated based on the per-platform capital and annual costs developed and the number of platforms within each geographical region. For the purposes of determining produced water compliance costs for this rule, EPA assumed that all new sources would be new platforms and no allowances were made to account for existing platforms being moved to new locations. An existing platform moved to a new location would be classified as a new source; however, EPA was unable to determine the extent to which existing platforms would be used to develop new hydrocarbon reserves.

Compliance costs for all existing platforms are included as BAT costs in this rule. Also, EPA is unaware of any existing contractual obligations which could result in new platforms being classified as existing sources. For this rule, new platforms are included as new sources.

Based on information from the Department of Energy and as presented in the March 1991 proposal, EPA estimated that thirty-seven percent (37%) of existing platforms in the Gulf of Mexico currently pipe their produced water to shore for treatment.[9] Therefore when developing the regional costs for the Gulf of Mexico, only sixty-three percent (63%) of the total number of existing platforms and one hundred percent (100%) of new platforms were assigned offshore treatment costs. Onshore treatment costs were assigned to those facilities currently piping to shore. Onshore treatment costs are detailed in Section XII.5.2. EPA cost projections for new platforms indicate that the cost of offshore treatment will be less than the combined cost of installing piping and establishing onshore treatment facilities. Thus, EPA assumed all new sources will treat water offshore. The total industry costs for the granular filtration and the reinjection option are the sum of the regional costs for each treatment option. The total industry compliance costs as they pertain to the regulatory options considered are presented in Section XII.8.1.

The total capital costs for gas flotation were more complicated to determine because many operators currently use the gas flotation technology to comply with the current BPT regulations. To avoid over-costing by assigning capital costs to all platforms, EPA made several assumptions to predict the number of existing platforms that currently have gas flotation systems and the number of platforms that will have to install new flotation systems. The following sections detail the assumptions made in estimating the total industry costs for the gas flotation option.

5.1.1 Gas Flotation - BAT Total Industry and Capital Costs

EPA determined that to achieve BAT oil and grease limitations based on improved performance of gas flotation technology, operators who currently have gas flotation treatment systems would continue to use the same treatment units, although some changes to those systems or their manner of operation might be necessary. For existing platforms that do not currently have gas flotation systems and can not meet the limitations of the final rule with their existing treatment systems, some form of add-on treatment would be necessary. For costing purposes, EPA assumed that all facilities currently without gas flotation systems are unable to meet the BAT (or for new sources, NSPS) limitations and flotation units would need to be installed. This assumption does not take into consideration the fact that other treatment technologies currently used by the operators, such as: parallel plate separators, corrugated plate interceptors, hydro-cyclones, or filtration, may enable operators to meet the effluent limitation without requiring installation of flotation units. (The establishment of an effluent limitation based on a given technology does not require use of the treatment technology upon which the limitation is based. EPA selects a technology basis to demonstrate that the effluent limitations are technologically feasible and economically achievable.) A report prepared in 1984 for the Offshore Operators Committee (OOC) found that thirteen percent of 319 outer continental shelf (OCS) facilities surveyed used flotation systems for treatment of produced water.[10] Since that same study noted that nearly all new platforms were expected to install gas flotation systems for produced water treatment; and considering that the profile would likely have changed in the years since that survey was conducted, EPA collected information from the Minerals Management Service and various industry sources to update projections of existing gas flotation systems. EPA learned from MMS, which in 1990 conducted 1,667 drilling inspections and 4,830 production inspections,[11] that approximately thirty-five percent (35%) of the offshore facilities in Gulf of Mexico are now using gas flotation systems for produced water treatment.[12]

In developing the estimate of the current usage of gas flotation technology in the offshore industry, EPA contacted several members of the OOC. Although estimates of gas flotation usage varied between companies (some operators indicated 100% usage while others indicated partial usage), most operators indicated that gas-only production facilities were the least likely to use gas flotation to treat produced water. The operators indicated that this is because for gas production, an easy separation exists between the produced water and the condensate and/or oil. Some gas production facilities can meet the BPT limitations on oil and grease with basic gravity separation. However, for most oil production facilities, treatment with gas flotation or some other add-on treatment technology is necessary to achieve the BPT limitations on oil and grease. This is because often an emulsion is created between the oil and produced water and additional treatment beyond gravity separation is necessary to assure BPT compliance.

To characterize the variation of gas flotation usage between gas only, oil and gas, and oil only production projects, EPA developed a distribution profile of facilities currently using gas flotation technology for the three different types of production facilities. Since the produced water flow rates are significantly different from a "gas only" and a "oil only" project, a distribution profile is necessary to accurately estimate the gas flotation capital and annual O&M costs for each production type. Applying a straight profile of thirty-five percent for each production type would lead to overcounting of large flow, higher cost flotation systems for "oil only" projects and undercounting of low flow, lower cost flotation systems for "gas only" projects. The distribution profile is as follows:

Production Type	Existing Gas Flotation Systems
Gas production	20%
Oil and Gas production	40%
Oil production	60%

This distribution profile is based on the estimate that thirty-five percent (35%) of offshore operators use gas flotation technology and the general fact that less "gas only" platforms currently have gas flotation systems than "oil only" platforms.[12] The aggregate number of platforms for each production type with gas flotation units equals thirty-five percent of the total platform population. Although EPA is unaware of any data of gas flotation usage in the offshore industry to verify the distribution profile, EPA is confident that the profile accurately parallels the actual gas flotation population and for costing purposes it provides a conservative basis for developing industry compliance costs. Total industry gas flotation capital costs were based on the number of facilities that do not currently have gas flotation units.

5.1.2 Gas Flotation - BAT Annual Costs

EPA calculated the BAT annual operating and maintenance (O&M) costs using the gas flotation distribution profiles discussed in the preceding section. For those platforms that already have gas flotation units installed, the annual O&M costs of complying with BAT limitations based gas flotation are estimated to be higher than their current annual O&M costs because of modifications and enhancements needed to improve system performance. Enhanced removals of oil and grease can be achieved by existing gas flotation systems through closer supervision of the units by the platform operators, additional monitoring of the systems operating parameters, proper sizing of the unit to improve hydraulic loading, additional maintenance of the process equipment, and addition and/or proper usage of flocculation enhancement chemicals. These costs are incremental to the current annual costs. EPA estimates that the additional labor and other improvements necessary to achieve compliance with BAT limits will approximately double the annual O&M costs for existing flotation systems currently achieving BPT quality effluent. Since BAT facilities needing to install a gas flotation unit (or other technology) to comply with the limit would design and select a treatment system to meet the BAT oil and grease limit, additional O&M costs would not be incurred. Total annual O&M costs for existing platforms that will need to install gas flotation were determined to be approximately ten percent (10%) of the capital costs of the new flotation system. EPA notes that the BAT and NSPS limitations of the final rule are based on data from existing facilities identified as being representative of platforms having well-operated gas flotation units. Thus, although not all existing facilities with gas flotation units would be expected to already be meeting the BAT and NSPS oil and grease limits of this rule, the data shows that a portion of the industry can already comply with the limitations of this final rule without incurring an additional cost. Because EPA does not know how many of these facilities would be able to comply without incurring additional cost, no allowance is made in EPA's cost projections to exclude such facilities in determining the cost of compliance for this rule. Thus, EPA is confident that compliance costs are not underestimated, and likely to be somewhat overestimated. On balance, however, EPA believes these cost projections are representative of the aggregate compliance costs for the entire subcategory.

5.1.3 Gas Flotation - NSPS Total Industry Capital Costs

The 1984 OOC report stated that even in the absence of produced water limitations more stringent than BPT, eighty percent (80%) of new platforms would be designed with gas flotation systems for treatment of produced water.[10] EPA based compliance cost projections on the assumption that in the absence of NSPS limitations 20 percent of new platforms would not include a flotation unit in their treatment system design. This 20 percent of new platforms is considered to incur an incremental cost to comply with NSPS limitations. In estimating NSPS capital costs, EPA assumed that it was necessary for the operator to add-on a complete flotation system. The entire costs for adding on such a system were used in EPA's economic impact analyses. EPA notes that although some new platforms would not have planned to install flotation systems, the platforms would have contained some other type of treatment technology and it is entirely possible that the alternative system would enable compliance without incurring additional costs to comply with the NSPS limitations. EPA also notes that by adding on a flotation system to comply with NSPS limits the operator may actually forego installation of other produced water treatment units, with the result being that the gas flotation unit would serve as a replacement system rather than an add-on system, incurring no, or reduced, incremental costs. However, in costing this rule it has been assumed that an add-on treatment system will be required and costs of entire flotation systems for 20 percent of all new sources have been included.

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

5.1.4 Gas Flotation - NSPS Total Industry Annual Costs

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

5.2 ONSHORE DISPOSAL COSTS

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

The onshore treatment costs were evaluated for both the BAT and NSPS scenarios. However, for the NSPS scenario, EPA projects that the cost to install piping to the offshore facility would greatly exceed the costs of installing the necessary treatment control technology onsite at the offshore platforms. Thus, it is assumed no new sources will pipe produced water to shore for treatment.

The basis for the onshore treatment system costs are similar to the offshore per-platform system costs, although there are a few exceptions. The exceptions are: (1) the offshore installation factor (a multiplier applied to onshore costs to account for the increased cost of transporting and installing equipment offshore) of 3.5 was not used; (2) there were no platform addition costs; (3) no centrifuge cost was assigned for onshore filtration or reinjection; and (4) the cost for the installation of injection wells was estimated at $155,000 (1986 dollars).[13] EPA assumed that a centrifuge would be unnecessary to dewater the filter backwash because adequate space would be available at an onshore treatment facility. The centrifuge is assumed to be needed on offshore platforms because of the limited space available to capture, settle and store backwash volumes from the granular filter.

Table XII-8 and XII-9 present the onshore capital and annual costs for the gas flotation, granular filtration, and reinjection technologies. Tables XII-10 and XII-11 present the regional and total capital and annual costs for onshore gas flotation, granular filtration, and reinjection at both the three and four milage delineations.

TABLE XII-8

BAT ONSHORE TREATMENT CAPITAL COSTS (COST IN 1986 DOLLARS)

	System Flow Rate - Barrels of Produced Water Per Day				
	200	1,000	5,000	10,000	40,000
Gas Flotation*	90,505	90,505	116,032	127,636	162,445
Granular Filtration*	133,515	187,769	187,796	237,526	359,210
Reinjection*	160,832	170,313	214,649	404,392	908,175

*Adjusted from 1991 dollars using an ENR-CCI Ratio of 4295/4775.

TABLE XII-9

BAT ONSHORE TREATMENT ANNUAL COSTS (COST IN 1986 DOLLARS)

	System Flow Rate - Barrels of Produced Water Per Day				
	200	1,000	5,000	10,000	40,000
Gas Flotation	9,505	9,051	11,603	12,764	16,245
Granular Filtration	13,892	21,437	32,377	50,853	144,221
Reinjection	16,623	19,691	35,649	67,539	199,118

TABLE XII-10

BAT - GULF OF MEXICO ONSHORE COMPLIANCE COSTS: 3 MILE PROFILE

	Gulf of Mexico		Total
	≤ 3	>3	
Capital Costs			
Flotation	2,597,529	64,125,816	66,723,345
Filtration	4,561,941	110,536,066	115,098,007
Reinjection	9,896,552	246,026,369	255,922,921
O&M Costs			
Flotation	258,962	6,189,233	6,448,195
Filtration	1,094,053	26,838,862	27,932,915
Reinjection	3,434,251	88,611,928	92,046,179

TABLE XII-11

BAT - GULF OF MEXICO ONSHORE COMPLIANCE COSTS: 4 MILE PROFILE

	Gulf of Mexico		Total
	≤ 4	>4	
Capital Costs			
Flotation	6,837,250	59,886,094	66,723,344
Filtration	12,061,468	103,036,539	115,098,007
Reinjection	28,310,413	267,612,508	295,922,921
O&M Costs			
Flotation	678,706	5,769,490	6,448,196
Filtration	2,905,422	25,027,493	27,932,915
Reinjection	9,258,965	82,787,214	92,046,179

6.0 BCT OPTIONS CONSIDERED

The five options selected for final consideration in developing BCT limitations for produced water discharges were based on reinjection, gas flotation, or granular filtration technologies.

- **Option 1**: BPT All Structures: EPA included as an option setting BCT equal to BPT. By doing so, EPA realized that the removals of conventional pollutants due to compliance with stricter standards may not be cost reasonable under the BCT cost tests.

- **Option 2:** Flotation All: All discharges of produced water, regardless of the water depth or distance from shore at which they are located, would be required to meet limitations on oil and grease content at 29 mg/l monthly average and a daily maximum of 42 mg/l. The technology basis for these limits is improved operating performance of gas flotation.

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

- **Option 4:** Zero Discharge Gulf and Alaska: This option would prohibit all discharges of produced water based on reinjection of the produced water. All facilities off California and all currently existing single-well dischargers in the Gulf of Mexico would be excluded from zero discharge limitation. They would, however, be required to comply with the oil and grease limitations developed based on improved operating performance of gas flotation technology.

- **Option 5:** Filter 4 miles Gulf and Alaska: Wells located at a distance of 4 nautical miles or less from shore would be required to meet oil and grease limitations of 16 mg/l monthly average and 29 mg/l daily maximum based on granular filtration technology. Facilities located more than 4 miles from shore would be required to meet the existing BPT oil and grease limitations of 48 mg/l monthly average and 72 mg/l daily maximum.

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

7.0 BAT AND NSPS OPTIONS CONSIDERED

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

The options considered for NSPS are similar to those considered for BAT, with the only exception being that the exclusion for single-well dischargers (Gulf Ib) from the zero discharge limitation is not applicable under NSPS. This exclusion was developed because of the costs, economic impacts and production impacts associated with requiring single-well dischargers currently in operation to retrofit filtration and reinjection equipment. Since new sources are able to allow for adequate space in designing new facilities and compliance costs are less for the new sources, economic and production impacts on these facilities are significantly reduced.

8.0 OPTION EVALUATION

An analysis of each regulatory option was conducted to determine:

- Incremental costs incurred by industry to comply with the regulation.
- Reduction of pollutants discharged to the surface waters.

The following sections present the analysis of each regulatory option.

8.1 BCT, BAT AND NSPS INCREMENTAL COMPLIANCE COSTS

The BCT and BAT incremental costs are the same for each option because oil and grease is the only regulated pollutant in produced water (oil and grease is considered both a conventional and an indicator for toxic pollutants for this rule). The incremental compliance costs are equal to the total compliance incurred under BCT or BAT because all of the regulatory options, besides the BPT All option (which incurs zero incremental costs), are add-on technologies. Except in the case where existing gas flotation systems exist and in this case the compliance costs are incremental to the current BPT compliance costs. Table XII-12 presents the BCT and BAT incremental compliance costs for the five regulatory options.

The incremental costs for NSPS are also equal to the total costs for the add-on technology except for the facilities that have gas flotation systems in the design plans for future platforms. In this case the design upgrade costs are considered incremental to original design and capital costs included in the financial projection of that production operation. Table XII-13 presents the NSPS incremental compliance costs for the five regulatory options.

TABLE XII-12

SUMMARY OF INCREMENTAL COSTS AND CONTAMINANT REMOVAL - BAT

Options	Capital Cost ($000)	Annual O&M Cost ($000/yr)	Pollutant Reduction (lb/yr)			
			Conventional	Metals	Organics	Total Radium
Option 1 **BPT All**	0	0	0	0	0	0
Option 2 **Improved Gas Flotation All**	382,488	46,598	9,611,917	12,934,384	2,531,860	0.0197
Option 3 **Zero Discharge Within 3 Miles** (Gulf and Alaska) Exemption: Gulf 1b and California - Improved Gas Flotation **Improved Gas Flotation Beyond 3 Miles**	465,470	54,147	9,768,688	13,199,699	2,552,511	0.0218
Option 4 **Zero Discharge All** (Gulf and Alaska) Exemption: Gulf 1b and California - Improved Gas Flotation	2,698,632	292,531	20,111,718	30,702,408	3,914,715	0.1607
Option 5 **Granular Filtration Within 4 Miles** (Gulf of Mexico, California, Alaska) **BPT Beyond 4 Miles**	158,106	14,250	1,839,391	306,626	41,473	0.0024

TABLE XII-13

SUMMARY OF INCREMENTAL COMPLIANCE COSTS AND CONTAMINANT REMOVAL–NSPS

Options	Capital Cost ($000)	Annual O&M Cost ($000/yr)	Pollutant Reduction (lb/yr)			
			Conventional	Metals	Organics	Total Radium
OPTION 1 **BPT All**	0	0	0	0	0	0
OPTION 2 **Improved Gas Flotation All**	84,936	5,066	6,059,111	5,253,258	1,028,305	0.0080
OPTION 3 **Zero Discharge Within 3 Miles** (Gulf and Alaska) Exemption: California - Improved Gas Flotation **Improved Gas Flotation Beyond 3 Miles**	435,432	26,432	7,357,669	6,655,486	1,137,436	0.0191
OPTION 4 **Zero Discharge All** (Gulf and Alaska)Exemption: California - Improved Gas Flotation	2,346,308	156,310	14,370,969	14,315,268	1,733,585	0.0800
OPTION 5 **Granular Filtration Within 4 Miles** (Gulf of Mexico, California, Alaska) **BPT Beyond 4 Miles**	90,231	9,124	1,581,232	168,326	22,767	0.0130

8.2 BCT, BAT AND NSPS POLLUTANT REMOVALS

The incremental pollutant removals associated with BAT and NSPS treatment technologies are determined by comparing the effluent levels after treatment by BAT/NSPS technologies (flotation, granular filtration, or reinjection) with the effluent levels associated with a typical BPT treatment (gas flotation or gravity separation).

8.2.1 Gas Flotation and Granular Filtration Effluent Characterization

Characterizations of produced water effluent from granular filtration were obtained through a statistical analysis of data collected during EPA's three facility study.[14]

The characterizations of produced water effluent from gas flotation were obtained through a statistical analysis of data collected by EPA and submitted by industry.[15] The data used to develop gas flotation effluent estimates are from the OOC 10 Platform Database, the OOC 42 Platform Study, and the Thirty Platform Study. The total oil and grease concentrations available from this data were taken for 455 samples from 60 platforms, using well performing platforms and screening for BPT compliance. Appendix 2 presents the data from the above sources. The variation estimates for total oil and grease from this data subset are presented in Table XII-14.

TABLE XII-14

TOTAL OIL AND GREASE VARIATION ESTIMATES
PHYSICAL COMPOSITING - SCREENED FOR BPT COMPLIANCE

Parameters	Estimate
Delta (δ)	0.0044
Mean concentration (EX)	23.2256
Log-mean (μ_m)	3.0563
Log-mean adjusted for 4 grab samples (μ_4)	3.1197
Log-mean adjusted for 4 composite samples ($\mu_{4(4)}$)	3.1357
Process variation (σ^2_p)	0.1578
Measurement variation (σ^2_m)	0.0285
Process variation of 4 grab samples (σ^2_{p4})	0.0441
Measurement variation of 4 grab samples (σ^2_{c4})	0.0726
Process variation of 4 composite samples ($\sigma^2_{c4(4)}$)	0.0190
The estimated long-term average and limitations for total oil and grease from Data Set Three are: • Long-Term Average = 23.5 mg/l • Daily Maximum = 42.4 mg/l • Monthly Average = 28.9 mg/l.	

