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DEVELOPMENT DOCUMENT

for

PROPOSED EFFLUENT LIMITATIONS GUIDELINES & STANDARDS

for the

COASTAL SUBCATEGORY

of the

OIL AND GAS EXTRACTION POINT SOURCE CATEGORY

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SECTION I

INTRODUCTION

1.0 LEGAL AUTHORITY

The Environmental Protection Agency (EPA) is establishing these proposed Effluent Limitations Guidelines, New Source Performance and Pretreatment Standards for the Coastal 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). The proposed regulation and supporting technical information is presented in the proceeding sections of this document. This section describes EPA's legal authority for issuing them, as well as background information on prior regulations and litigations leading up to this proposal.

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 and indirect dischargers are summarized briefly below.

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)*

BAT effluent limitations guidelines, in general, 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 toxic 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) and (7) other factors as the EPA Administrator deems appropriate (Section 304(b)(2)(B) of the CWA). 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), total suspended solids (TSS), fecal coliform, pH, and any additional pollutants defined by the Administrator as conventional. The Administrator designated oil and grease as an additional conventional pollutant on July 30, 1979 (44 FR 44501).

BCT is not an additional limitation, but replaces BAT for the control of conventional pollutants. In addition to other factors specified in section 304(b)(4)(B), the 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 9, 1986).

4. *New Source Performance Standards (NSPS)*

NSPS are based on the performance of the best available demonstrated control technology (BADCT). Since new plants have the opportunity to install the best and most efficient production processes and wastewater treatment technologies, 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 generally 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.

5. *Pretreatment Standards for Existing Sources (PSES)*

Under Section 307(b) of the CWA, pretreatment standards for existing sources (PSES) are developed to prevent the discharge of pollutants that may interfere with or pass through to publicly-owned treatment works (POTWs). These types of discharges are known as indirect discharges. Pretreatment standards are technology-based and analogous to BAT effluent limitations guidelines.

6. *Pretreatment Standards for New Sources (PSNS)*

Section 307(c) of the CWA authorizes EPA to promulgate pretreatment standards for new sources (PSNS) at the same time it promulgates (NSPS). PSNS are analogous to PSES in that PSNS limitations are developed to prevent discharges of pollutants to pass through or interfere with POTWs. New indirect dischargers have the opportunity to install the best available demonstrated technologies into their new plants similar to that of NSPS since the same factors are considered when promulgating both PSNS and NSPS limitations; and therefore EPA sets PSNS after considering the same criteria considered for NSPS.

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 January 2, 1990, EPA published an Effluent Guidelines Plan (55 FR 80), in which schedules were established for

developing new and revised effluent guidelines for several industrial categories. One of the industries for which the Agency established a schedule was the Coastal Oil & Gas Extraction subcategory. Natural Resources Defense Council, Inc. (NRDC) and Public Citizen, Inc., challenged the Effluent Guidelines Plan in a suit filed in U.S. District Court for the District of Columbia (NRDC et al v. Reilly, Civ. No. 89-2980). The plaintiffs charged that EPA's plan did not meet the requirements of section 304(m). A Consent Decree in this litigation was entered by the Court on January 31, 1992. The terms of the Consent Decree are reflected in the Effluent Guidelines Plan published on September 8, 1992 (57 FR 41000). This plan requires, among other things, that EPA propose effluent guidelines for the Coastal Oil and Gas Extraction Point Source Subcategory by January 1995 and take final action on these effluent guidelines by July 1996. EPA's latest Effluent Guidelines Plan was published in 1994 (59 FR 44234, August 26, 1994).

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. The PPA 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 Coastal Subcategory

Coastal subcategory effluent limitations were proposed on October 13, 1976 (41 FR 44943). On April 13, 1979 (44 FR 22069) BPT effluent limitations guidelines were promulgated for all subcategories under the oil and gas category, but action on the BAT and NSPS regulations was deferred. Table I-1 presents the 1979 BPT limitations.

On November 8, 1989, a notice of information and request for comments on the Coastal Oil and Gas subcategory effluent limitations guidelines development was published (54 FR 46919). The notice presented the Agency's approach to effluent limitations guidelines development for BAT, BCT, and NSPS. It also requested data available to develop such limitations.

TABLE I-1

COASTAL 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
Drill Cuttings	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
Domestic Wastes	Floating Solids	No Discharge

*The free oil "no discharge" limitation is implemented by requiring no oil sheen to be present upon discharge.
Source: 40 CFR Part 435, Subpart D

In addition to the 1989 Notice of Information, regulatory and litigation activity since 1979 has occurred with respect to the definition of the coastal oil and gas industrial subcategory. The 1976 regulations had previously defined "coastal" on a geographic basis which specified boundaries in terms of longitude and latitude. Since then several changes were made or suggested regarding the definition of the coastal subcategory. These actions are summarized below:

COASTAL DEFINITIONS

1976: Land and water areas landward of the inner boundary of the territorial seas and bounded inland by a series of longitude and latitude points in Louisiana and Texas (the Chapman line).

1979: The final rule defined coastal at 40 CFR, 435 as: (1) Any body of water landward of the inner boundary of the territorial (current) seas as defined in 40 CRF 125.1 (gg) or (2) any wetlands adjacent to such waters.

Wetlands are defined as surface areas which are saturated by surface or ground water at a frequency and duration sufficient to support a prevalence of vegetation typically adapted for life in saturated soil conditions. Wetlands generally include swamps, marshes, bogs, and similar areas. (40 CFR Part 435.41 (f))

In addition, EPA attempted to reclassify approximately 1200 wells from the coastal subcategory to the onshore subcategory because these wells were located onshore but discharged to coastal waters. The American Petroleum Institute challenged this reclassification.

1981: American Petroleum Institute v. EPA, 661 F.2d 340, 354-57 (5th Cir. 1981), the Court held that EPA had failed to consider adequately the cost to the reclassified facilities of the 1979 regulatory change. As a result of the Court's decision, EPA suspended the applicability of the onshore subcategory guidelines to the reclassified wells and to any wells that came into existence in the affected area after the issuance of the 1979 redefinition. See 47 FR 31554 (July 21, 1982).

1989: EPA proposed to modify the 1979 definition to include only those facilities in saline water (greater than 0.5 parts per thousand) landward of the inner boundary of the territorial seas. (This would reclassify facilities located inland over saline and fresh water areas to the onshore or another subcategory).

As described in Section III of this document, EPA is proposing a modification to the current (1979) coastal definition for this rulemaking.

Additional related rulemakings included a series of general NPDES permits issued by EPA that set BPT, BCT and BAT limitations applicable to sources in the coastal subcategory on a Best Professional Judgment (BPJ) basis under Section 402(a)(1) of the CWA. These permits are described in Section III of this development document.

SECTION II

SUMMARY OF THE PROPOSED REGULATIONS

1.0 INTRODUCTION

The processes and operations which comprise the coastal oil and gas extraction subcategory (Standard Industrial Classification (SIC) Major Group 13) are currently regulated under 40 CFR 435, Subpart D. The existing effluent limitations guidelines, which were issued on April 13, 1979 (44 FR 22069), are based on the achievement of BPT. This section summarizes the proposed effluent limitations guidelines and NSPS for this subcategory based on BPT, BCT, BAT, BADCT. Pretreatment standards are also being proposed and are described in this section.

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 coastal 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 Chapter I Section 1.1.4.

Produced sand is the only wastestream considered in today's proposal for which BPT limits are being proposed, as it is the only wastestream considered by this proposal for which BPT limits have not been previously promulgated.

EPA believes while it could revise BPT for all of the wastestreams, administrative burden of establishing