Table XII-15 presents the produced water effluent characteristics following BPT-level treatment and BCT/BAT/NSPS-level treatment.[16]

TABLE XII-15

POLLUTANT LOADING CHARACTERIZATION — PRODUCED WATER[16]

Pollutant Parameter	BPT-Level Effluent	Improved Gas Flotation Effluent	Granular Filtration Effluent
	Concentrations mg/l		
Oil & Grease	25.0	23.5	11.33[14]
TSS	67.5	30.0[15]	21.17[14]
	Concentrations $\mu g/l$		
Priority and Non-conventional Organic Pollutants:			
2-Butanone	1028.96	411.58	926.06
2,4-Dimethylphenol	317.13	250.00	285.41
Anthracene	18.51	7.40	16.66
Benzene	2978.69	1225.91	2875.92
Benzo(a)pyrene	11.61	4.65	10.45
Chlorobenzene	19.47	7.79	17.52
Di-n-butylphthalate	16.08	6.43	14.47
Ethylbenzene	323.62	62.18	297.02
n-Alkanes	1641.50	656.60	1477.35
Naphthalene	243.58	92.02	176.81
p-Chloro-m-cresol	25.24	10.10	22.34
Phenol	1538.28	536.00	1384.46
Steranes	77.50	31.00	69.75
Toluene	1897.11	827.80	1749.14
Triterpanes	78.00	31.20	70.20
Total xylenes	695.03	378.01	664.45
Priority and Non-conventional Metal Pollutants:			
Aluminum	78.01	49.93	34.30
Arsenic	114.19	73.08	15.81
Barium	55563.80	35560.83	51624.33
Boron	25740.25	16473.76	25593.53
Cadmium	22.62	14.47	18.09
Copper	444.66	284.58	418.65
Iron	4915.87	3146.15	3618.57
Lead	195.09	124.86	156.07
Manganese	115.87	74.16	110.19
Nickel	1705.46	1091.49	1364.37
Titanium	7.00	4.48	5.83
Zinc	1190.13	133.85	832.38
Radionuclides:			
Radium 226	0.00022628	0.00020365	0.00020365
Radium 228	0.00027671	0.00024904	0.00024904

Note

Radium values are based only on averages of the OOC 44 platform study and are used to approximate radium removal. The values are based on concentrations in picocuries per liter and are as follows:
(1) Average Radium-226 estimated at 226.28 pCi/l.
(2) Average Radium-228 estimated at 276.71 pCi/l.

8.2.2 Annual BCT/BAT/NSPS Pollutant Removals

Computer models were developed to calculate pollutant removals for the five treatment options on a regional basis using the model flow and contaminant removal data. BAT and NSPS pollutant removal quantities for each option were calculated by multiplying the average produced water flow rate for each model platform by the difference in pollutant concentrations in BPT effluent and BAT or NSPS effluent concentrations.

Table XII-16 presents the annual volumes of produced water treated and discharged offshore for existing structures (BAT flow rates) and for new structures (NSPS flow rates). These volumes are based on the yearly average produced water flow rates presented in Appendix 1 and do not include produced water flows from existing (BAT) structures which currently treat produced water onshore (thirty-seven percent of all existing structures pipe produced water to shore for treatment).

TABLE XII-16

ANNUAL PRODUCED WATER DISCHARGES (bbl/yr)

	Gulf of Mexico		Pacific	Alaska
	All Structures	All Structures Except 1Bs	All Structures	All Structures
BAT				
Within 3 miles	9,263,996	8,361,212	36,797,749	0
Beyond 3 miles	559,867,083	551,635,103	97,310,701	0
Total	569,131,079	559,996,315	134,108,450	0
Within 4 miles	35,957,511	34,001,327	51,516,848	0
Beyond 4 miles	533,173,568	525,994,988	82,591,601	0
Total	569,131,079	559,996,315	134,108,449	0
NSPS				
Within 3 miles	31,761,205	31,704,995	0	35,532,020
Beyond 3 miles	345,481,625	343,927,455	0	9,287,060
Total	377,242,830	375,632,450	0	44,819,080
Within 4 miles	37,420,895	37,303,365	0	35,532,0206
Beyond 4 miles	339,821,935	338,329,085	0	9,287,060
Total	377,242,830	375,632,450	0	44,819,080

Pollutant removals were determined for each regulatory option considered and are presented in Tables XII-17 and XII-18 for BAT and NSPS respectively. The terms organics and metals represents those analytes presented in Table XII-15 and conventionals refers to oil and grease and TSS.

TABLE XII-17

BAT ANNUAL REGIONALIZED POLLUTANT REMOVALS[16]
(POUNDS)

	Within[1]			Beyond[1]			
	Gulf of Mexico	Pacific	Sub-Total	Gulf of Mexico	Pacific	Sub-Total	Total
Option 1	0	0	0	0	0	0	0
Option 2							
Conventional	126,621	502,954	629,574	7,652,294	1,330,048	8,982,342	9,611,917
Organics	33,356	132,479	165,835	2,015,692	350,333	2,366,025	2,531,860
Metals	170,408	676,787	847,195	10,297,453	1,789,736	12,087,189	12,934,384
Radium 226	0.0001	0.0005	0.0006	0.0070	0.0012	0.0083	0.0089
Radium 228	0.0001	0.0006	0.0007	0.0086	0.0015	0.0101	0.0108
Option 3							
Conventionals	283,392	502,954	786,345	7,652,294	1,330,048	8,982,342	9,768,688
Organics	54,007	132,479	186,486	2,015,692	350,333	2,366,025	2,552,511
Metals	435,723	676,787	1,112,510	10,297,453	1,789,736	12,087,189	13,199,699
Radium 226	0.0011	0.0005	0.0015	0.0070	0.0012	0.0087	0.0098
Radium 228	0.0013	0.0006	0.0019	0.0086	0.0015	0.0101	0.0120
Option 4							
Conventionals	283,392	502,954	786,345	17,995,325	1,330,048	19,325,373	20,111,718
Organics	54,007	132,479	186,486	3,377,894	350,335	3,728,229	3,914,715
Metals	435,723	676,787	1,112,510	27,800,162	1,789,736	29,589,898	30,702,408
Radium 226	0.0011	0.0005	0.0015	0.0695	0.0012	0.0708	0.0723
Radium 228	0.0013	0.0006	0.0019	0.0850	0.0015	0.0865	0.0884
Option 5							
Conventionals	756,107	1,083,285	1,839,391	0.0	0.0	0.0	1,839,391
Organics	17,049	24,424	41,473	0.0	0.0	0.0	41,473
Metals	126,051	180,575	306,626	0.0	0.0	0.0	306,626
Radium 226	0.0005	0.0006	0.0011	0.0	0.0	0.0	0.0011
Radium 228	0.0006	0.0008	0.0013	0.0	0.0	0.0	0.0013

[1]For all Options, Alaska has been removed since there are no BAT structures.
[2]Radium values are based only on averages of the OOC 44 platform study and are used to approximate radium removal. The values are based on concentrations in picocuries per liter and are as follows:
(1) Average Radium-226 estimated at 226.28 pCi/l.
(2) Average Radium-228 estimated at 276.71 pCi/l.

TABLE XII-18

NSPS ANNUAL REGIONALIZED POLLUTANT REMOVALS[16]
(POUNDS)

	Within[1]			Beyond[1]			
	Gulf of Mexico	Alaska	Sub-Total	Gulf of Mexico	Alaska	Sub-Total	Total
Option 1	0	0	0	0	0	0	0
Option 2							
Conventionals	460,959	485,654	946,612	4,985,563	126,936	5,112,499	6,509,111
Organics	78,527	80,591	159,118	848,126	21,061	869,187	1,028,305
Metals	401,171	411,703	812,874	4,332,777	107,607	4,440,384	5,253,258
Radium 226	0.0003	0.0003	0.0006	0.0030	0.0001	0.0030	0.0036
Radium 228	0.0003	0.0003	0.0007	0.0036	0.0001	0.0037	0.0044
Option 3							
Conventionals	1,093,300	1,151,821	2,245,171	4,985,563	126,936	5,112,949	7,357,669
Organics	132,388	135,861	268,249	848,126	21,061	869,187	1,137,436
Metals	1,093,201	1,121,901	2,215,102	4,332,777	107,607	4,440,384	6,655,486
Radium 226	0.0027	0.0028	0.0056	0.0030	0.0001	0.0030	0.0086
Radium 228	0.0034	0.0034	0.0068	0.0036	0.0001	0.0037	0.0105
Option 4							
Conventionals	1,093,300	1,151,871	2,245,171	11,824,732	301,066	12,125,798	14,370,969
Organics	132,388	135,861	268,249	1,429,826	35,510	1,465,336	1,733,585
Metals	1,093,201	1,121,901	2,215,102	11,806,933	293,233	12,100,166	14,315,268
Radium 226	0.0027	0.0028	0.0056	0.0297	0.0007	0.0304	0.0360
Radium 228	0.0034	0.0034	0.0068	0.0363	0.0009	0.0372	0.0440
Option 5							
Conventionals	834,073	747,159	1,581,232	0.0	0.0	0.0	1,581,232
Organics	12,155	10,612	22,767	0.0	0.0	0.0	22,767
Metals	89,864	78,462	168,326	0.0	0.0	0.0	168,326
Radium 226	0.0003	0.0003	0.0006	0.0	0.0	0.0	0.0006
Radium 228	0.0004	0.0003	0.0007	0.0	0.0	0.0	0.0007

[1]For all Options, Pacific has been removed since the there are no NSPS Structures.
[2]Radium values are based only on averages of the OOC 44 platform study and are used to approximate radium removal. The values are based on concentrations in picocuries per liter and are as follows:
(1) Average Radium-226 estimated at 226.28 pCi/l.
(2) Average Radium-228 estimated at 276.71 pCi/l.

9.0 BCT COST TEST

The BCT cost test methodology produced water is the same as that described in Section XI.7.0. The pollutant parameters used in this analysis are total suspended Solids (TSS) and oil and grease. Refer to Table XII-12 for a summary of incremental costs and conventional pollutant removals for each regulatory option.

9.1 BCT COST TEST CALCULATIONS

All of the produced water options considered for BCT regulation fail the BCT cost test except for the BCT option equal to BPT. For every option, except BPT All, the ratio of cost of pollutant removal to pounds of pollutant removed (POTW Test) exceeds the POTW benchmark of $0.46 per pound. Table XII-19 presents the BCT Cost Test Analysis.

TABLE XII-19

PRODUCED WATER BCT COST TEST

Option	Pollutant Removals (lbs)	Peak Annualized Costs ($/yr)	POTW Cost Ratio ($/lb)	Pass POTW?
Option 1	0	0	0	Yes
Option 2	9,611,917	96,290,000	10.02	No
Option 3	9,768,688	115,474,000	11.82	No
Option 4	20,111,718	654,217,000	32.53	No
Option 5	1,839,391	38,635,000	21.00	No

10.0 REFERENCES

1. NKRE, "Costing of Produced Water Treatment and Disposal for Platforms in Various Locations," prepared for the Environmental Protection Agency, February, 10, 1983.

2. Hydrotechnic Corporation, "Cost Estimates for Systems to Treat Produced Water Discharges in the Offshore Gas and Oil Industry to Meet BAT and NSPS," prepared for Effluent Guidelines Division, U.S. Environmental Protection Agency, August 27, 1982.

3. Larry Moore, Chevron, New Orleans, personal Communication with Joe Dawley, SAIC, regarding available platform space and platform addition costs. September 19, 1991.

4. Energy Information Agency, "Analysis of Produced Water Treatment Technology Costs," September 12, 1991.

5. Walk, Haydel & Associates, "Estimated Costs of Removal and Disposal of Produced Water Solids from New Facilities - Summary Report No. 7," prepared for American Petroleum Institute, submitted with API comments to the 1985 Proposal, March 14, 1986.

6. ERCE, "The Results of the Sampling of Produced Water Treatment System and Miscellaneous Wastes at the Conoco, Inc. - Maljamar Oil Field," Draft, prepared for Industrial Technology Division, U.S. Environmental Protection Agency, March 1990. (*Offshore Rulemaking Record Volume 115*)

7. Gruy Engineering Corporation, "A Study of the Economic Impacts of Produced Water Effluent Guidelines for the United States Offshore Area," prepared for the Effluent Guidelines Steering Committee of the American Petroleum Institute, November 1990.

8. Letter from Maureen Kaplan, Eastern Research Group, to Joe Dawley, SAIC, "Reconstruction of the logic used by Kohlmann Ruggiero Engineers in estimating the number of dry holes available for reinjection of produced water," June 4, 1992.

9. U.S. Department of Interior, "Comments to the March 13, 1991 Proposal of Offshore Oil and Gas Industry Effluent Guidelines," submitted to the U.S. Environmental Protection Agency, May 13, 1991.

10. Walk, Haydel & Associates, Inc., "Potential Impact of Proposed EPA BAT/NSPS Standards for Produced Water Discharges from Offshore Oil and Gas Extraction Industry," prepared for the Offshore Operators Committee, January 1984.

11. Ron Jordan Correspondence with the MMS regarding Platform Inspections.

12. SAIC, "Estimate of Existing Platforms with Gas Flotation Treatment Systems," prepared for Engineering and Analysis Division, U.S. Environmental Protection Agency, December 1992.

13. ERCE, "Offshore Oil and Gas Industry BAT and NSPS Analysis of Implementation Cost and Contaminant Removal: Produced Water," prepared for USEPA, March 8, 1991.

14. SAIC, "Produced Water Pollutant Variability Factors and Filtration Efficacy Assessments from the Three Facility Oil and Gas Study," prepared for U.S. Environmental Protection Agency, March 1991. (*Offshore Rulemaking Record Volume 120*)

15. SAIC, "Analysis of Oil and Grease Data Associated with Treatment of Produced Water by Gas Flotation Technology," prepared for Engineering and Analysis Division, U.S. Environmental Protection Agency, January 13, 1993.

16. Memorandum from Ronald Jordan, Engineering and Analysis Division, U.S. Environmental Protection Agency, to the Record. "Offshore Oil and Gas - Characterization of BPT- and BAT-Level Produced Water Effluent," December 10, 1992.

SECTION XIII

COMPLIANCE COSTS AND POLLUTANT LOADING DETERMINATION—PRODUCED SAND

1.0 INTRODUCTION

This section presents costs and pollutant reductions for the final proposed regulatory options for produced sand. These technology costs represent additional investment required beyond those costs associated with BPT technologies. The methodology used to determine compliance costs and pollutant loadings for the options considered is based on produced sand generation rate estimates, the characteristics of unwashed and washed produced sand, and onshore disposal at permitted nonhazardous oilfield waste (NOW) facilities and at permitted low level radioactivity disposal facilities.

2.0 PRODUCED SAND GENERATION RATES AND DISPOSAL VOLUMES

The volume of produced sand generated is related to the oil production rate. For this evaluation, EPA used the general rule of thumb that one barrel of produced sand is generated for every two thousand barrels of oil produced.[1] EPA calculated produced sand volumes using peak year oil production estimates obtained from the Minerals Management Service. From industry data, EPA estimated that approximately thirty-four percent (34%) of the produced sand generated offshore is transported to shore for disposal and sixty-six percent (66%) of the produced sand generated offshore is discharged to surface waters.[2] Table XIII-1 presents the total produced sand volumes generated in each offshore region and the volumes of produced sand being discharged into the surface waters and transported to shore for disposal under the BPT no free oil limitations.

3.0 PRODUCED SAND CHARACTERISTICS

The concentrations of oil and grease, moisture content (TSS content), and radioactivity of unwashed and washed sand are based on the Shell Offshore, Inc. sand washing study conducted in 1991.[3] Table XIII-2 presents the characteristics of unwashed and washed produced sand.

TABLE XIII-1

PRODUCED SAND GENERATION VOLUMES AND BPT DISPOSAL PRACTICES

Region	Oil Production Volume (Mbbls)	Produced Sands Volume (bbls)	Offshore Disposal Volume (bbls)	Onshore Disposal Volume (bbls)
Gulf of Mexico	300,000.00	150,000.00	99,000.00	51,000.00
Pacific	150,000.00	75,000.00	51,00.00	24,000.00
Alaska	30,000.00	15,000.00	10,200.00	4,800.00
All Regions	480,000.00	240,000.00	160,200.00	79,800.00

TABLE XIII-2

PRODUCED SAND CHARACTERISTICS

Analyte	Unwashed Produced Sand	Washed Produced Sand
Oil & Grease (wt%)	3.38	1.63
TSS (wt%)	75.1	75.1
Radium 226 (pCi/l)	39	39
Radium 228 (pCi/l)	41	41

4.0 BPT COMPLIANCE COSTS

The costs incurred by the industry to comply with the no discharge of free oil limitation on produced sand consist of two components: onshore disposal cost and sand washing costs. Onshore disposal costs were assigned to the volumes of produced sand currently being transported to shore for treatment and/or disposal (thirty-four percent of the total produced sand generated offshore). Sand washing costs were assigned to the volumes of produced sand currently being discharged to the surface waters. Table XIII-3 presents the BPT compliance costs and the following two sections detail the assumptions used to develop these costs.

TABLE XIII-3

BPT COMPLIANCE COSTS

Region	Onshore Disposal Cost (1986$)	Offshore Compliance Costs (1986$)
Gulf of Mexico	502,860	990,000
Pacific	67,200	102,000
Alaska	274,560	510,000
All Regions	844,620	1,602,000
Total Compliance Costs	2,446,620	

4.1 ONSHORE DISPOSAL COSTS

Transportation costs from the platform to shore were not assigned to the compliance costs because EPA determined that no direct transportation costs would be associated with the zero discharge requirement. EPA's determination is based on data from the Offshore Operators Committee (OOC) produced sand survey and additional information on produced sand handling and disposal practices submitted by the industry.[1] Information from the OOC produced sand survey indicates that produced sand collected regularly through operation of desanders and blowdowns through valves on vessels, accounts for less than ten percent of the volume of sand collected annually. The majority of sand is collected during scheduled cleanouts. The information also indicates that ninety percent (90%) or more of the produced water treatment system cleanouts produce less than 100 barrels of produced sand. The cleanouts occur during a platform shutdown and a typical cleanout cycle is once every three to five years. An operator in the Gulf of Mexico indicated that produced sand is transported to shore by supply boats and dedicated vessels are seldom used to transport produced sand to shore.[4] Based on the available information, EPA concluded that the volume of produced sand collected from vessel blowdowns is small enough that operators are able to use the supply boats that service offshore platforms on a frequent and regular basis, rather than contract for dedicated vessels to transport the waste to shore. The produced sand collected during tank and vessel cleanouts are typically small volumes that can be transported to shore using either the regularly scheduled supply boats or the work boats chartered to support the sand removal or other general maintenance during the platform shutdown.

The disposal costs for the produced sands were the same as for drill cuttings and are as follows: $9.86 per barrel in the Gulf of Mexico; $11.44 per barrel in California (Pacific); and $14.00 per barrel in Alaska (1986 dollars).[5] These costs include transportation from the shore base and disposal at the facility.

4.2 SAND WASHING COSTS

EPA assumed that those operators currently discharging produced sand to the surface waters (66 percent by volume of all produced sand generated offshore) would incur some cost to assure compliance. EPA assigned sand washing costs to all volumes of produced sand discharged offshore to account for an offshore compliance cost.

EPA encountered difficulties in estimating the sand washing costs for produced sand. EPA was unable to obtain firm estimates of sand washing costs from industry operators. EPA did receive sand washing cost estimates of $125 per barrel of produced sand from an equipment vendor.[9,22] Since the estimate of sand washing is substantially higher than EPA and industry estimates of the cost for onshore disposal of produced sand, EPA does not consider the $125 per barrel quote to be representative of the industry-wide cost of sand washing to comply with BPT. In addition, the sand washing estimate provided by the vendor was for a prototype sand washing system under development and was estimated as the cost for a demonstration washing project.

The cost for sand washing can be difficult to estimate, even for the operators. The cost per unit volume of sand can vary significantly as a function of the sand volume washed, difficulties encountered in washing, and the success (or lack of success) in washing the sand. Depending on the volume of sand generated, scheduling constraints, and other economic and logistical considerations, operators choose between: (1) sand washing and discharge on-site; (2) transporting the sand to another platform where the sand from several platforms may be washed and discharged; or (3) onshore disposal to comply with the prohibitions on the discharge of free oil. If sand washing is selected by the operator, it is usually contracted out to offshore service companies. The goal of the sand washing is to reduce the oil content of the produced sand to the extent that the discharge complies with the no free oil limitation. There is, however, no guarantee that sand washing will be successful. If after washing the produced sand is still unable to comply with the no free oil limit, onshore disposal is usually necessary (and therefore incurring both washing and onshore disposal costs). Also, according to data submitted by the industry, the sand washing process generates wastes (washing liquids and a portion of the solids) which are unable to meet the no free oil limit. These wastes are typically disposed of onshore.[3]

For the purpose of conducting the BCT cost reasonableness test, and based on the information discussed above and the frequency at which produced sand is currently disposed of onshore as an alternative to sand washing, EPA estimated the cost of sand washing to be comparable to the cost of onshore disposal. The average industry-wide BPT cost of sand washing is estimated at $10 per barrel of produced sand. Using this cost and the offshore disposal volumes listed in Table XIII-1, the total industry-wide costs for washing produced sand for each of the three major production regions in the U.S. were determined. Considering that day rates for offshore service vessels are approximately $3,000 per day and that produced sand volumes are typically less than 100 barrels each, it would be difficult for operators to achieve significantly lower sand washing costs even if the produced sand from several platforms are combined. Using a higher per barrel sand washing cost for BPT (as would be suggested by the equipment vendor estimate discussed above) provides a lower value in the BCT industry cost test and would make the BCT zero discharge limitation more cost reasonable.

5.0 BPT POLLUTANT REMOVALS

The technology basis for BPT compliance of no free oil is sand washing to remove the free oil and onshore disposal. The BPT pollutant removals are based on two components: the reduction of oil and grease due to sand washing and the reduction of TSS, and oil and grease. Some estimates were also made for removals of radionuclides due to onshore disposal. However, these estimates are only based on limited information contained in the Shell Offshore, Inc. sand washing study.[3]

Oil and grease reductions due to sand washing are based on an average oil and grease concentration of 3.38 percent by weight in untreated produced sand and 1.63 percent by weight in washed sand. The BPT reductions in oil and grease due to washing (to prevent free oil) are 1.75 percent by weight oil and grease.

The BPT reductions from onshore disposal of produced sand are based on the sand containing 3.38 percent by weight oil and grease (concentration in unwashed sand). The TSS reductions are based on the fact that the moisture content of produced sand brought to shore for disposal is 24.9 percent by weight (or 75.1 percent by weight of the total produced sand is TSS). The reductions in the discharges of radionuclides are based on average concentrations of Radium-226 and Radium-228 in produced sand.

The average concentrations of Radium-226 and Radium-228 in produced sand are calculated to be 39 picocuries per gram of Radium-226 and 41 picocuries per gram of Radium-228. Table XIII-4 presents the pollutant removals due to BPT compliance for produced sand.

TABLE XIII-4

BPT POLLUTANT REDUCTIONS

	Reductions due to Onshore Disposal	Reductions due to Sand Washing
Oil and Grease (lbs)	2,834,368	2,946,030
Total Suspended Solids (lbs)	62,976,631	0
Conventionals (lbs)	65,810,999	2,946,030
Total Conventional (lbs)	68,757,029	
Radium 226 (microcuries)	950,055	
Radium 228 (microcuries)	998,776	

6.0. BCT, BAT AND NSPS OPTIONS CONSIDERED

There were two options considered for this waste stream: (1) establish the requirement equal to the current NPDES permit limitations prohibiting discharge of free oil; or (2) prohibit discharge of produced sand, technologically based on transporting to shore for treatment and/or disposal. The technology basis for the option limiting free oil content is a water or solvent wash of produced sands prior to discharge. For the option of no discharge of free oil, the method of determining compliance with the free oil prohibition is the static sheen test. The prohibition on the discharge of free oil (as an indicator of toxic pollutants) or the zero discharge requirement for produced sand would reduce or eliminate the discharge of conventional and toxic pollutants to surface waters. Since the BPT limitations prohibit the discharge of free oil, EPA determined that the industry would incur no additional costs from the BCT, BAT, and NSPS limitations on free oil (Option 1). The incremental costs and the pollutant removals for the zero discharge option (Option 2) are presented in the following sections.

7.0 ZERO DISCHARGE COMPLIANCE COSTS

In calculating onshore disposal costs of produced sand from production operations in the Gulf of Mexico, EPA assigned separate costs for the disposal of produced sand at non-hazardous oil field waste facilities (NOW facilities) and at low level radioactivity disposal facilities. Data from the OOC produced sand survey indicate that 25 percent of the production facilities located in the Gulf of Mexico generate produced sand with radioactivity levels above regulatory concern. Produced sand with NORM levels above 50 microroentgens per hour or 30 picocuries per gram were assumed to be disposed of in low level radioactive waste facilities because MMM's Letter to Lessee requires this sand to be transported to shore for disposal. The available data from production operations offshore Alaska and California indicate that produced sands from these operations do not have NORM above these levels. Because of pending state guidelines potentially banning the disposal of NORM contaminated sand at NOW facilities, EPA assigned costs for disposing the produced sand at a low level radioactivity disposal facility for 25 percent of the volume of produced sand brought to shore under the zero discharge requirement. Based on disposal information from a Superfund cleanup project transporting and disposing of low level radioactive solids, EPA estimated that transportation costs would be $200 per cubic yard. Transportation would be in a closed gondola railcar. The disposal costs were estimated to be $135 (1986 dollars) per cubic yard at a NORM facility in Utah. The total transportation and disposal cost at the NORM facility was calculated to be $69.64 per barrel (1986$).[6] The NORM disposal facility is located on a 540-acre site and is currently in the phase 1 cell of a three phase cell program. Each cell has a capacity of 3 million cubic yards and all cells are permitted by the State of Utah. In 1992 the facility accepted approximately 200,000 yards of NORM and mixed wastes. After 3 years of operation the first cell is at 20 percent capacity.[7]

Produced sands generated offshore Alaska, California, and the Gulf of Mexico not considered to contain NORM were assigned costs for disposal at NOW facilities under the zero discharge requirement. These costs are the same as those presented in Section XIII.4.1. Table XIII-5 presents the regional and total costs for the zero discharge option.

TABLE XIII-5

ZERO DISCHARGE DISPOSAL COSTS

Region	Disposal at E&P Facility Volume (bbls)	Disposal at NORM Facility Volume (bbls)	E&P Facility Disposal Costs ($)	NORM Facility Disposal Costs ($)
Gulf of Mexico	112,500	37,500	1,109,250	2,611,500
Pacific	75,000	0	858,000	0
Alaska	15,000	0	210,000	0
All Regions	202,500	37,500	2,177,250	2,611,500
		Total Disposal Costs:		4,788,750

8.0 ZERO DISCHARGE POLLUTANT REMOVALS

The technology basis for the BCT, BAT and NSPS zero discharge option for produced sand is onshore disposal. Oil and grease reductions are based on the assumption that the cleaned produced sand will no longer be discharged to the surface waters. Thus a net reduction of 1.63 percent oil and grease is achieved through the zero discharge limitation. The reductions in TSS are based on the moisture content of produced sand (24.9 percent) and thus a net reduction in TSS of 75.1 percent of the volume currently discharged is achieved through the zero discharge requirement. The reductions in the discharges of radionuclides into the surface waters are based on average concentrations of Radium-226 and Radium-228 in produced sand. Table XIII-6 presents the BCT, BAT and NSPS pollutant removals for oil and grease, TSS, and radionuclides.

TABLE XIII-6

BCT/BAT/NSPS POLLUTANT REDUCTIONS

Pollutant Parameter	Removals due to Zero Discharge
Oil and Grease (lbs)	8,524,414
Total Suspended Solids (lbs)	189,403,402
Total Conventional (lbs)	197,927,816
Radium 226 (microcuries)	2,790,000*
Radium 228 (microcuries)	2,940,000*

*Radium removals are estimated based on rough extrapolation of data included in OOC Produced Sand Survey.

9.0 BCT/BAT/NSPS INCREMENTAL COSTS AND POLLUTANT REMOVALS

The incremental compliance costs and pollutant removals due to zero discharge of produced sand are calculated by subtracting the BCT/BAT/NSPS costs and removals from the BPT costs and removals. Table XIII-7 presents the incremental compliance costs and pollutant removals for the zero discharge option.

TABLE XIII-7

ZERO DISCHARGE INCREMENTAL COMPLIANCE COSTS AND POLLUTANT REMOVALS

Pollutant Parameter	Removals due to Zero Discharge
Oil and Grease (lbs)	2,744,016
Total Suspended Solids (lbs)	126,426,771
Total Conventional (lbs)	129,170,787
Radium 226 (microcuries)	1,839,945*
Radium 228 (microcuries)	1,941,224*
Incremental Compliance Costs (1986$)	2,342,130

*Radium removals are estimated based on rough extrapolation of data included in OOC Produced Sand Survey.

10.0 BCT COST TEST

Since there are no incremental costs due to the no free oil limitation, Option 1 was assumed to pass the BCT cost test. This section presents the results of the BCT cost test for the zero discharge option. The methodology for the BCT cost test is presented in Section XI.7.0.

The BPT limitations on produced sand of no free oil result in a reduction of 68,757,029 pounds per year of conventional pollutants at a cost of $2,446,620 per year (1986 dollars). Dividing the cost by pollutant removal, the BPT cost per pound of conventional pollutants removed for produced sand is $0.0355 per pound (1986 dollars). The calculation is as follows:

$$\text{BPT Cost Ratio} = \frac{\$2,446,620}{68,757,029\text{ lbs.}} = \$0.0355$$

The POTW cost test represents the cost per pound of BCT level of control incremental to BPT, or the ratio of incremental cost to incremental pollutant removal. The POTW rate is calculated as follows:

$$\text{POTW Cost Test Ratio} = \frac{\$2,342,130}{129,170,787\text{ lbs.}} = \$0.01813$$

The industry cost ratio (ICR) represents the ratio of achieving BCT level of control incremental to BPT versus achieving BPT level of control to the raw waste load, or the POTW ratio divided by the BPT ratio. The ICR calculation is as follows:

$$ICR = \frac{\text{POTW Ratio}}{\text{BPT Cost Ratio}} = \frac{0.0181}{0.0355} = 0.5099$$

The results of the BCT cost reasonableness test for the zero discharge option are presented in Table XIII-8.

TABLE XIII-8

BCT COST TEST PRODUCED SAND

BCT Option	Incremental Conventional Pollutants Removed (lb/yr)	Incremental Compliance Cost ($/year)	POTW Cost/ Ratio ($/lb)	Pass	ICR Ratio	Pass
Zero Discharge	129,170,787	2,342,130	0.0181	Y	0.5099	Y

Since the ICR test result is less than 1.29, the result passes the industry cost-effectiveness test. The zero discharge option for produced sand is found to be cost-reasonable since the option passed both tests.

11.0 REFERENCES

1. James P. Ray, "Offshore Discharges of Drill Cuttings," Outer Continental Shelf Frontier Technology, Proceedings of a Symposium, National Academy of Sciences, December 6, 1979. (*Offshore Rulemaking Record Volume 18*)

2. Offshore Operators Committee. "Response to EPA Request for Additional Information," letter from J.F. Branch, Chairman Offshore Operators Committee, to Ronald P. Jordan, Engineering and Analysis Division, U.S. Environmental Protection Agency. August 30, 1991.

3. Letter from R.J. Vallejo, Shell Offshore Inc. to D.J. Bourgeois, Minerals Management Service. "Produced Sand Discharge Monitoring Study Interim Data Submittal." June 11, 1991. (*Offshore Rulemaking Record Volume 147*)

4. Andrew Parker, Marathon Oil Co., Lafayette, LA., personal communication with Joe Dawley, SAIC, regarding produced sand washing and disposal costs. September 16, 1992.

5. Walk, Haydel & Associates, Inc., "Water-Based Drilling Fluids and Cuttings Disposal Study Update," January 1989. *Submitted as comments to 53 FR 41356 by the American Petroleum Institute, January 18, 1989. (Offshore Rulemaking Record Volume 94)*

6. New Jersey Department of Environmental Protection, "Briefing to the U.S. Department of Energy on the use of the Envirocare of Utah Facility for Disposal of Wastes from the Formerly Utilized Sites Remedial Action Program Sites in New Jersey," September 14, 1989.

7. Kurt Higgins, Envirocare of Utah, personal communication with Joe Dawley, SAIC, regarding capacity at Envirocare NORM facility. January 12, 1993.

SECTION XIV

COMPLIANCE COST AND POLLUTANT LOADING DETERMINATION—WELL TREATMENT, WORKOVER, AND COMPLETION FLUIDS

1.0 INTRODUCTION

This section presents the compliance costs for the final regulatory options for treatment and disposal of well treatment, workover, and completion fluids.

2.0 COMPLIANCE COSTS AND POLLUTANT REMOVAL CALCULATION METHODOLOGY

The compliance costs for the BCT, BAT and NSPS treatment options for well treatment, workover, and completion (TWC) fluids are based on volumes of TWC fluids generated and the size of the production platform where the fluids are being generated. Pollutant removals associated with the treatment options were not calculated because there is insufficient data on the chemical characteristics of well treatment, workover, and completion fluids and the fact that since these fluids vary from well to well, a generalized characterization of TWC fluids would be inadequate.

3.0 WELL TREATMENT, WORKOVER, AND COMPLETION FLUIDS GENERATION RATES

The average volume of workover and completion fluids generated is 300 barrels per well. This volume accounts for a preflush and postflushing of the well and weighting fluid for a 10,000 foot well. According to industry comments and literature, workover and completion fluids are typically reused at least once, so if the same workover or completion is used for two wells, the fluid generated per well is reduced to 150 barrels. The average volume of treatment fluids generated is 250 barrels per well and treatment fluids are typically spent at the end of the job, and thus are not reused. Well workovers or treatment jobs were reported to occur approximately every four years. Well completions are a function of the number of development wells drilled.[1]

For the purpose of estimating the volumes of well treatment, workover, and completion fluids generated, EPA projected the occurrences of well treatments, workovers, and completions over a fifteen year period. Yearly volumes were calculated based on the yearly average of the total volumes generated over the fifteen year period.

4.0 BCT REGULATORY OPTIONS

The BCT limitations for the final rule prohibit the discharge of free oil. Compliance with this limitation is determined by the static sheen test. Because of a lack of sufficient data regarding the levels of conventional pollutants present in both treated and untreated well treatment, workover, and completion fluids, EPA only considered the BCT option as being equal to BPT. There are no costs or non-water quality environmental impacts associated with this BCT limitation.

5.0 BAT AND NSPS OPTIONS CONSIDERED

Well treatment, workover, and completion fluids may either stay in the hole, resurface as a concentrated volume (slug), or surface from the well dispersed with the produced water. Two options were considered for BAT and NSPS control for this waste stream: (1) establish the requirements equal to the current BPT limit of no discharge of free oil (with compliance determined by the static sheen test); or (2) meet the same limitations on oil and grease content as produced water.

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

The prohibition on the discharge of free oil and cotreatment 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 is the static sheen test. For the no free oil limitation, EPA determined that there would be no incremental compliance costs. The incremental costs and pollutant removals for option 2 are discussed in Sections XIV.5. Pollutant removals are not calculated for option 2 because of the difficulty in characterizing this wastestream.

6.0 INCREMENTAL COST CALCULATIONS

Option 2 requires well treatment, workover, and completion fluids to meet the oil and grease limitations of produced water based on the technology of cotreating these fluids with the produced water treatment system. Treating these fluids with produced water is considered to incur no, or minimal, additional compliance costs. Costs to properly operate the produced water treatment system and monitor for compliance are accounted for in the compliance cost projections for produced water. However, some facilities may be unable to treat well treatment, workover, and completion fluids with the produced water and would incur compliance costs under this option. The following paragraphs discuss the costing methodology for those facilities.

Some facilities may not be able to commingle TWC fluids with the produced water stream for treatment because of the relative volume of produced water generated and/or the size of the produced water treatment system. In this case, the introduction of the TWC fluids to the produced water treatment system may dramatically affect the separation efficiency of the treatment system resulting in non-compliance with the NPDES permit and subsequent fines. A 1989 industry report stated that facilities with less than ten producing wells would most likely experience produced water treatment system upsets due to commingling of TWC fluids with the produced water stream for treatment. The report stated that facilities with greater than ten wells will have large enough treatment systems to provide sufficient dilution of the TWC fluids such that upsets will not occur. To account for the technical limitations of commingling TWC fluids, EPA developed compliance costs based on the technology of capturing and transporting the wastes to shore for treatment and/or disposal for facilities with fewer than ten well slots. The only platforms with fewer than ten well slots are located in the Gulf of Mexico. In the EPA's production profiles, these facilities are the model platforms Gulf 1a, 1b, 4, and 6. Onshore disposal costs for TWC fluids were developed for the Gulf 1a, 1b, 4, and 6 facilities currently discharging offshore, which is 67 percent since 37 percent of all structures in the Gulf are currently piping produced water to shore for treatment.[1]

6.1 VOLUMES GENERATED FROM EXISTING STRUCTURES

To calculate the volumes of well treatment and workover fluids generated from existing facilities (completions are considered new sources), EPA assumed that a well treatment or workover job would occur every four years. EPA also estimated the average volume generated from either a well treatment or workover job as being 200 barrels a job (This is the arithmetic average of typical volume generated from a well treatment, which is 250 barrels, and from a workover, which is 150 barrels). EPA developed a yearly well treatment/workover volume by dividing the average volume generated by four. The total volumes of well treatment and workover fluids generated were calculated by multiplying the average yearly volume by the total number of wells. Table XIV-1 presents the volumes of well treatment and workover fluids generated from the existing Gulf 1a, 1b, 4, and 6 model platforms.

TABLE XIV-1

TOTAL BAT WORKOVER AND TREATMENT VOLUME GENERATION ESTIMATES

Structure Type:	Total Structures Discharging Offshore	Number of Wells per Structure	Total Number of Producing Wells	Volume of Workover/Treatment Fluids Generated (barrels per year)	Onshore Reinjection Costs ($/yr)
Oil Facilities:					
Gulf 1a	89.55	2	89.55	4,477.5	53,730
Gulf 1b	13.23	2	13.23	661.5	7,938
Gulf 4	27.72	8	110.88	5,544	66,528
Gulf 6	11.97	12	71.82	3,591	43,092
Oil and Gas:					
Gulf 1a	139.86	2	139.86	6,993	83,916
Gulf 1b	61.74	2	61.74	3,087	37,044
Gulf 4	75.6	8	302.4	15,120	181,440
Gulf 6	80.01	12	480.06	24,003	288,036
Gas:					
Gulf 1a	332.01	2	332.01	16,600.5	199,206
Gulf 1b	170.1	2	170.1	8,505	102,060
Gulf 4	110.88	8	443.52	22,176	266,112
Gulf 6	100.8	12	604.8	30,240	362,880
Total:	1,213.47		2,819.97	140,998.5	1,691,982

6.2 VOLUMES GENERATED FROM NEW STRUCTURES

The constrained scenario drilling profiles were used to calculate the volumes of completion fluids generated from new sources. EPA identified the projected number of new wells drilled associated with the Gulf 1b, 4, and 6 model platforms. EPA determined that 1754 wells would be drilled under the constrained scenario from the Gulf 1b, 4, and 6 model platforms over the 15 year period following promulgation of this rule. For a more detailed discussion on the *constrained scenario refer to the Economic Impact Analysis* for this rule. A yearly average of wells drilled was calculated to determine the yearly number of completions and the yearly volume of completion fluids generated. The average number of wells drilled per year from a Gulf 1b, 4, and 6 model platform is 115.

The number of well treatment and workover jobs for new source wells was determined based on the fact that a well treatment or workover is done every four years and that 115 new wells are drilled per year. In the first four years of the fifteen year period, no treatment or completion jobs are done but in the fifth year 115 treatment or completion jobs are performed and in the subsequent years more treatment or workover jobs are performed as the population of existing wells increases. The average well treatment/workover fluid volume was used to determine the total treatment/workover fluid volumes generated from new sources.

Table XIV-2 presents the volumes of well treatment, completion, and workover fluids generated from new source Gulf 1b, 4, and 6 model platforms.

TABLE XIV-2

NSPS WORKOVER AND COMPLETION SCHEDULE, VOLUME ESTIMATES, DISPOSAL COSTS

Year	Number of Wells Drilled Per Year	Number of Workover/ Treatment Jobs Done Per Year	Number of Completion Jobs Done Per Year	Volumes of Workover/Treatment Fluids Generated (barrels per year)	Volumes of Completion Fluids Generated (barrels per year)	Workover/ Treatment Injection Costs ($ per year)	Completion Injection Costs ($ per year)	Total Onshore Injection Costs ($ per year)
1	115	0	115	0	17,250	0	207,000	207,000
2	115	0	115	0	17,250	0	207,000	207,000
3	115	0	115	0	17,250	0	207,000	207,000
4	115	0	115	0	17,250	0	207,000	207,000
5	115	115	115	23,000	17,250	276,000	207,000	483,000
6	115	115	115	23,000	17,250	276,000	207,000	483,000
7	115	115	115	23,000	17,250	276,000	207,000	483,000
8	115	115	115	23,000	17,250	276,000	207,000	483,000
9	115	230	115	46,000	17,250	552,000	207,000	759,000
10	115	230	115	46,000	17,250	552,000	207,000	759,000
11	115	230	115	46,000	17,250	552,000	207,000	759,000
12	115	230	115	46,000	17,250	552,000	207,000	759,000
13	115	345	115	69,000	17,250	828,000	207,000	1,035,000
14	115	345	115	69,000	17,250	828,000	207,000	1,035,000
15	115	345	115	69,000	17,250	828,000	207,000	1,035,000
Totals:	1,725	2,415	1,725	483,000	258,750	5,796,000	3,105,000	8,901,000
Average workover/treatment costs over 15 year period: 386,400 dollars per year								

6.3 STORAGE COSTS

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

6.4 TRANSPORTATION COSTS

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

6.5 ONSHORE DISPOSAL COSTS

EPA determined the most common method of onshore treatment of spent fluids to be injection into underground formations at a centralized treatment facility. The disposal costs are estimated to be $12 per barrel. This cost includes the costs of transporting the fluids from an inland port transfer station to the disposal facility, solids removal if necessary, and reinjection.

6.6 BAT AND NSPS VOLUMES AND DISPOSAL COSTS

Table XIV-1 presents the BAT workover and treatment volume generation estimates and onshore disposal costs. Volume estimates and disposal costs for completion fluids are not included in the BAT costs because completion fluids are considered wastes from new sources and hence are only assigned to the NSPS costs.

Table XIV-2 presents the yearly NSPS workover, treatment, and completion generation volumes and disposal costs for the fifteen years following promulgation of this rule. Table XIV-2 also presents the average yearly workover and treatment fluid disposal costs for the 15 year period.

7.0 REFERENCES

1. Memorandum from Allison Wiedeman, Project Officer to Marv Rubin, Branch Chief. "Supplementary Information to the 1991 Rulemaking on Treatment/ Workover/Completion Fluids," December 10, 1992.

SECTION XV

BASIS FOR REGULATION - DECK DRAINAGE

1.0 BCT, BAT AND NSPS OPTIONS CONSIDERED

EPA has selected the option requiring no discharge of free oil for BCT, BAT and NSPS control of deck drainage. Because of the difficulties in obtaining a representative sample of this wastestream for conducting the static sheen test since the effluent is located in an inaccessible location, compliance with this limitation is determined by the visual sheen test. Deck drainage is typically collected in a sump tank where initial oil/water separation takes place. Water discharged from the sump tank is usually directed to a skim pile, where additional oil/water separation occurs. The separation process in the skim pile typically occurs beneath the ocean surface, and the separated water is discharged to the ocean from the bottom of the skim pile. (The skim pile is essentially a bottomless pipe with internal baffles to collect the separated oil.) The difficulties in obtaining a representative sample of skim pile effluent preclude the use of the static sheen test for this wastestream. (The operation of a skim pile is discussed in more detail in the Development Document.)

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

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

Since BCT, BAT, and NSPS are being set equal to the current BPT, there are no costs or non-water quality environmental impacts associated with this limitation and it is available and economically achievable. The BCT limitation of no discharge of free oil is also considered to be cost reasonable under the BCT cost test. Since the POTW test result pressure scenario, the peak year required 2,800 gallons of diesel fuel and emitted 2.8 tons of air pollutants, decreasing to 1,000 gallons of diesel fuel and 1.0 ton of air emissions in year 15. For the low pressure scenario, 700 gallons of diesel fuel were required and 1 ton of air pollutants emitted in the first year after promulgation, decreasing to 250 gallons of diesel fuel and 0.4 tons of air emissions in year 15.

SECTION XVI

BASIS FOR REGULATION - DOMESTIC WASTE

1.0 BCT, BAT, AND NSPS OPTIONS CONSIDERED

Under BCT and NSPS, EPA is prohibiting the discharge of all floating solids, and incorporating limits on garbage as currently required at 33 CFR Part 151. Discharges of garbage, including plastics, are already prohibited at 33 CFR Part 151, which implements Annex V of the Convention to Prevent Pollution from Ships (MARPOL) and the Act to Prevent Pollution from Ships, 33, U.S.C. 1901 et seq. Discharges of foam are also prohibited under BAT and NSPS. (The subject of the referenced regulations is the disposal of garbage generated during the normal operation of ships. One category of ships includes fixed and floating platforms "engaged in the exploration, exploitation and associated offshore processing of seabed mineral resources." One category of garbage is plastic.) [The definition of "garbage" is included in 33 CFR 151.05.]

The limitations established for BCT, BAT, and NSPS are all technologically available and economically achievable because they are either currently required in Coast Guard regulations or are required in current NPDES permits. Under the Coast Guard regulations, discharges of garbage, including plastics, from fixed and floating platforms engaged in the exploration, exploitation and associated offshore processing of seabed mineral resources are prohibited with one exception. Victual waste (not including plastics) may be discharged from fixed or floating platforms located beyond 12 nautical miles from nearest land, if such waste is passed through a comminuter or grinder meeting the requirements of 33 CFR 151.75. Section 151.75 requires that the grinders or comminuters must be capable of processing garbage so that is passes through a screen with openings no greater than 25 millimeters (approximately 1 inch) in diameter. A permit promulgated by Region VI for the Western Gulf of Mexico OCS incorporates the Coast Guard regulations (57 *FR* 54642; November 19, 1992). Discharge of foam in other than trace amounts is included in this Region VI permit and the 1986 general permit for the Gulf of Mexico OCS as a mechanism for controlling detergents (51 *FR* 24922). A similar prohibition on discharge of visible foam in other than trace amounts was proposed in the proposed reissuance of the general permit for the Gulf of Mexico in 1991, (56 *FR* 15359).

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

SECTION XVII

BASIS FOR REGULATION—SANITARY WASTE

1.0 BCT, BAT, AND NSPS OPTIONS CONSIDERED

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

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

Since there are no increased control requirements beyond that already required by BPT effluent guidelines, there are not incremental compliance costs or non-water quality environmental impacts associated with BCT and NSPS limitations for sanitary wastes. Since these limitations are equal to BPT, they are available and economically achievable. In addition, the BCT limitation is also considered to be cost reasonable under the BCT cost test. Since the POTW test result and the industry cost-effectiveness test results are both zero (and therefore pass their respective tests), the limitation is cost reasonable.

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

SECTION XVIII

NON-WATER QUALITY ENVIRONMENTAL IMPACTS AND OTHER FACTORS

1.0 INTRODUCTION

The elimination or reduction of one form of pollution has the potential to aggravate other environmental problems, an effect frequently referred to as cross-media impacts. Under sections 304(b) and 306 of the Clean Water Act, EPA is required to consider these non-water quality environmental impacts (including energy requirements) in developing effluent limitations guidelines and new source performance standards. In compliance with these provisions, EPA has evaluated the effect of these regulations on air pollution, solid waste generation and management, consumptive water use, and energy consumption.

This section discusses the non-water quality environmental impacts associated with the final regulations for each waste stream, and other factors such as safety and administrative burden.

2.0 DRILLING WASTES

The technology basis for the limitations on drilling fluids and drill cuttings is transportation of these wastes to shore for treatment and/or disposal. Therefore, adequate onshore disposal capacity for these wastes is critical in assessing the options. Safety, impacts of marine traffic on coastal waterways, and implementation considerations such as administrative burden and enforcement were other factors also considered.

EPA evaluated the non-water quality environmental impacts on a regional basis because the different regions each have their own unique considerations (e.g., air emissions are a particular concern in southern California, while availability of disposal sites is more limiting for the Gulf of Mexico). Although not specifically detailed in the discussion below, the non-water quality environmental impacts associated with any potential drilling and production activities in regions other than the Gulf of Mexico, California, and Alaska have been considered acceptable.

2.1 ENERGY REQUIREMENTS AND AIR EMISSIONS

The control technology basis for compliance with the options considered for the drilling fluids and drill cuttings waste streams is a combination of product substitution and/or transportation of drilling wastes to shore for treatment and/or disposal. EPA estimated air emissions resulting from the operation of boats, cranes, trucks, and earth-moving equipment by using emission factors relating the production of air pollutants to time of equipment operation and amount of fuel consumed. The differential increase in fuel requirements and air emissions associated with the control options in the final rule are presented in Table XVIII-1.[1] Nitrogen oxides (NO_x) emissions from exploratory drilling activities are estimated at 78 tons/operation. For comparison, the increase in air emissions due to offshore activities related to onshore disposal of drilling wastes is estimated at approximately 1.5 tons of NO_x (less than 2%) for each well subject to the zero discharge limitations.

TABLE XVIII-1

AIR EMISSIONS AND ENERGY REQUIREMENTS FOR DISPOSAL DRILLING FLUIDS AND DRILL CUTTINGS

Options	Volume of Barged Waste (bbl/yr)	Air Emissions (tons/yr)	Fuel Requirements (BOE/yr)
3 Mile Gulf/CA	691,000	298	34,900
8 Mile Gulf/ 3 Mile CA	1,374,000	466	55,700
Zero Discharge Gulf and CA	6,811,000	1,798	221,400

2.1.1 Energy Requirements

Energy requirements for each of the treatment options considered for the final rule were calculated by identifying those activities necessary to support onshore disposal of drilling wastes. Those activities requiring fuel consumption include:

- Supply boats to transport the drilling wastes
- Crane operation at the drilling sites and marine transfer stations to facilitate off-loading the wastes
- Trucks to transport the wastes from the marine transfer station to the onshore disposal site

- Earth-moving equipment at the disposal site to facilitate land spreading and landfill operations.

The following sections present the assumptions and the methodology used to estimate the energy required by the various transportation and handling activities associated with onshore disposal of offshore-generated drilling fluids and drill cuttings.[1]

2.1.1.1 Supply Boats

The fuel usage due to operation of supply boats to transport drilling waste to shore accounts for the highest percentage of fuel used in onshore disposal. Supply boat energy requirements were calculated by estimating the fuel consumption from each of the aspects associated with transporting drilling waste to shore, including:

- Transit fuel consumption
- Maneuvering fuel consumption
- Idling fuel consumption
- Auxiliary electrical generation
- Supply boat capacity and usage.

This section details the assumptions made to estimate the fuel usage for each of these activities.

- Transit Fuel Consumption: The supply boat horsepower rating, operating efficiency, transit speed, and average transit distance are as follows:

  - Power Rating: 2,500 horsepower diesel powered engine.[2]

  - Fuel Consumption: 110 gallons of diesel per hour.[2] The supply boat operates at 65 percent of the rated horsepower during open water transit Extrapolating from 110 gal per hour at 65 percent power, the full throttle fuel consumption rate is estimated at 169 gallons per hour.[3]

  - Boat Speed: The average boat speed during transit is 10 knots.[2]

  - Average Distance: The average round trip distance is 100 miles.[4]

- Maneuvering Fuel Consumption: Supply boats are estimated to maneuver at the platform for an average of one hour per visit to the drill site. The maneuvering fuel use factor is 15 percent of full throttle fuel consumption.[3]

- Idling Fuel Consumption: Due to ocean current and wave action, boats must maintain engines idling while at the drill site unloading empty cuttings boxes and loading drilling fluids and boxes. The average time idling on station at the drill site is 4 hours per visit. This is based on the crane operating time of 2.4 hours to transfer empty cuttings boxes to the rig or platform and loading the full cuttings boxes onto the supply boat. The average idling time includes an additional 1.6 hours to account for potential delays in the transfer process.

- Auxiliary Electrical Generator: The usage of an auxiliary generator is needed for electrical power only when propulsion engines are shutdown. Since the supply boats remain at the drill site only for the length of time necessary to conduct loading/unloading evolutions and propulsion plant remains idling at the drill site, the auxiliary generator is only used while inport.

  The average inport time for unloading drilling fluids and drill cuttings, tank cleanout, and demurrage is 24 hours per supply boat trip.[2] The boat engines would be shutdown during this period. EPA assumed that while inport, the boat operator will rely on the auxiliary generator for electrical power.

  For the purposes of estimating fuel requirements and air emissions, EPA assumed that the auxiliary generator is rated at 120 HP, operates at 50 percent load[3] and consumes 6 gallons of diesel fuel per hour.[2]

- Supply Boat Capacity and Usage: An offshore supply boat typically measures 160 to 180 feet long and can store approximately 12 to 18 cuttings boxes (25 barrel) on deck and 2,500 barrels of drilling fluids in tanks below deck. Dedicated supply boats typically carry 16 cuttings boxes while regularly-scheduled supply boats typically carry 10 cuttings boxes. For the purposes of estimating fuel requirements and air emissions, EPA used an average supply boat (dedicated and regularly scheduled) capacity of 12 boxes.

  EPA assumed that dedicated supply boats are necessary during the first phase of drilling the well, approximately the first 4,500 linear feet, to prevent stoppage of drilling due to lack of storage space. The drilling platform or rig has sufficient available deck area to store 12 cuttings boxes and 500 barrels of excess drilling fluids without affecting drilling operations.[5] The cuttings generation rate is the highest during the first 4,500 feet of drilling due to the large diameter borehole diameter and the volume of drill cuttings are the limiting factor for boat capacity. Between 4,500 feet and final well-depth, the drill cuttings generation rate subsides as the borehole diameter decreases and the drilling fluids generation rate is low enough that there is sufficient capacity on the platform/rig deck to store the drilling waste and that the regularly-scheduled supply boats have sufficient capacity to transport the accumulated volumes of drilling fluids and drill cuttings. Regularly-scheduled supply boats service the drilling site once every two days. At the final well-depth an additional dedicated supply boat is required because there is a large volume of drilling fluids from cleaning out the well casing and mud tanks which require onshore disposal. At final well-depth the volume of drilling fluids requiring disposal are the limiting factor since there may be more than 2,500 barrels (the liquid storage capacity of a supply boat).

  EPA estimated that 6 dedicated boat trips would be required for drilling operations in the Gulf of Mexico and offshore of Alaska. This consists of 5 boats trips to haul cuttings during the first 4,500 linear feet of drilling and one dedicated boat trip to transport the drilling fluid at final well-depth. For drilling projects offshore of California, EPA estimated 5 dedicated boat trips; 4 to haul cuttings from the initial drilling phase and 1 dedicated boat trip to haul drilling fluid at final well-depth.[1]

2.1.1.2 Cranes

Cranes used to load and offload cuttings boxes at the drill site and inport are diesel powered and contribute to additional fuel requirements and air emissions. The assumptions used to estimate the fuel usage and air emissions from crane operation are as follows:

- Power Rating: 170 horsepower operating at 80 percent of rated load.[3]
- Fuel Consumption: 67 gallons of diesel fuel per hour.[2]
- Lift Capacity: 10 lifts per hour.[2] The unloading of 12 empty cuttings boxes and loading 12 full cuttings boxes on the supply boat requires a minimum of 2.4 hours.

2.1.1.3 Trucks

Since many disposal sites are either located at marine transfer stations, or transfer wastes at the marine transfer stations from supply vessels to barges and then use the waterways to carry the drilling wastes to the drilling sites, much of the drilling waste may not actually require truck transportation. However, the fuel requirements and air emissions attributed to truck usage in EPA's own analysis are considered to approximate the energy requirements and air emissions resulting from the alternative use of barge traffic. The number of truck trips, in conjunction with the distance travelled between the marine transfer station and the disposal site is the basis in estimating the fuel usage. The following assumptions were used in developing fuel requirements and air emissions resulting from onshore transportation of drilling wastes:

- Truck Capacity: 5,000 gallons (119 barrels) of drilling fluids and drill cuttings.[2]
- Fuel Consumption: 4 miles per gallon of diesel fuel.[2]
- Distance: The average round trip distance between the marine transfer station (port facilities) and the final treatment and disposal site (landfill/landfarm) is estimated at 100 miles. For Alaska, an average round trip of 1,600 miles is used.

2.1.1.4 Land Disposal Equipment

The use of land-spreading equipment at the disposal site was based on the drilling waste volumes and the projected capacity of the equipment. The following assumptions were made in developing fuel requirements and air emissions resulting from onshore treatment of drill waste:

- Wheel Tractor: Wheel tractors are used at the facility for grading. It is estimated that 8 hours of tractor operation is required to grade the drilling waste volume from one well. The estimated fuel consumption rate for a wheel tractor is 1.67 gallons of diesel fuel per hour.[2]

- Track-Type Dozer/Loader: A track-type dozer is required at the facility for wastespreading. EPA estimated that 16 hours of dozer operation are required to spread the drilling wastes generated from one well. The estimated fuel consumption rate for a dozer is 22 gallons of diesel fuel per hour.[2]

2.1.2 Air Emissions

Emission factors were determined for both controlled and uncontrolled sources. The term "uncontrolled refers to the emissions resulting from a source which does not utilize add-on control technologies or methodologies to reduce the emissions of specific pollutants. "Controlled" emission factors are developed for the case in which the source of emissions has implemented some means of control to reduce emissions of specific pollutants. "Controlled" emission factors are developed for the case in which the source of emissions has implemented some means of control to reduce specific emissions. In the case of sulfur dioxide (SO_2), the use of low-sulfur fuel results in reduced SO_2 emissions. The control method for nitrogen oxides (NO_x) was based on retarding the injection timing of engines. Injection timing retard is estimated to reduce NO_x emissions by 20 percent; however, the implementation of this NO_x control method was also assumed to increase carbon monoxide and total hydrocarbon emissions by 10 percent each.

Much of southern California is in nonattainment of NAAQS air quality standards, and regulatory bodies in that area have typically implemented stringent controls on emissions of air pollutants. It is expected that many of the controls currently required for onshore and nearshore emitters of air pollutants will soon be applied to oil and gas activities further offshore through the implementation of the air regulations for OCS activities. Therefore, controlled air emission factors are used in estimating the air emissions from activities in the California region. Uncontrolled emission factor are used in all other regions to estimate air emissions associated with onshore treatment and disposal of drilling wastes.

A number of sources were reviewed to reexamine the emission factors utilized in previous estimates, by EPA for the 1991 proposal[4] and by Walk, Haydel & Associates in 1989[2], of non-water quality environmental impacts. EPA's recent review of emissions factors included environmental impact statements developed by the Minerals Management Service (MMS) of the Department of Interior, EPA reports, contractor reports prepared for EPA and MMS, and contacts with MMS and EPA's Office of Air Quality Planning and Standards (OAQPS).[6] Table XVIII-2 presents the uncontrolled and controlled emissions factors used to develop air emissions from onshore disposal of drilling waste. (Note that the factors are not all based on the same units.)

TABLE XVIII-2

UNCONTROLLED AND CONTROLLED EMISSION FACTORS

Source	Supply BATS (lb/1000 Gallons)		Cranes (g/bhp-hr)	Trucks (g/mile)	Wheel Tractor (lb/hr)	Track-type Dozer (lg/hr)	Auxiliary Generator (g/bhp-hr)
	Idle	Transit					
Nitrogen Oxides (NO_X)							
- Uncontrolled	419.6	391.7	14.0	11.44	1.269	0.827	14.0
- Controlled	335.7	313.4	11.2	NA	NA	NA	NC
Total Hydrocarbons (THC)							
- Uncontrolled	22.6	16.8	1.12	2.53	0.188	0.098	1.12
- Controlled	24.9	18.5	1.232	NC	NA	NA	NC
Sulfur Dioxide (SO_2)							
- Uncontrolled	28.48	28.48	0.931	NA	0.090	0.076	0.931
- Controlled	7.12	7.12	0.23	NA	NA	NA	NC
Carbon Monoxide (CO)							
- Uncontrolled	59.8	78.3	3.03	8.67	3.59	0.201	3.03
- Controlled	65.8	86.1	3.33	NA	NA	NA	NC
Total Suspended Particulates (TSP)							
- Uncontrolled	33.0	33.0	1.0	NA	0.136	0.058	1.0
- Controlled	NC	NC	NC	NA	NC	NC	NC

NOTES: NC = No Controls
NA = Not Available

2.1.3 Interaction With OCS Air Regulations

The regulation of air emissions from outer continental shelf (OCS) sources prior to the passage of the Clean Air Amendments of 1990 (CAA) was the sole responsibility of the Minerals Management Service (MMS), which administered the Department of the Interior (DOI) air quality rules (30 CFR 270.45, 46). The CAA partitioned the regulation of air emissions from OCS sources between MMS, which will continue to administer the DOI regulations for the Western and Central Gulf of Mexico planning areas, and EPA, which has responsibility for the regulation of OCS sources for all other OCS planning areas. The Central and Western Gulf of Mexico planning area are located west of 87.5 degrees longitude (near the border of Florida and Alabama).

On September 4, 1992, EPA promulgated new requirements to control air pollution from OCS sources (57 *FR* 40792). The purpose of the requirements is to attain and maintain Federal and State ambient air quality standards, and to provide for equity between onshore facilities and OCS facilities located within 25 miles of state seaward boundaries (<u>outer</u> boundary of territorial seas). It should be noted that the offshore guidelines under the Clean Water Act will apply to all activities located seaward of the <u>inner</u> boundary of the territorial seas, and thus includes the territorial seas, the contiguous zone and the ocean.

The OCS rule establishes two separate regulatory regimes. For sources within 25 miles of states' seaward boundaries, the requirements are the same as those that would be applicable if the source were located in the corresponding onshore area (COA). Sources located beyond 25 miles of states' seaward boundaries are subject to federal requirements for Prevention of Significant Deterioration (PSD), New Source Performance Standards (NSPS) and, to the extent that they are rationally related to the attainment and maintenance of federal and state ambient air quality standards or to PSD, National Emission Standards for Hazardous Air Pollutants (NEHSHAPS). All OCS sources operating adjacent to any state other than Texas, Louisiana, Mississippi, or Alabama will be subject to requirements under one of the above regimes.

The National Ambient Air Quality Standard (NAAQS) attainment classification of the onshore area determines the degree of additional control and emission offset requirements for OCS sources within 25 miles of a state seaward boundary (except in the Central and Western GOM planning areas). If any part of the onshore area adjacent to an OCS planning area is designates as nonattainment for a pollutant, then the regulatory requirements applicable to the nonattainment classification for that area would apply to the entire area of the OCS planning area within 25 miles of the State seaward boundary.

Air emission offset costs consist of those costs related to the trading of emission reductions. The Emission Offset Trading Policy was initiated by EPA in December 1976. The offset policy applies to new or expanding emission sources in nonattainment areas. In these areas, a new operation producing emissions must secure offsetting emission reductions from existing sources in order to compensate for the increases in emissions from the new source. The primary vehicle for accomplishing these offsets is the Emission Reduction Credit (ERC).

In theory, and ERC can result from a process change, a retrofit of control technology, or a shutdown of an operation. The ERC, once established, represents a marketable commodity which can be transferred either among firms or internal to one firm. Emission offsets are required for new sources that wish to construct a facility in an offshore area adjacent to an onshore area that is already exceeding the NAAQS for a particular pollutant.

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

For the purpose of analysis for the offshore guidelines, the following criteria have been used to quantify any potentially needed emission offsets and the associated costs:

- The pollutants which would require offsetting because of nonattainment of ozone standards are NO_x and volatile organic compounds (VOC), which are a fraction of the total hydrocarbon emissions. For the purpose of analyses under the proposed effluent guidelines, the total hydrocarbon (THC) emissions are used to quantify and cost emissions offsets for VOC.

- All drilling activity off California, regardless of the distance from shore or whether it occurs in State or Federal waters, is considered to result in incremental increases NO_x and hydrocarbons which would require emissions offsets.

- No offsets are quantified for the Eastern Gulf of Mexico. This is based on the low level of drilling activity projected for the entire Eastern Gulf of Mexico, coupled with the fact that the actual area which could trigger the need for offsets is only a small fraction of the planning area. Any errors introduced by this exclusion would be negligible in comparison to the other compliance costs associated with the offshore guidelines, as well as in relation to the total drilling costs and total air emissions resulting from the drilling activities.

- Emissions requiring offsets are to be offset in the ratio of 1.2:1. In other words, a source would be required to obtain offsets or reduce emissions by 1.2 tons for every one ton of new emissions.

- The cost of emissions offsets used in the final rulemaking for the offshore guidelines is an annual cost of $15,000 (1992 dollars) for NO_x and $5,000 (1992 dollars) for VOC.[1]

- Only those emissions strictly due to discharge limitations of the offshore guidelines are considered to be an incremental cost attributable to the guidelines. Any emissions offsets necessary to offset the level of air emissions currently generated by drilling activities are a cost of doing business borne by the operators and are not considered incremental costs attributable to the offshore guidelines.

- Only those emissions occurring within 25 miles of the drill site area are considered to require emissions offsets.

2.2 SOLIDS WASTE GENERATION AND MANAGEMENT

The regulatory options considered for this rule will not cause generation of additional solids as a result of the treatment technology. However, spent drilling fluids and drill cuttings contain high levels of solids; and therefore, under any zero-discharge option, these drilling fluids and drill cuttings would be disposed of onshore.

EPA estimates that drilling activity in the offshore subcategory generates approximately 7.7 million barrels per year of drilling wastes (drilling fluids and drill cuttings). Of that volume, about 760,000 barrels per year of drilling waste already are disposed of onshore to comply with current BPT effluent limitations and NPDES permit requirements.

Prior to the 1990/1991 proposals, EPA surveyed State and local regulatory agencies and disposal facilities in late 1989 and early 1990 to estimate permitted disposal capacities of sites which could treat and dispose of drilling waste. The evaluation reviewed the situation in the three major areas where onshore disposal of offshore drilling waste would be necessary: Gulf of Mexico, California, and Alaska.

2.2.1 Gulf of Mexico Region

A March 1991 study, entitled "Onshore Disposal of Drilling Waste: Capacity and Cost of Onshore Disposal Facilities," investigated permitted disposal capacity.[7] EPA found that in the Gulf of Mexico, most of the existing permitted disposal sites are located relatively near the coast, because that is where the demand for such disposal sites exists. Under State law in Texas and Louisiana, onshore oil drilling facilities are allowed to use on-site drilling pits for storage of drilling fluids and drill cuttings and upon closure, drilling waste at onshore facilities can be either buried onsite, land spread, or injected into an underground formation. Because State law allows onsite disposal of drilling fluids and drill cuttings, most onshore waste is disposed of at the drilling site. Most of the waste currently being disposed of in commercial oilfield waste disposal facilities originate from coastal drilling operations and offshore operations (that do not meet the current BPT effluent limitations and NPDES permit requirements).

The 1991 study classified disposal sites in the Gulf of Mexico into three categories. First, Tier I sites included those permitted to accept nonhazardous oilfield wastes and which were accepting wastes from offshore. These sites are located in very close proximity to shore, are generally accessible by boat or barge, and charge competitive rates for disposal. Tier 2 sites included facilities that were permitted to accept nonhazardous oilfield wastes but were not doing so because of their relative distance from drill sites, their lack of marine unloading terminals or water access, and their inability to compete with the rates charged by Tier 1 facilities. Finally, Tier 3 sites were those permitted to accept hazardous waste and which could theoretically accept oilfield wastes, should there be no other alternative. The study projected the combined permitted capacity of Tier 1 and Tier 2 sites at 30.7 million barrels of drilling wastes per year, with Tier 3 sites providing an additional 10.9 million barrels per year permitted capacity.

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

Accordingly, it is appropriate to determine how much of the permitted capacity is actually available for disposal of drilling fluids and drill cuttings generated offshore. Disposal estimates for the 1990 and 1991 proposals did not take into account the increased volume of coastal-generated drilling wastes resulting from a Region VI general permit that, if promulgated as proposed, will require zero discharge of drilling fluids and drill cuttings by facilities in the coastal subcategory in Louisiana and Texas. EPA anticipates an increase of 1.1 million barrels per year of coastal drilling waste requiring onshore disposal as a result of these new permit requirements.

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

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

Because EPA wanted to make a realistic estimate of disposal capacity, EPA included in its estimates of available disposal capacity only those facilities that are currently accepting the type of drilling fluids and drill cuttings that would be generated offshore. EPA excluded one site which is permitted but not yet constructed (BFI). EPA also excluded another site (Goolong Newpark) because its permit is currently suspended. EPA also excluded a facility in northern Louisiana (Campbell Wells) because disposal at this facility would require at least a 5-hour truck ride, resulting in additional air emissions, energy use, and significantly higher disposal costs than the other sites which are located closer to shore.

Based on this analysis, total permitted capacity in the Gulf of Mexico region is estimated to be 8.5 million barrels (MM/bbls) per year. A review of the receipts from available disposal facilities indicated that approximately 3 MM/bbls of wastes were accepted for treatment and/or disposal at these facilities in 1989. Using the permitted capacity estimate of 8.5 MM/bbls per year, approximately 5.5 MM/bbls per year of onshore disposal capacity is available to accept additional drilling wastes (8.5 - 3.0 = 5.5. MM/bbls per year available capacity).[8]

EPA has determined that the volume of offshore-generated drilling wastes resulting from the regulatory option requiring zero discharge at 3 miles, regardless of whether onshore disposal is driven by this rule or State water quality standards, would occupy 33 percent of the excess available landfill disposal capacity. Even taking a facility such as Campbell Wells into account, EPA predicts that the offshore-generated drilling wastes from the 3 mile zero-discharge option would occupy 28 percent of the excess landfill disposal capacity. While this level of non-water quality environmental impact is acceptable to EPA, EPA is concerned that any greater area of zero-discharge (even if the Campbell Wells facility is included as an available site in the analysis) would occupy too great a percentage of excess landfill disposal capacity.

EPA has used a conservative estimate of excess disposal capacity for several reasons. EPA is concerned that its estimate of the amount of drilling fluids and drill cuttings requiring onshore disposal may be an underestimate because the amount of drilling fluids and drill cuttings expected to be required disposed of onshore by the Region VI coastal drilling permit ranges from 671,000 to 1,620,000 bbl/yr. If EPA used the upper bound estimate, this would change the percentage of excess available landfill disposal capacity needed to accept the increased volume of drilling wastes to a range of 35 to 42 percent (depending on whether the Campbell Wells facility was included).

In addition, EPA is well aware of many of the commenter's concerns that it is difficult to permit these facilities, and that a number of factors, such as citizen opposition and potential toxic tort liability issues, may make it difficult to keep some of these facilities in operation. Accordingly, EPA attempted to identify permitted facilities in Louisiana and Texas where EPA feels reasonably confident that these facilities will remain available over a 15-year period. At the same time, the option selected by EPA allows for sufficient additional available excess capacity should some of these facilities unexpectedly close in the future.

2.2.2 California Region

California laws and regulations provide for oil and gas wastes to be designated either hazardous or nonhazardous. Drilling wastes in California are considered nonhazardous provided the operator uses only approved additives and fluids. Although offshore drilling wastes requiring onshore disposal in California would be nonhazardous if the operator uses the approved additives and fluids in the drilling operations, disposal options appear limited. While in theory it may be possible to dispose of any oilfield waste in local Class III (nonhazardous waste that will not decompose) landfills, local regulatory agencies have indicated that they are not inclined to allow such disposal unless the waste is first stabilized for use as landfill cover. If not stabilized and disposed in a Class III landfill, the alternative disposal option for offshore drilling waste is disposal at a Class I hazardous waste site. In the 1991 study report, permitted Class III (stabilized, nonhazardous waste) disposal capacity was estimated at 3.4 million barrels per year and the Class I (hazardous waste landfill) disposal capacity at 6.5-10.5 million barrels per year.[7] It was projected that the facilities available to perform the stabilization necessary to allow disposal at Class III landfills were operating at no more than 50 percent of the permitted capacity. As part of the final rulemaking, EPA reevaluated capacity estimates and to be approximately 19.4 million barrels per year (including 15.4 MMbbl/yr for Class III landfills) in the California region.[9]

Under the option requiring zero discharge of all drilling wastes for the California region, EPA projects that 233,000 bbl/yr of offshore generated drilling fluids and drill cuttings will require onshore disposal at facilities on the California coast. Comparing that to the projected disposal capacity in the California region, EPA concluded that the wastes requiring onshore disposal under this option would use less than 2 percent of the available disposal capacity. Other distances considered for this rule require less than 1 percent of the disposal capacity.

2.2.3 Alaska Region

The 1991 report identified no commercially operating disposal sites in Alaska accepting offshore drilling wastes.[7] This lack of commercial disposal sites would require operators to transport the drilling wastes to another location such as Washington, Oregon, or California for disposal; apply to the State of Alaska for a permit to operate a commercial disposal facility for the offshore wastes; apply to the State to allow disposal of drilling wastes which have been either thermally treated or chemically stabilized (solidification) in currently existing landfills; or inject the drilling wastes into underground formations. Injection of slurried drilling fluids and drill cuttings is currently practiced on a limited trial basis on the North Slope and has been considered for onshore use in other regions such as the Gulf of Mexico. However, the technology of injecting slurried drill cuttings is not sufficiently developed to apply to offshore at this time.

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

2.2.4 Atlantic Region

Landfill capacities were not evaluated along the Atlantic coast due to the limited projected drilling activity in this region. Currently there is no drilling activity in this region and there has not been any drilling activity since the early 1980's.

2.3 CONSUMPTIVE WATER USE

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

2.4 OTHER FACTORS

2.4.1 Impact of Marine Traffic on Coastal Waterways

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

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

MMS data show that there were 25,000 service vessel trips to support oil and gas related activities in Federal waters of the Gulf of Mexico in 1988. These data do not include vessel traffic destined for coastal or offshore activities in the State territorial seas and therefore under counts actual boat traffic. In estimating the vessel traffic resulting from this rule, EPA projected that transporting drilling wastes ashore from a well subject to zero discharge would require, on average, 5 to 6 service vessel trips and result in a differential increase of approximately 740 service vessel trips per year. Ninety percent (90%), or 670, of these boat trips would take place in the Gulf of Mexico. Despite the limitations of the MMS data, it does indicate that the differential increase in boat traffic due to this rule would be less than 3 percent of all service vessel traffic.[10]

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

Since service vessels must have unimpeded access to supply bases to continue servicing offshore activities, maintenance dredging of navigation channels would be required regardless of whether this rule was promulgated. The channels used by vessel traffic in transporting drilling wastes to onshore disposal sites would also continue to be maintained since over 700,000 barrels of offshore generated drilling wastes are already being transported to shore in compliance with NPDES permit limitations. Recalling that oil and gas related traffic accounts for less than 10 percent of all commercial use of the navigation channels and that oil/gas related vessel traffic resulting from this rule will increase less than 3 percent, any increase in vessel traffic due to this rule is expected to total less than 1 percent of all commercial traffic in these channels (3% of 10%, or 0.3%). No significant increase in dredging activities is anticipated as a result of this rule.

2.4.2 Safety

In 1992, EPA evaluated data associated with personnel casualties that occurred on mobile offshore drilling units (MODUs) and offshore supply vessels (OSV) for the years 1981 through 1990. The personnel casualty data was compiled from the U.S. Coast Guard's Personnel Casualty file (PCAS). The study focused on accidents related to the handling and transportation of material, since this would be most similar to the additional activities required should a zero discharge limitation be imposed.[11]

EPA reviewed the data to determine the number of accidents related to activities similar to those that would occur during the handling of drill cuttings. The following types of accidents were selected from the database as indicators of injuries that may have resulted from the handling of drill cuttings:

- Struck by falling object
- Struck by flying object
- Struck by moving object
- Struck by vessel
- Struck by object, NOC
- Bumped fixed object
- Cargo handling-NOC
- Line handling
- Caught in Lines
- Pinched/crushed
- Unknown
- Not classified.

The PCAS file is composed of U.S. Coast Guard 2692 forms and contains the following information: case number, last name, first name, date of birth, status, nature of the accident, nature of the injury, the body part injured, result, cause, office, location of the person at the time of accident, the activity of the person at the time of the accident, the body of water, the year the vessel was built, the date of the casualty, industry time, company time, name of the vessel, operating company, vehicle identification number, flag, service, use, design, length, gross tonnage, time on duty, and case year.

Form 2692 is entitled, "Report of Marine Accident, Injury or Death." The 2692 form is included in the PCAS file based on the occurrence of the following:

- A death
- An injury to five or more persons in a single incident
- An injury causing any person to be incapacitated for more than 72 hours.

The actual injury report forms were not reviewed, therefore the specific number of casualties resulting from the handling of drilling waste is not known. The casualties evaluated in this report are the total number of casualties for general types of accidents and may include casualties resulting from other drilling activities as well as the handling of drilling waste.

In addition to the type of accident, the survey identified the cause of the accidents. The cause of accidents was further classified into "safety related" and "not safety related" categories. Safety related causes were results of accidents that could be avoided through some form of increased safety awareness. Non-safety related causes were those accidents considered unavoidable. Table XVIII-3 presents the primary causes and classification of accidents on MODUs and OSVs.

Evaluation of the database revealed that the majority of the accidents were caused by human factors related to safety practices and procedures. Accident reports from one oil and gas company "showed that more than 80 percent of all injury accidents were caused by human behavior or more specifically, by unsafe practices."[12] The casualty data from MODUs indicated that the cause of more than 75 percent of the reported casualties were due to human factors related to safety practices and procedures. For OSVs more than 60 percent of the reported casualties were related to safety practices and procedures. The evaluation the personnel casualty data concluded the following:

- Greater than 75 percent of the accidents occurring on MODUs between 1981 to 1990 were caused by human error or unsafe practices or procedures.

- Greater than 60 percent of the accidents occurring on OSVs between 1981 to 1990 were caused by human error or unsafe practices or procedures.

- Over the last three years (1988-1990) the number of casualties on MODUs has decreased while the drilling activity has remained fairly constant.

- From the data examined it is not possible to predict the effect of transportation of drilling waste to shore on the number of personnel casualties.

TABLE XVIII-3

PRIMARY CAUSES AND CLASSIFICATION OF ACCIDENTS ON MODUS AND OSVS

Primary Cause	Classification
Adverse Weather	unavoidable
Carelessness, Another or Self	avoidable
Chemical Reaction	unavoidable
Deck Cluttered or Slippery	avoidable
Equipment or Material Failure	unavoidable
Failure to use Safety Equipment	avoidable
Improper Loading/Storage	avoidable
Improper Maintenance or Supervision	avoidable
Improper Tools/Equipment	avoidable
Inadequate/Missing Guarding or Railing	avoidable
Inadequate Training	avoidable
Misuse of Tools/Equipment	avoidable
Mooring Line Surge	unavoidable
Physical Factors, Self	avoidable
Unsafe Movement, Another or Self	avoidable
Unsafe Practice, Another or Self	avoidable
Vessel Casualty	unavoidable
Unknown	unavoidable
Not Elsewhere Classified	unavoidable

- The number of casualties occurring on supply vessels does not appear to be directly related to drilling activity.

- Since the number of increased crane handling events is very small in relation to the total number of handling operations occurring at drilling and production sites, no discernable increase in casualties attributable to onshore disposal of drilling wastes is anticipated.

The technology basis for compliance with zero discharge limitations of drilling fluids and cuttings will be either to bulk load the material onto barges or to load individual containers onto offshore service vessels (OSV). Typically, OSVs are used for facilities located in the OCS while barges are used in protected, near shore drilling sites. Containers or boxes are used to hold the excess and/or used muds and cuttings and have an approximate capacity of 25 barrels. Cranes load these containers onto and off of offshore service vessels. The implementation of a zero discharge standard may ultimately increase crane-related and transport activity because of the need to deliver drilling fluids and cuttings wastes to shore for land disposal.

2.4.3 Administrative/Enforcement Considerations

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

EPA also received comments regarding the potential for confusion and the administrative burden in selecting a delineation other than the pre-existing 3-mile boundary between State territorial seas and Federal waters. In all offshore areas with the exception of Texas and the Gulf coast of Florida, States assert jurisdiction over the mineral rights off their shores up to a distance of 3 miles. There is overlapping jurisdiction under the CWA and the Submerged Lands Act (SLA) (43 U.S.C. 1301, et seq.). Under the CWA, States have jurisdiction over waters extending 3 miles from shore. Persons discharging to these waters are required to comply with any State water quality standards. Under the SLA, Texas and Florida exercise mineral rights in the Gulf of Mexico up to 3 marine leagues (approximately 10.35 statute miles). In waters beyond 3 miles, or 3 marine leagues for Texas and Florida, the MMS of the Department of the Interior leases mineral rights and manages OCS mineral operations under the authority of the Outer Continental Shelf Lands Act (OCSLA). MMS conducts periodic inspections of offshore oil and gas activities in the Federal waters under the OCSLA and, under a Memorandum of Understanding (MOU) with EPA, conducts NPDES compliance inspections on behalf of EPA in those areas. Commenters asserted that it would be more appropriate to select the State/Federal water boundary as the delineation for a zero discharge limitation, rather than the 4-mile limit so that MMS or the Region would not have to inspect for zero discharge at any facilities within the 1-mile band between 3 and 4 miles while inspecting for compliance with a different set of discharge limitations beyond 4 miles. EPA also believes that the 3-mile option, which is consistent with State waters under the CWA, will help to simplify the regulatory framework applicable to offshore waters. Another factor considered by EPA is that only about 12 wells per year (less than two percent of the total wells drilled annually) are expected to be drilled in the 1-mile band between 3 and 4 miles from shore.

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

3.0 PRODUCED WATER

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

3.1 ENERGY REQUIREMENTS AND AIR EMISSIONS

Energy requirements and resulting air emissions for the control options considered by EPA are presented in Table XVIII-4. Estimates are presented incremental to current BPT limitations and thus represent the expected increase above current emissions levels and energy consumption.

TABLE XVIII-4

NON-WATER QUALITY ENVIRONMENTAL IMPACTS PRODUCED WATER

Option	Fuel Requirements (thousand BOE/year)		Total Emissions (tons/yr)	
	BAT	NSPS	BAT	NSPS
Option 2 Flotation All	281	117	169	31
Option 3 Zero 3 Miles Gulf & Alaska	331	236	185	164
Option 4 Zero Discharge Gulf & Alaska	1,709	1,529	1,041	849

As can be seen from Table XVIII-4, the option requiring zero discharge of all produced water greatly increases air emissions and fuel requirements as compared to the flotation all option. This is due primarily to the energy required to operate the injection pumps.

3.1.1 Energy Consumption

Fuel requirements were calculated for gas turbines assuming a heating value of 1,050 Btu/scf of natural gas and an average fuel consumption of 10,000 Btu/hp-hr, or 9.5 (10,000/1,050) standard cubic feet (scf) of natural gas per horsepower-hour (hp-hr).[13] The usage rate, in hours per year (hrs/yr), for the design systems is assumed to be 365 days per year or 8,760 hours per year. For example, the fuel requirements to operate a 1,700 BPD gas flotation unit is: 12.25 hp x 8,760 hrs/yr x 9.5 scf/hp-hr = 1.02 million standard cubic feet (scf) of natural gas. This section provides a detailed discussion on the development of fuel requirements for each treatment technology.

3.1.1.1 Gas Flotation

Energy requirements for gas flotation represent the power required to operate an induced gas flotation system designed for compliance with oil and grease limitations in produced water discharged to surface waters. The following assumptions were made in calculating the energy and fuel requirements for gas flotation:

- The gas flotation equipment will be run by electricity. The electric power will be supplied by existing natural gas driven generators on the platform. Fuel requirements and air emissions for gas flotation represent only the additional electricity that must be generated on the platform for operation of gas flotation systems.

- Only those existing platforms which do not already have a gas flotation system and are assumed to add-on a gas flotation system were included in estimating fuel requirements under BAT. For those existing facilities which already have gas flotation units installed, any incremental increase in fuel usage incurred from complying with the BAT limitations for the final rule would be negligible.

- For new sources, only those new platforms without gas flotation systems included in the facility (20 percent of new structures do not include gas flotation in the design) were included in estimating fuel requirements under NSPS. For new sources expected to install gas flotation regardless of the rulemaking (80 percent of all new structures include gas flotation in the design of the facility), any incremental increase in fuel requirements from complying with the NSPS limits for the final rule would be negligible.

Energy requirements for commercially available gas flotation systems were obtained from equipment vendors for four different size systems ranging in treatment capacity from 1,700 to 77,000 barrels per day (BPD).[14] Electricity requirements in kilowatts (kW) for each unit were calculated using 0.75 kW/hp as a conversion factor. Table XVIII-5 presents unit energy and fuel requirements for the four gas flotation units evaluated.

TABLE XVIII-5

FUEL REQUIREMENTS FOR GAS FLOTATION UNITS[14]

Feed Rate (BPD)	1,700	10,000	25,000	77,000
Power Required (hp)	12.25	20.5	40.5	100.5
Electricity Required (kW)	9.2	15.4	30.4	75.4
Fuel Required (scf/yr)	1.02×10^6	1.7×10^6	3.37×10^6	8.36×10^6

3.1.1.2 Granular Filtration

Energy requirements for granular filtration represent the power required to operate the filter as an add-on to BPT. Produced water treated by granular filtration is discharged directly to surface water. The backwash stream from the granular filtration unit is concentrated and dewatered using a centrifuge. The concentrated backwash stream that is dewatered is approximately 0.5 percent of the influent produced water flow.[15] The following assumptions were made in calculating the energy and fuel requirements for granular filtration:

- The granular filtration equipment will be run by electricity. The electric power will be supplied by existing natural gas driven generator on the platform. Fuel requirements and air emissions have been calculated for this generator based on the additional electricity that must be generated for this treatment technology.
- There will only be one 26 hp centrifuge per structure with a capacity of 2000 barrels/day.
- The centrifuge will only be operated when necessary (i.e. if the flow to the centrifuge is 100 barrels per day then the centrifuge will only be operated every 20 days when sufficient flow has been accumulated).
- If the flow to the centrifuge is less than one barrel per day then a centrifuge will not be used at that structure.

Energy requirements for commercially available granular filtration systems were obtained from equipment vendors for five different size systems ranging in treatment capacity from 1,000 to 40,000 barrels per day (BPD).[16] Electricity requirements in kilowatts (kW) for each unit was calculated using 0.75 kW/hp as a conversion factor. Table XVIII-6 presents unit energy requirements for the five granular filtration units evaluated.

TABLE XVIII-6

FUEL REQUIREMENTS FOR GRANULAR FILTRATION UNITS[16]

Filter Feed Rate (BPD)	1,000	5,000	10,000	20,000	40,000
Power Required (hp)	10	20	30	40	80
Electricity Required (kW)	7.5	15	22.5	30	60
Fuel Required (scf/yr)	8.32×10^5	1.66×10^6	2.50×10^6	3.33×10^6	6.66×10^6

Energy requirements to operate the centrifuge are based a backwash flow rate of 0.5 percent of the produced water flow. Available data on the energy requirements for the centrifuge were obtained from contacts with an equipment vendor.[17] The smallest capacity centrifuge quoted was a 2000 BPD unit that required a 26 HP motor. Electricity requirements in kilowatts (kW) for each unit was calculated using 0.75 kW/hp as a conversion factor. Since the flow to the centrifuge for each design system was well below 2,000 BPD, it was assumed that the backwash tank will have a storage capacity for 2,000 barrels and the centrifuge would only be operated when 2000 barrels have accumulated in the backwash tank. The total usage in hours per year (hrs/yr) of the centrifuge was then calculated by dividing the influent backwash flow by the centrifuge design capacity and taking the product of 24 hrs/day and 365 days/yr. For example, if the filter system treats 1,000 BPD of produced water, the flow to the centrifuge is: 1,000 BPD x 0.005, or 5 BPD. Usage = (5/2,000) x 24 x 365 (hrs/yr), or 22 hrs/yr. Table XVIII-7 presents centrifuge unit energy and fuel requirements and usage for the five granular filtration units.

TABLE XVIII-7

FUEL REQUIREMENTS AND USAGE FOR CENTRIFUGE[15,17]

Filter Feed Rate (BPD)	1,000	5,000	10,000	20,000	40,000
Centrifuge Feed Rate (BPD)	5	25	50	100	200
Power Required (hp)	26	26	26	26	26
Electricity Required (kW)	19.5	19.5	19.5	19.5	19.5
Usage (hrs/yr)	22	110	219	438	876
Fuel Required (scf/yr)	$5.43x10^3$	$2.72x10^4$	$5.41x10^4$	$1.08x10^5$	$2.16x10^5$

3.1.1.3 Reinjection

Energy requirements for reinjection were estimated based on produced water being pretreated by granular filtration and then injected into a well with a capacity of 6,000 BPD at an injection pressure of 1800 psig. The following assumptions were made in calculating the energy requirements for reinjection:

- There will be one operating natural gas driven injection pump (turbine type) per structure.
- The granular filtration and centrifuge equipment will be run by electricity. The electric power will be supplied by existing natural gas driven generator on the platform. Fuel requirements and air emissions have been calculated for this generator based on the additional electricity that must be generated for this treatment technology.

Energy requirements for commercially available injection pumps were obtained from equipment vendors for three different size pumps ranging in capacity from 2,000 to 20,000 BPD.[18] Table XVIII-8 presents unit energy and fuel requirements for the three injection pumps evaluated.

TABLE XVIII-8

FUEL REQUIREMENTS FOR INJECTION PUMPS[18]

Pump Capacity (BPD)	2,000	6,000	20,000
Energy Required (hp)	75	200	742
Fuel Required (scf/yr)	$6.24x10^6$	$1.66x10^7$	$6.17x10^7$

For those model platforms with average produced water flow rates less than 2,000 BPD, an annual usage in hrs/yr was calculated as a function of the ratio of the model flow versus 2,000 BPD.

3.1.2 Air Emissions

The air emissions were calculated for each model platform by taking the product of brake specific emission factors, the usage in hours (that is, hours per year), and the horsepower requirements. Air emissions for each treatment technology were calculated on the basis of "brake specific" emission factors for natural gas-fired turbines.[6] Table XVIII-9 presents the emission factors used in calculating air emissions for all three treatment technologies.

TABLE XVIII-9

EMISSION FACTORS FOR NATURAL GAS-FIRED TURBINES[19]

Units	CO	NO_x	SO_2	HC
g/hp-hr	0.05	1.7	0.002*	0.055

*This factor depends on the sulfur content of the fuel used. For natural gas-fired turbines, AP-42 (Table 3.2-1) gives this emission factor based on assumed sulfur content of pipeline gas of 2000 g/10^6 scf.[13]

3.1.2.1 Gas Flotation

Air emissions for the four gas flotation design systems were calculated based on horsepower, usage, and emission factors. For example, CO emissions resulting from operating the 1,700 BPD system for 8,760 hrs/yr are: 12.25 hp x 8,760 hrs/yr x 0.05 g/hp-hr x 10^{-6} tons/g = 0.005 tons/yr. Table XVIII-10 presents air emissions in tons/yr for the four gas flotation units evaluated.

TABLE XVIII-10

AIR EMISSIONS FOR GAS FLOTATION UNITS

		Air Emissions (tons/yr)				
Feed Rate (BPD)	HP	CO	NO_x	SO_2	HC	Total
1,700	12.25	0.005	0.18	0.0002	0.005	0.190
10,000	20.5	0.009	0.31	0.0004	0.009	0.328
25,000	40.5	0.018	0.60	0.0007	0.018	0.637
77,000	100.5	0.044	1.50	0.0017	0.044	1.590

3.1.2.2 Granular Filtration

Air emissions for the granular filtration design systems including the centrifuge were calculated based on horsepower, usage, and emission factors. For example, CO emissions resulting from operating the 1,000 BPD filter for 8,760 hrs/yr are: 10 hp x 8,760 hrs/yr x 0.05 g/hp-hr x 10^{-6} tons/g = 0.004 tons/yr. The CO emissions resulting from operating the 26 hp centrifuge for 22 hrs/yr is: 26 hp x 22 hrs/yr x 0.05 g/hp-hr x 10^{-6} tons/g = 0.00003 tons/yr. Total CO emissions for the granular filtration system treating 1000 BPD of produced water is: 0.004 + 0.00003, or 0.004 tons/yr. Table XVIII-11 presents air emissions for the five granular filtration systems evaluated, including the centrifuge.

TABLE XVIII-11

AIR EMISSIONS FOR GRANULAR FILTRATION SYSTEMS

Total For Granular Filtration System					
	Air Emissions (tons/yr)				
Produced Water Flow (BPD)	CO	NO_x	SO_2	HC	Total
1,000	0.004	0.150	0.000	0.004	0.158
5,000	0.009	0.303	0.000	0.009	0.321
10,000	0.013	0.457	0.001	0.013	0.484
20,000	0.019	0.615	0.001	0.019	0.654
40,000	0.036	1.230	0.001	0.036	1.303

3.1.2.3 Reinjection

Air emissions for the three reinjection design pumps were calculated based on horsepower, usage, and emission factors. For example, CO emissions resulting from operating the 2,000 BPD system for

8,760 hrs/yr are: 75 hp x 8,760 hrs/yr x 0.05 g/hp-hr x 10^{-6} tons/g = 0.033 tons/yr. Table XVIII-12 presents air emissions in tons/yr for the three injection pumps units evaluated.

TABLE XVIII-12

AIR EMISSIONS FOR REINJECTION PUMPS

		Air Emissions (tons/yr)				
Feed Rate (BPD)	**hp**	**CO**	**NO_x**	**SO_2**	**HC**	**Total**
2,000	75	0.033	1.117	0.001	0.033	1.184
6,000	200	0.088	2.978	0.004	0.088	3.158
20,000	742	0.325	11.050	0.013	0.325	11.713

3.2 UNDERGROUND INJECTION OF PRODUCED WATER

In the 1987 Report to Congress (EPA/530-SW-88-003), 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 hoes 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) requires mechanical 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. The authority of the UIC program extends to all offshore injection wells located in state territorial waters, but does not apply to injection wells located in federal waters.

Many states have primacy of 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 an because current state programs vary significantly. State requirements for new injection wells prior to enactment of the UIC program have evolved over time, and construction ranges for 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.

4.0 WELL TREATMENT, WORKOVER, AND COMPLETION FLUIDS

The non-water quality environmental impacts associated with disposal of TWC fluids are the fuel requirements and air emissions from onshore injection of these fluids. Based on two trips to disposal facilities in Louisiana, EPA concluded that in general, centralized onshore injection facilities use diesel powered injection pumps.[19,20]

One facility injects 10,000 bbl/day of fluids using two 235 horsepower (hp) diesel powered positive displacement piston pumps. Average injection pressure for two wells is 1,000 psig. Total diesel usage is an average of 200 gal/day.[19] The second facility injects 8,000 bbl/day of fluids using one 165 hp diesel powered triplex pumps. Average injection pressure is 260 psig. Total diesel usage is on the average 40 gal/day.[20]

Diesel internal combustion engines cover a wide variety of industrial applications, including fork lift trucks, mobile refrigeration units, generators, pumps, and portable drilling equipment. Because the rated power of these engines covers a wide range, from 45 to 600 hp, substantial differences in both annual usage (hrs/yr) and engine duty cycles exist. Because of these variables and to calculate fuel requirements for both BAT and NSPS for onshore injection of TWC fluids, EPA concluded that an average diesel usage based on the data from the two facilities represents a reasonable assumption. Air emissions were calculated by taking the product of the specific emission factors (lb/gal) and the average diesel usage.[13] Table XVIII-13 presents the specific emission factors used in air emission calculations.

TABLE XVIII-13

EMISSION FACTORS FOR DIESEL POWERED INDUSTRIAL EQUIPMENT[13]

Pollutant	Emission Factor (lb/gal)
Carbon monoxide (CO)	0.102
Hydrocarbons (HC)	0.0375
Nitrogen oxides (NO_x)	0.469
Sulfur oxides (SO_x)	0.0312
Particulates	0.0335

4.1 BAT Fuel Requirements and Air Emissions

The average diesel fuel requirements for onshore injection of workover and treatment fluids subjected to BAT limitations were calculated based on the total volume of 140,999 bbl/yr of workover and treatment fluids requiring onshore disposal. Completion fluids are not included in the BAT estimates because completion fluids are considered wastes from new sources only. An average total diesel usage of 1,762.5 gal/yr was calculated from the two facilities data, as shown in Table XVIII-14.

TABLE XVIII-14

BAT DIESEL FUEL REQUIREMENTS

	Houma Saltwater Co.	Campbell Wells Land Treatment
Total BAT Injection Fluid Volume	140,999 bbl/yr	140,999 bbl/yr
Number of Operating Days	18 (based on 8,000 bbl/day)	14 (based on 10,000 bbl/day)
Diesel Usage per Day	40 gal	200 gal
Total Diesel Usage	705 gal/yr	2,820 gal/yr
Average Diesel Usage: (705 + 2,820)/2 = 1,762.5 gal/yr		

Incremental air emissions due to BAT limitations, were calculated by taking the product of the average diesel usage in gal/yr and the emission factors in lb/gal shown in Table XVIII-14. The values of air emission rates calculated by this method are shown in Table XVIII-15.

TABLE XVIII-15

BAT AIR EMISSION RATES FOR WORKOVER AND TREATMENT FLUIDS

Pollutant	Air Emissions (lb/yr)	Air Emissions (tons/yr)
Carbon monoxide (CO)	179.77	0.090
Hydrocarbons (HC)	66.09	0.033
Nitrogen oxides (NO_x)	826.60	0.413
Sulfur oxides (SO_x)	54.99	0.027
Particulates	59.04	0.030
Total:	1,186.49	0.59

4.2 NSPS Fuel Requirements and Air Emissions

The average diesel fuel requirements for onshore injection of TWC fluids subjected to NSPS limitations were calculated based on the total volume of 741,750 bbl over 15 years, or 49,450 bbl/yr of TWC fluids requiring onshore disposal. An average total diesel usage of 618 gal/yr was calculated from the two facilities data, as shown in Table XVIII-16.

TABLE XVIII-16

NSPS DIESEL FUEL REQUIREMENTS

	Houma Saltwater Co.	Campbell Wells Land Treatment
Total NSPS Injection Volume	49,450	49,450
Number of Operating Days	6 (based on 8,000 bbl/day)	5 (based on 10,000 bbl/day)
Diesel Usage per Day	40 gal	200
Total Diesel Usage	247 gal/yr	989 gal/yr
Average Diesel Usage: (247 + 989)/2 = 618 gal/yr		

Incremental air emissions due to NSPS limitations, were calculated by taking the product of the average diesel usage in gal/yr and the emission factors in lb/gal shown in Table XVIII-16. The values of air emission rates calculated by this method are shown in Table XVIII-17.

TABLE XVIII-17

NSPS AIR EMISSION RATES FOR TWC FLUIDS

Pollutant	Air Emissions (lb/yr)	Air Emissions (tons/yr)
Carbon monoxide (CO)	63.05	0.032
Hydrocarbons (HC)	23.18	0.012
Nitrogen oxides (NO_x)	289.90	0.145
Sulfur oxides (SO_x)	19.29	0.010
Particulates	20.71	0.010
Total:	416.13	0.21

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SECTION XIX

BEST MANAGEMENT PRACTICES

Section 304(e) of the Clean Water Act authorizes the Administrator to prescribe best management practices (BMPs) to control "plant site runoff, spillage or leaks, sludge or waste disposal, and drainage from raw material storage." Section 402(a)(1) and NPDES regulation (40 CFR 122) also provide for best management practices to control or abate the discharge of pollutants when numeric effluent limitations are infeasible. However, the Administrator may prescribe BMPs only where he finds that they are needed to prevent a "significant amount" of toxic or hazardous pollutants from entering navigable waters.

The final rule for the offshore subcategory of the oil and gas extraction point source category does not establish "best management practices" (BMP's). EPA determined that effective BMP's could more accordingly be developed by the regional offices and be established in the regional NPDES permits. Although BMP's were not developed for this rule, EPA identified several general areas where BMP's may be applicable. The following paragraphs describe the some examples of BMP's that could be established and be effective through the issuance of NPDES permits.

In the offshore oil and gas industry, there are various types of wastes that may be affected by the application of BMPs in NPDES permits. These include deck drainage and leaks and spills from various sources. The potential for contamination of deck drainage is related to the degree segregation practiced. "Clean" deck drainage should be segregated from sources of contamination. Many sources exist on an offshore platform where leaks or spills could occur. The areas should be managed so that all leaks and/or spills are contained and not discharged overboard.

Good operation and maintenance practices reduce waste flows and improve treatment efficiencies, as well as reduce the frequency and magnitude of system upsets. Some examples of good offshore operation are:

1. Separation of waste crankcase oils from deck drainage collection systems.
2. Minimization of wastewater treatment system upsets by the controlled usage of deck washdown detergents.

3. Reduction of oil spillage through the use of good prevention techniques such as drip pans and other handling and collection methods.

4. Elimination of oil drainage from pump bearings and/or seals by directing the drainage to the crude oil processing system.

5. If oil is used as a spotting fluid, careful attention to the operation of the drilling fluid system could result in the segregation from the main drilling fluid system of the spotting fluid and the drilling fluid that has been contaminated by the spotting oil. Once segregated, the contaminated drilling fluid can be disposed of in an environmentally acceptable manner.

6. Careful application of drill pipe dope to minimize contamina-tion of receiving water and drilling muds. Pipe dope can contribute high amounts of lead and probably other metals to discharged muds.

Careful planning, good engineering, and a commitment on the part of the operating, maintenance, and management personnel are needed to ensure that the full benefits of all pollution reduction facilities are realized.

SECTION XX

GLOSSARY AND ABBREVIATIONS

Act: The Clean Water Act.

Agency: U.S. Environmental Protection Agency.

Air/Gas Lift: Lifting of liquids by injection of air or gas directly into the well.

Annulus or Annular Space: The space between the drill stem and the wall of the hole or casing.

AOGA: Alaskan Oil and Gas Association.

API: American Petroleum Institute.

Barite: Barium sulfate. An additive use to weight drilling mud.

Barrel: 42 United States gallons at 60 degrees Fahrenheit.

BAT: The best available technology economically achievable, under Section 304(b)(2)(b) of the Act.

BCT: The best conventional pollutant control technology.

Bentonite: A clay additive used to increase viscosity of drilling mud.

Blowout: A wild and uncontrolled flow of subsurface formation fluids at the earth's surface.

Blowout Preventer (BOP): A device to control formation pressures in a well by closing the annulus when pipe is suspended in the well or by closing the top of the casing at other times.

BMP: Best management practices under section 304(e) of the Act.

BOD: Biochemical oxygen demand.

BPT: The best practicable control technology currently available, under section 304(b)(1) of the Act.

Bottom-Hole Pressure: Pressure at the bottom of a well.

Brackish Water: Water containing low concentrations of any soluble salts.

Brine: Water saturated with or containing a high concentration of common salt (sodium chloride); also any strong saline solution containing such other salts as calcium chloride, zinc chloride, calcium nitrate, etc.

Casing: Large steel pipe used to "seal off" or "shut out" water and prevent caving of loose gravel formations when drilling a well. When the casings are set, drilling continues through and below the casing with a smaller bit. The overall length of this casing is called the string of casing. More than one string inside the other may be used in drilling the same well.

Centrifuge: A device for the mechanical separation of solids from a liquid. Usually used on weighted muds to recover the mud and discard solids. The centrifuge uses high-speed mechanical rotation to achieve this separation as distinguished from the cyclone-type separator in which the fluid energy alone provides the separating force.

Christmas Tree: Assembly of fittings and valves at the top of the casing of an oil well that controls the flow of oil from the well.

Clean Water Act: The Federal Water Pollution Control Act Amendments of 172 (33 U.S.C. 1251 et seq.), as amended by the Clean Water Act of 1977 (Pub. L. 95-217) and the Water Quality Act of 1987 (Pub. L. 100-4).

Condensate: Hydrocarbons which are in the gaseous state under reservoir conditions but which become liquid either in passage up the hole or at the surface.

Connate Water: Water that was laid down and entrapped with sedimentary deposits as distinguished from migratory waters that have flowed into deposits after they were laid down.

Cuttings: Small pieces of formation that are the result of the chipping and/or crushing action of the bit.

Deck Drainage: Any waste resulting from deck washings, spillage, rainwater, and runoff from gutters and rains including drip pans and work areas within facilities addressed by this document.

Desilter: Equipment, normally cyclone type, for removing extremely fine drilled solids from the drilling mud stream.

Development Facility: Any fixed or mobile structure addressed by this document that is engaged in the drilling of potentially productive wells.

Diesel Oil: 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.

Differential Pressure Sticking: Sticking which occurs because part of the drill string (usually the drill collars) becomes embedded in the filter cake resulting in a non-uniform distribution of pressure around the circumference of the pipe. The conditions essential for sticking require a permeable formation and a pressure differential across a nearly impermeable filter cake and drill string.

Disposal Well: A well through which water (usually salt water) is returned to subsurface formations.

Domestic Waste: Materials discharged from sinks, showers, laundries, and galleys located within facilities addressed by this document. Included with these wastes are safety shower and eye wash stations, hand wash stations, and fish cleaning stations.

Drill Cuttings: Particles generated by drilling into subsurface geologic formations and carried to the surface with the drilling fluid.

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

Drill Pipe: Special pipe designed to withstand the torsion and tension loads encountered in drilling.

Emulsion: A substantially permanent heterogenous mixture of two or more liquids (which are not normally dissolved in each other, but which are) held in suspension or dispersion, one in the other, by mechanical agitation or, more frequently, by adding small amounts of substances known as emulsifiers. Emulsions may be oil-in-water, or water-in-oil.

EPA: United States Environmental Protection Agency.

Exploration Facility: Any fixed or mobile structure addressed by this document that is engaged in the drilling of wells to determine the nature of potential hydrocarbon reservoirs.

Field: The area around a group of producing wells.

Flocculation: The combination or aggregation of suspended solid particles in such a way that they form small clumps or tufts resembling wool.

Fluid Injection: Injection of gases or liquids into a reservoir to force oil toward and into producing wells. (see also "Water Flooding.")

Formation: Various subsurface geological strata penetrated by well bore.

Formation Damage: Damage to the productivity of a well resulting from invasion of mud particles into the formation.

Fracturing: Application of excessive hydrostatic pressure which fractures the well bore.

Freewater Knockout: An oil/water separation tank at atmospheric pressure.

Gas Lift: A means of stimulating flow by aerating a fluid column with compressed gas.

GC: Gas chromatography.

Gun Barrel: An oil-water separation vessel.

Heater-Treater: A vessel used to break oil water emulsion with heat.

Hydrostatic Head: Pressure which exists in the well bore due to the weight of the column of drilling fluid; expressed in pounds per square inch (psi).

Inhibitor: An additive which prevents or retards undesirable changes in the product. Particularly, oxidation and corrosion; and sometimes paraffin formation.

Invert Oil Emulsion Drilling Fluid: A water-in-oil emulsion where fresh or salt water is the dispersed phase and diesel, crude, or some other oil is the continuous phase. Water increases the viscosity and oil reduces the viscosity.

Killing a Well: Bringing a well under control that is blowing out. Also, the procedure of circulating water and drilling fluids into a completed well before starting well servicing operations.

96-hr LC50: The concentration of a test material that is lethal to 50% of the test organisms in a bioassay after 96 hours of constant exposure.

M10: Those offshore facilities continuously manned by ten or more persons.

M9IM: Those offshore facilities continuously manned by nine or fewer persons or only intermittently manned by any number of persons.

Mud Pit: A steel or earthen tank which is part of the surface drilling mud system.

Mud Pump: A reciprocating, high pressure pump used for circulating drilling mud.

Multiple Completion: A well completion which provides for simultaneous production from separate zones.

NPDES Permit: A 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.

OOC: Offshore Operators Committee.

PESA: Petroleum Equipment Suppliers Association.

Packer Fluid: Any fluid placed in the annulus between the tubing and casing above a packer. Along with other functions, the hydrostatic pressure of the packer fluid is utilized to reduce the pressure differentials between the formation and the inside of the casing and across the packer itself.

Pressure Maintenance: The amount of water or gas injected vs. the oil and gas production so that the reservoir pressure is maintained at a desired level.

Priority Pollutants : The toxic pollutants listed in 40 CFR Part 423, Appendix A.

Production Facility: Any fixed or mobile facility that is used for active recovery of hydrocarbons from producing formations. The production facility begins operations with the completion phase.

Produced Water: The water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas, and can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process.

Produced Sand: Slurried particles used in hydraulic fracturing and the accumulated formation sands and scale particles generated during production. This includes desander discharge from the produced water waste stream and blowdown of the water phase from the produced water treating system.

RCRA: Resource Conservation and Recovery Act (Pub. L. 94-580) of 1976. Amendments to Solid Waste Disposal Act.

Reservoir: Each separate, unconnected body of producing formation.

Rotary Drilling: The method of drilling wells that depends on the rotation of a column of drill pipe with a bit at the bottom. A fluid is circulated to remove the cuttings.

Sanitary Waste: Human body waste discharged from toilets and urinals located with facilities addressed by this document.

Separator: A vessel used to separate oil and gas by gravity.

Sequestering Agents: A substance that maintains status quo bonding. In the case of treatment fluids, they prevent precipitation of iron compounds. Organic acids are most commonly used.

Shaleshaker: Mechanical vibrating screen to separate drilled formation cuttings carried to surface with drilling mud.

Shut In: To close valves on a well so that it stops producing; said of a well on which the valves are closed.

Skim Pile:

Spot: The introduction of oil to a drilling fluid system for the purpose of freeing a stuck drill bit or string.

Stripper Well (Marginal Well): A well which produces such small volume of oil that the gross income therefrom provides only a small margin of profit or, in many cases, does not even cover actual cost of production.

Surfactant: A substance that affects the properties of the surface of a liquid or solid by concentrating on the surface layer.

Territorial Seas: The belt of the seas measured from 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, and extending seaward a distance of 3 miles.

TSS: Total Suspended Solids.

USCG: United States Coast Guard.

USGS -United States Geological Survey.

Water Flooding: Water is injected under pressure into the formation via injection wells and the oil is displaced toward the producing wells.

Well Completion: In a potentially productive formation, the completion of a well in a manner to permit production of oil, the walls of the hole above the producing layer (and within it if necessary) must be supported against collapse and the entry into the well of fluids from formations other than the producing layer must be prevented. A string of casing is always run and cemented, at least to the top of the producing layer, for this purpose. Some geological formations require the use of additional techniques to "complete" a well such as casing the producing formation and using a "gun perforator" to make entry holes, the use of slotted pipes, consolidating sand layers with chemical treatment, and the use of surface-actuated underwater robots for offshore wells.

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 production.

Well Head: Equipment used at the top of a well, including casing head, tubing head, hangers, and Christmas Trees.

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.

Workover: To clean out or otherwise work on a well in order to increase or restore production.

Workover Fluid: Salt solutions, weighted brines, polymers, or other specialty additives used in a producing well to allow safe repair and maintenance or abandonment procedures.

APPENDIX 1

BAT AND NSPS PROFILES OF MODEL PRODUCTION PLATFORMS

TABLE A1-1

BAT "MODEL" PROFILE OF EXISTING PRODUCTION PLATFORMS
3-MILE DELINEATION

Structure Type		Total Number Of Structures This Type	Total Number Of Structures This Size Now Injecting	Total Number Producing Wells/Struct.	Avg. Flow Prod. Water BWPD/ Structure	Max. Flow Prod. Water BWPD/ Structure
Within 3 Miles						
Oil Facilities						
Gulf of Mexico:	Gulf 1a	76		1	247	421
	Gulf 1b	10		1	293	461
	Gulf 4	3		4	1,214	1,871
	Gulf 6	1		6	1,822	2,807
	Gulf 12	0		10	2,723	4,500
	Gulf 24	0		18	5,312	8,382
	Gulf 40	0		32	9,603	15,162
	Gulf 58	0		50	15,030	23,969
Pacific Coast:	Pacific 16	0		14	6,460	11,506
	Pacific 40	0		33	14,282	27,272
	Pacific 70	0		60	25,545	50,718
Sub-Totals:		90	0	-	-	-
Oil and Gas Facilities						
Gulf of Mexico:	Gulf 1a	0		1	260	434
	Gulf 1b	3		1	304	468
	Gulf 4	6		4	1,249	1,894
	Gulf 6	0	2	6	1,877	2,841
	Gulf 12	1		10	2,833	4,582
	Gulf 24	0		18	5,479	8,489
	Gulf 40	0		32	9,874	15,312
	Gulf 58	0		50	15,427	24,161
Pacific Coast:	Pacific 16	5		14	6,460	11,506
	Pacific 40	0		32	14,282	27,272
	Pacific 70	5		60	25,545	50,718
Sub-Totals:		20	2	-	-	-
Gas Facilities						
Gulf of Mexico:	Gulf 1a	89		1	16	68
	Gulf 1b	6		1	14	68
	Gulf 4	4		4	55	272
	Gulf 6	2		6	77	408
	Gulf 12	0		10	148	680
	Gulf 24	0		18	244	1,224
Pacific Coast:	Pacific 16	0		14	307	1,190
Sub-Totals:		101	0	-	-	-
Totals For Within 3 Miles Facilities:		211	2	-		

TABLE A1-1 (Continued)

BAT "MODEL" PROFILE OF EXISTING PRODUCTION PLATFORMS 3-MILE DELINEATION

Structure Type		Total Number Of Structures This Type	Total Number Of Structures This Size Now Injecting	Total Number Producing Wells/Struct.	Avg. Flow Prod. Water BWPD/ Structure	Max. Flow Prod. Water BWPD/ Structure
Beyond 3 Miles						
Oil Facilities						
Gulf of Mexico:	Gulf 1a	69		1	247	421
	Gulf 1b	11	1	1	293	461
	Gulf 4	41		4	1,214	1,871
	Gulf 6	18	1	6	1,822	2,807
	Gulf 12	22	1	10	2,723	4,500
	Gulf 24	5		18	5,312	8,382
	Gulf 40	1		32	9,603	15,162
	Gulf 58	0		50	15,030	23,969
Pacific Coast:	Pacific 16	0		14	6,460	11,506
	Pacific 40	0		33	14,282	27,272
	Pacific 70	0		60	25,545	50,718
Sub-Totals:		167	3	-	-	-
Oil and Gas Facilities						
Gulf of Mexico:	Gulf 1a	222	1	1	260	434
	Gulf 1b	95		1	304	468
	Gulf 4	114		4	1,249	1,894
	Gulf 6	127	5	6	1,877	2,841
	Gulf 12	218	8	10	2,833	4,582
	Gulf 24	196	2	18	5,479	8,489
	Gulf 40	2		32	9,874	15,312
	Gulf 58	0		50	15,427	24,161
Pacific Coast:	Pacific 16	0		14	6,460	11,506
	Pacific 40	5		32	14,282	27,272
	Pacific 70	13		60	25,545	50,718
Sub-Totals:		995	16	-	-	-
Gas Facilities						
Gulf of Mexico:	Gulf 1a	438		1	16	68
	Gulf 1b	264	1	1	14	68
	Gulf 4	172		4	55	272
	Gulf 6	158	1	6	77	408
	Gulf 12	104		10	148	680
	Gulf 24	39		18	244	1,224
Pacific Coast:	Pacific 16	1		14	307	1,190
Sub-Totals:		1,176	2	-	-	-
Totals For Beyond 3 Miles Facilities:		2,338	21	-	-	-
Totals for All Facilities:		2,549	23	-	-	-

TABLE A1-2

BAT "MODEL" PROFILE OF EXISTING PRODUCTION PLATFORMS 4-MILE DELINEATION

Structure Type		Total Number Of Structures This Type	Total Number Of Structures This Size Now Injecting	Total Number Producing Wells/Struct.	Avg. Flow Prod. Water BWPD/ Structure	Max. Flow Prod. Water BWPD/ Structure
Within 4 Miles						
Oil Facilities						
Gulf of Mexico:	Gulf 1a	102		1	247	421
	Gulf 1b	11		1	293	461
	Gulf 4	26		4	1,214	1,871
	Gulf 6	1		6	1,822	2,807
	Gulf 12	0		10	2,723	4,500
	Gulf 24	0		18	5,312	8,382
	Gulf 40	0		32	9,603	15,162
	Gulf 58	0		50	15,030	23,969
Pacific Coast:	Pacific 16	0		14	6,460	11,506
	Pacific 40	0		33	14,282	27,272
	Pacific 70	0		60	25,545	50,718
Sub-Totals:		140	0	-	-	-
Oil and Gas Facilities						
Gulf of Mexico:	Gulf 1a	27		1	260	434
	Gulf 1b	16		1	304	468
	Gulf 4	16		4	1,249	1,894
	Gulf 6	2	2	6	1,877	2,841
	Gulf 12	4		10	2,833	4,582
	Gulf 24	8		18	5,479	8,489
	Gulf 40	0		32	9,874	15,312
	Gulf 58	0		50	15,427	24,161
Pacific Coast:	Pacific 16	7		14	6,460	11,506
	Pacific 40	0		32	14,282	27,272
	Pacific 70	7		60	25,545	50,718
Sub-Totals:		87	2	-	-	-
Gas Facilities						
Gulf of Mexico:	Gulf 1a	151		1	16	68
	Gulf 1b	30		1	14	68
	Gulf 4	13		4	55	272
	Gulf 6	3		6	77	408
	Gulf 12	0		10	148	680
	Gulf 24	0		18	244	1,224
Pacific Coast:	Pacific 16	0		14	307	1,190
Sub-Totals:		197	0	-	-	-
Totals For Within 4 Miles Facilities:		424	2	-		

TABLE A1-2 (Continued)

BAT "MODEL" PROFILE OF EXISTING PRODUCTION PLATFORMS 4-MILE DELINEATION

Structure Type		Total Number Of Structures This Type	Total Number Of Structures This Size Now Injecting	Total Number Producing Wells/Struct.	Avg. Flow Prod. Water BWPD/ Structure	Max. Flow Prod. Water BWPD/ Structure
Beyond 4 Miles						
Oil Facilities						
Gulf of Mexico:	Gulf 1a	43		1	247	421
	Gulf 1b	10	1	1	293	461
	Gulf 4	18		4	1,214	1,871
	Gulf 6	18	1	6	1,822	2,807
	Gulf 12	22	1	10	2,723	4,500
	Gulf 24	5		18	5,312	8,382
	Gulf 40	1		32	9,603	15,162
	Gulf 58	0		50	15,030	23,969
Pacific Coast:	Pacific 16	0		14	6,460	11,506
	Pacific 40	0		33	14,282	27,272
	Pacific 70	0		60	25,545	50,718
Sub-Totals:		117	3	-	-	-
Oil and Gas Facilities						
Gulf of Mexico:	Gulf 1a	195	1	1	260	434
	Gulf 1b	82		1	304	468
	Gulf 4	104		4	1,249	1,894
	Gulf 6	125	5	6	1,877	2,841
	Gulf 12	215	8	10	2,833	4,582
	Gulf 24	188	2	18	5,479	8,489
	Gulf 40	2		32	9,874	15,312
	Gulf 58	0		50	15,427	24,161
Pacific Coast:	Pacific 16	1		14	6,460	11,506
	Pacific 40	5		32	14,282	27,272
	Pacific 70	11		60	25,545	50,718
Sub-Totals:		928	16	-	-	-
Gas Facilities						
Gulf of Mexico:	Gulf 1a	376		1	16	68
	Gulf 1b	240	1	1	14	68
	Gulf 4	163		4	55	272
	Gulf 6	157	1	6	77	408
	Gulf 12	104		10	148	680
	Gulf 24	39		18	244	1,224
Pacific Coast:	Pacific 16	.1		14	307	1,190
Sub-Totals:		1,080	2	-	-	-
Totals For Beyond 4 Miles Facilities:		2,125	21	-	-	-
Totals All Facilities:		2,549	23	-	-	-

TABLE A1-3

"MODEL" PROFILE OF NEW PRODUCTION PLATFORMS
3-MILE DELINEATION

Structure Type		Total Structures for the 15 Year Period	Total Number Producing Wells/Struc.	Total Producing Wells	Avg. Flow Prod. Water BWPD/ Structure	Max. Flow Prod. Water BWPD/ Structure
Within 3 Miles						
Oil Facilities						
Gulf of Mexico:	Gulf 1b	0	1	0	312	473
	Gulf 4	0	4	0	1,285	1,913
	Gulf 6	0	6	0	1,926	2,869
	Gulf 12	0	10	0	2,934	4,653
	Gulf 24	0	18	0	5,633	8,579
	Gulf 40	0	32	0	10,126	15,439
	Gulf 58	0	50	0	15,800	24,325
Pacific Coast:	Pacific 16	0	14	0	7,066	11,909
	Pacific 40	0	33	0	15,671	28,171
	Pacific 70	0	60	0	27,748	51,979
Alaska:						
Beaufort Sea	Gravel Island 48	2	40	80	48,674	74,503
Sub-Totals:		2	-	80	-	-
Oil and Gas Facilities						
Gulf of Mexico:	Gulf 1b	0	1	0	321	478
	Gulf 4	15	4	108	1,315	1,929
	Gulf 6	15	6	90	1,973	2,893
	Gulf 12	14	10	140	3,027	4,712
	Gulf 24	0	18	0	5,778	8,655
	Gulf 40	0	32	0	10,362	15,547
	Gulf 58	0	50	0	16,145	24,463
Pacific Coast:	Pacific 16	0	14	0	7,066	11,909
	Pacific 40	0	32	0	15,671	28,171
	Pacific 70	0	60	0	27,748	51,979
Sub-Totals:		44	-	338	-	-
Gas Facilities						
Gulf of Mexico:	Gulf 1b	11	1	23	14	68
	Gulf 4	19	4	132	49	272
	Gulf 6	28	6	168	74	408
	Gulf 12	0	10	0	134	680
	Gulf 24	0	18	0	222	1,224
Pacific Coast:	Pacific 16	0	14	0	268	1,190
Sub-Totals:		58	-	323	-	-
Totals For Within 3 Miles Facilities:		104	-	741		

TABLE A1-3 (Continued)

"MODEL" PROFILE OF NEW PRODUCTION PLATFORMS 3-MILE DELINEATION

Structure Type		Total Number Of Structures This Type	Total Number Of Producing Wells per Structure	Total Producing Wells	Avg. Flow Prod. Water BWPD/ Structure	Max. Flow Prod. Water BWPD/ Structure
Beyond 3 Miles						
Oil Facilities						
Gulf of Mexico:	Gulf 1b	0	1	0	312	473
	Gulf 4	0	4	0	1,285	1,913
	Gulf 6	0	6	0	1,926	2,869
	Gulf 12	0	10	0	2,934	4,653
	Gulf 24	0	18	0	5,633	8,579
	Gulf 40	0	32	0	10,126	15,439
	Gulf 58	0	50	0	15,800	24,325
Pacific Coast:	Pacific 16	0	14	0	7,066	11,909
	Pacific 40	0	33	0	15,671	28,171
	Pacific 70	0	60	0	27,748	51,979
Sub-Totals:		0	-	0	-	-
Oil and Gas Facilities						
Gulf of Mexico:	Gulf 1b	12	1	12	321	478
	Gulf 4	74	4	248	1,315	1,929
	Gulf 6	19	6	114	1,973	2,893
	Gulf 12	70	10	700	3,027	4,712
	Gulf 24	62	18	1,116	5,778	8,655
	Gulf 40	27	32	864	10,362	15,547
	Gulf 58	0	50	0	16,145	24,463
Pacific Coast:	Pacific 16	0	14	0	7,066	11,909
	Pacific 40	0	32	96	15,671	28,171
	Pacific 70	0	60	24	27,748	51,979
Sub-Totals:		264	-	3,390	-	-
Gas Facilities						
Gulf of Mexico:	Gulf 1b	53	1	41	14	68
	Gulf 4	127	4	452	49	272
	Gulf 6	61	6	366	74	408
	Gulf 12	96	10	960	134	680
	Gulf 24	52	18	936	222	1,224
Pacific Coast:	Pacific 16	0	14	0	268	1,190
Sub-Totals:		389	-	2,755	-	-
Totals for Beyond 3 Miles Facilities:		653	-	6,145	-	-
Totals All Facilities:		757	-	6,886	-	-

TABLE A1-4

"MODEL" PROFILE OF NEW PRODUCTION PLATFORMS 4-MILE DELINEATION

Structure Type		Total Structures for the 15 Year Period	Total Number Producing Wells/Struc.	Total Producing Wells	Avg. Flow Prod. Water BWPD/ Structure	Max. Flow Prod. Water BWPD/ Structure
Within 4 Miles						
Oil Facilities						
Gulf of Mexico:	Gulf 1b	0	1	0	312	473
	Gulf 4	0	4	0	1,285	1,913
	Gulf 6	0	6	0	1,926	2,869
	Gulf 12	0	10	0	2,934	4,653
	Gulf 24	0	18	0	5,633	8,579
	Gulf 40	0	32	0	10,126	15,439
	Gulf 58	0	50	0	15,800	24,325
Pacific Coast:	Pacific 16	0	14	0	7,066	11,909
	Pacific 40	0	33	0	15,671	28,171
	Pacific 70	0	60	0	27,748	51,979
Alaska:						
Beaufort Sea	Gravel Island 48	2	40	80	48,674	74,503
Sub-Totals:		2	-	80	-	-
Oil and Gas Facilities						
Gulf of Mexico:	Gulf 1b	0	1	0	321	478
	Gulf 4	27	4	108	1,315	1,929
	Gulf 6	15	6	90	1,973	2,893
	Gulf 12	14	10	140	3,027	4,712
	Gulf 24	0	18	0	5,778	8,655
	Gulf 40	0	32	0	10,362	15,547
	Gulf 58	0	50	0	16,145	24,463
Pacific Coast:	Pacific 16	0	14	0	7,066	11,909
	Pacific 40	0	32	0	15,671	28,171
	Pacific 70	0	60	0	27,748	51,979
Sub-Totals:		56	-	338	-	-
Gas Facilities						
Gulf of Mexico:	Gulf 1b	23	1	23	14	68
	Gulf 4	33	4	132	49	272
	Gulf 6	28	6	168	74	408
	Gulf 12	0	10	0	134	680
	Gulf 24	0	18	0	222	1,224
Pacific Coast:	Pacific 16	0	14	0	268	1,190
Sub-Totals:		84	-	323	-	-
Totals For Within 4 Miles Facilities:		142	-	741		

TABLE A1-4 (Continued)

"MODEL" PROFILE OF NEW PRODUCTION PLATFORMS 4-MILE DELINEATION

Structure Type		Total Number Of Structures This Type	Total Number Of Producing Wells per Structure	Total Producing Wells	Avg. Flow Prod. Water BWPD/ Structure	Max. Flow Prod. Water BWPD/ Structure
Beyond 4 Miles						
Oil Facilities						
Gulf of Mexico:	Gulf 1b	0	1	0	312	473
	Gulf 4	0	4	0	1,285	1,913
	Gulf 6	0	6	0	1,926	2,869
	Gulf 12	0	10	0	2,934	4,653
	Gulf 24	0	18	0	5,633	8,579
	Gulf 40	0	32	0	10,126	15,439
	Gulf 58	0	50	0	15,800	24,325
Pacific Coast:	Pacific 16	0	14	0	7,066	11,909
	Pacific 40	0	33	0	15,671	28,171
	Pacific 70	0	60	0	27,748	51,979
Sub-Totals:		0	-	0	-	-
Oil and Gas Facilities						
Gulf of Mexico:	Gulf 1b	12	1	12	321	478
	Gulf 4	62	4	248	1,315	1,929
	Gulf 6	19	6	114	1,973	2,893
	Gulf 12	70	10	700	3,027	4,712
	Gulf 24	62	18	1,116	5,778	8,655
	Gulf 40	27	32	864	10,362	15,547
	Gulf 58	0	50	0	16,145	24,463
Pacific Coast:	Pacific 16	0	14	0	7,066	11,909
	Pacific 40	0	32	96	15,671	28,171
	Pacific 70	0	60	24	27,748	51,979
Sub-Totals:		252	-	3,990	-	-
Gas Facilities						
Gulf of Mexico:	Gulf 1b	41	1	41	14	68
	Gulf 4	113	4	452	49	272
	Gulf 6	61	6	366	74	408
	Gulf 12	96	10	960	134	680
	Gulf 24	52	18	936	222	1,224
Pacific Coast:	Pacific 16	0	14	0	268	1,190
Sub-Totals:		363	-	2,755	-	-
Totals For Beyond 4 Miles Facilities:		615	-	6,145	-	-
Totals All Facilities:		757	-	6,896	-	-

APPENDIX 2

RAW DATA FOR ESTIMATING POLLUTANT LOADINGS FOR PRODUCED WATER

TABLE A2-1 THIRTY PLATFORM STUDY

Pollutant (µg/l)	Location									
	1 EC 33A	2 EC 14CF	3 V 119D	4 V 255A	5 SMI 23B	6 V 39D	7 SMI 6A EI	8 57A-E SMI	9 115A EI	10 120CF
2-Butanone										
2-4-Dimethylphenol	2294.00	379.00	250.00	250.00	256.00	431.67	250.00	710.00	250.00	250.00
Anthracene										
Benzene	8852.00	1650.00	737.00	2206.00	683.00	11033.17	340.00	12040.00	2037.67	3590.00
Benzo(a)pyrene	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Chlorobenzene	22.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Di-N-butylphthlate	10.00	10.00	10.00	10.00	10.00	10.00	10.00	21.00	10.00	10.00
Ethylbenzene	1753.67	80.00	34.00	249.00	187.00	2064.00	21.00	270.00	59.00	6010.00
N-Alkanes										
Napthalene	1179.33	216.00	104.00	72.00	239.00	181.83	50.00	610.00	33.50	107.00
P-chloro-M-cresol	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	43.00
Phenol	4124.67	7067.00	585.00	1028.00	10462.00	2206.50	1930.00	20812.00	65.00	930.00
Steranes										
Toluene	5575.67	1010.00	368.00	2953.00	3451.00	12541.00	163.00	5670.00	1540.00	1550.00
Triterpanes										
Total Xylenes										
Aluminum										
Arsenic										
Barium										
Boron										
Cadmium	25.00	25.00	29.00	26.00	27.00	24.50	28.00	28.00	33.00	29.00
Copper	75.00	83.00	80.00	85.00	83.00	83.00	92.00	100.00	95.00	88.00
Iron										
Lead	182.00	189.00	208.00	189.00	190.00	183.00	196.00	210.00	213.00	223.00
Manganese										
Nickel	132.00	145.00	153.00	146.00	151.00	134.50	150.00	137.00	177.00	152.00
Titanium										
Zinc	37.00	28.00	27.00	52.00	213.00	53.00	65.00	155.00	435.00	2300.00

Source: White, C.E., "Long-Term Averages for Analyte Concentrations in the Proposed Offshore Oil and Gas Regulations," September 20, 1989.

TABLE A2-2 THIRTY PLATFORM STUDY

Pollutant (µg/l)	Location									
	11 SMI 130B	12 EI 208B	13 EI 18CF	14 EI 238A	15 EI 296B	16 SS107(S9	17 SS 107(S9	18 SS 219A	19 ST 177	20 BM 2C
2-Butanone										
2-4-Dimethylphenol	250.00	250.00	250.00	250.00	250.00	250.00	250.00	250.00	250.00	250.00
Anthracene										
Benzene	2250.00	1160.00	3365.00	4100.00	2120.00	297.33	540.00	2430.00	315.00	1112.36
Benzo(a)pyrene	10.00	10.00	10.00	10.00	10.00	10.50	10.00	10.00	10.00	10.00
Chlorobenzene	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Di-N-butylphthlate	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Ethylbenzene	201.50	44.00	125.00	187.00	124.00	94.33	87.00	260.00	22.00	96.92
N-Alkanes										
Napthalene	65.50	120.00	204.00	139.00	73.00	171.00	36.00	34.00	218.00	124.67
P-chloro-M-cresol	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Phenol	208.00	240.00	762.50	950.00	560.00	1395.75	1439.00	332.00	705.00	1573.42
Steranes										
Toluene	1565.00	620.00	3842.50	2490.00	1710.00	936.67	570.00	2200.00	230.00	1113.89
Triterpanes										
Total Xylenes										
Aluminum										
Arsenic										
Barium										
Boron										
Cadmium	26.50	25.00	29.50	26.00	27.00	27.50	24.00	33.00	98.00	27.00
Copper	93.50	88.00	91.50	100.00	91.00	92.00	82.00	97.00	97.00	87.50
Iron										
Lead	200.50	188.00	189.00	213.00	176.00	197.50	205.00	206.00	2867.00	193.08
Manganese										
Nickel	147.50	144.00	139.50	130.00	139.00	136.00	138.00	158.00	177.00	131.33
Titanium										
Zinc	18.50	372.00	88.00	854.00	18.00	94.00	63.00	1070.00	28900.00	27.33

Source: White, C.E., "Long-Term Averages for Analyte Concentrations in the Proposed Offshore Oil and Gas Regulations," September 20, 1989.

TABLE A2-3 THIRTY PLATFORM STUDY

Pollutant (µg/l)	Location									
	21 BDC CF5	22 ST 135	23 WD 90A	24 WD 45E	25 WD 70I	26 GIB DB600	27 WD 105C	28 SP 62A	29 SP 24/27	30 SP 65B
2-Butanone										
2-4-Dimethylphenol	250.00	250.00	250.00	250.00	250.00	250.00	250.00	250.00	250.00	250.00
Anthracene										
Benzene	961.00	1214.17	1370.00	141.42	1777.50	400.00	450.00	2853.75	1200.00	400.00
Benzo(a)pyrene	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	15.00
Chlorobenzene	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Di-N-butylphthlate	10.00	10.00	51.00	11.50	10.00	10.00	10.00	10.00	10.00	157.00
Ethylbenzene	74.17	38.33	99.00	19.17	356.00	110.00	44.50	111.75	86.00	95.00
N-Alkanes										
Napthalene	192.92	44.00	137.00	26.42	164.50	140.00	119.50	51.75	127.00	327.50
P-chloro-M-cresol	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Phenol	2253.00	839.50	1138.00	588.50	1106.50	108.00	638.00	204.00	270.00	355.00
Steranes										
Toluene	714.58	1022.50	990.00	104.08	2305.00	590.00	342.50	1440.00	920.00	495.00
Triterpanes										
Total Xylenes										
Aluminum										
Arsenic										
Barium										
Boron										
Cadmium	25.67	29.00	25.00	27.50	27.50	23.00	33.00	27.50	25.00	24.50
Copper	83.25	88.00	1455.00	84.42	75.50		90.00	248.00		169.50
Iron										
Lead	185.67	203.00	167.00	181.83	179.50		184.00	208.00		199.00
Manganese										
Nickel	132.58	210.00	132.00	131.42	126.00	96.00	147.50	216.00		
Titanium										
Zinc	2189.67	211.50	202.00	41.58	16.00		48.50	342.00	163.00	68.50

Source: White, C.E., "Long-Term Averages for Analyte Concentrations in the Proposed Offshore Oil and Gas Regulations," September 20, 1989.

TABLE A2-4 MISCELLANEOUS STUDIES

Pollutant (µg/l)	Location												
	Three Facility Study			Middletech	Sauer Neff 87	Neff 88		Cook Inlet Study					
	Shell	Thums	Conoco	BUC 296-B	Armstrong	Lake Pelto	EI 105A	Baker	Bruce	Plat A	Granite	Tradbay	Foreland
2-Butanone	1254.80	275.00	275.00			1210.00	2130.00						
2-4-Dimethlyphenol	136.29	10.00	146.70					480.40	394.00	3.20	228.80	529.70	118.20
Anthracene	10.00	10.00	10.00					19.20	29.20	21.70	16.70	25.00	33.30
Benzene	991.58	52.48	9008.41	5325.00	3300.00	1519.00	6374.50	10570.00	20417.00	54.00	5427.00	3308.00	4968.00
Benzo(a)pyrene	10.00	10.00	10.00	1.20				18.80	21.70	19.20	17.50	17.50	25.80
Chlorobenzene	47.50	47.50	47.50			10.00	10.00	12.90	171.00	0.50	26.30	4.40	108.50
Di-n-butylpthalate	10.00	10.00	10.00										
Ethylbenzene	267.88	23.80	1009.27	850.00		50.00	35.50	416.00	787.00	3.00	299.00	155.00	208.00
N-alkanes						606.00	2677.00						
Napthalene	71.70	18.60	42.32	170.00	300.00	13.90	9.64	433.70	1754.20	13.80	1103.00	873.00	2721.30
P-chloro-m-cresol	125.70	10.00	364.17										
Phenol	158.29	10.00	379.83			291.00	1430.00	1244.70	2358.30	2.80	474.20	429.00	438.60
Steranes						92.00	63.00						
Toluene	1294.64	80.83	5305.44	6030.00	3500.00	675.00	2148.00	4986.00	9355.00	13.00	2022.00	1477.00	2100.00
Triterpanes						80.00	76.00						
Total xylenes	155.58	12.51	439.37	2780.00	2400.00	203.50	481.00	2059.00	3697.00	19.00	1573.00	522.00	960.00
Aluminum	76.06	122.98	35.00										
Arsenic	17.00	17.00	308.56										
Barium	65853.79	42695.01	49.67	3500.00		11500.00	37400.00						
Boron	32139.65	38230.13	6850.96										
Cadmium	4.00	4.00	4.00	4.00		0.12	0.32						
Copper	6.00	90.46	135.50	6.00		0.40	6.36						
Iron	730.42	8260.75	672.29	10000.00									
Lead	50.00	50.00	50.00	500.00		1.50	17.90						
Manganese	139.90	230.90	90.68	2.00									
Nickel	30.00	30.00	30.00	500.00		1.27	0.40						
Titanium	3.66	5.27	12.06										
Zinc	46.14	72.32	23.23	2.00		125.00	1220.00						

Source:
Three Facility Study: SAIC, "Produced Water Pollutant Variability Factors and Filtration Efficacy Assessments From the Three Facility Oil and Gas Study," March 1991.
Neff 87: Neff, Rabalais, and Boesch. 1987. "Offshore Oil and Gas Development Activities Potentially Causing Long-Term Environmental Effects.
Neff 88: Neff, Sauer and Maciolek. "Fate and Effects of Produced Water Discharges in Nearshore Marine Waters," August 22, 1988.
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TABLE A2-5 RABALAIS STUDY

Pollutant (μg/l)	Location											
	EI	PF-1	PF-2 OCS	PF-2 STAT	Exxon	Conoco	EP	T-1	T-2	RP-1	RP-2	EW
2-Butanone												
2-4-Dimethlyphenol												
Anthracene	10.00											
Benzene	4500.00	3225.00	119.00	462.50	2000.00	3000.00	730.00	3600.00	1000.00	580.00	760.00	910.00
Benzo(a)pyrene	10.00											
Chlorobenzene												
Di-n-butylpthalate												
Ethylbenzene	27.50	37.75	4.60	31.40	104.00	57.50	21.50	22.00	7.40	13.00	21.00	20.00
N-alkanes												
Napthalene	82.00	83.00	8.40	26.25	45.50	69.50	50.50	79.00	47.00	23.00	29.00	20.00
P-chloro-m-cresol												
Phenol	605.00	1765.00	720.00	455.00	511.00	1470.00	120.00	1900.00	640.00	490.00	570.00	190.00
Steranes												
Toluene	1050.00	957.50	56.50	159.50	642.50	1250.00	225.00	810.00	210.00	230.00	400.00	340.00
Triterpanes												
Total xylenes	210.00	332.50	24.70	57.00	167.50	400.00	111.00	180.00	51.00	100.00	300.00	140.00
Aluminum												
Arsenic												
Barium	190000.00	6200.00	15675.00	34625.00	18500.00	54250.00	24500.00	280000.00	180000.00	23000.00	5400.00	7000.00
Boron												
Cadmium	39.00	16.75	5.00	8.75	10.00	7.50	5.50	9.00	33.00	5.00	4.00	40.00
Copper	1500.00	1325.00	1200.00	1750.00	1122.50	1105.00	830.00	1500.00	1800.00	1100.00	1200.00	1700.00
Iron												
Lead	6.50	6.75	42.00	12.75	2.25	42.00	1.50	5.00	4.00	1.00	42.00	13.00
Manganese												
Nickel	7150.00	6475.00	4625.00	7625.00	4925.00	4400.00	4450.00	7400.00	7700.00	5100.00	5100.00	8800.00
Titanium												
Zinc	3150.00	1762.50	375.00	1087.00	430.00	690.00	480.00	4700.00	2500.00	420.00	260.00	440.00

Source: Rabalais, McKee and Reed: "Fate and Effects of Nearshore Discharges of OCS Produced Waters," June 1991.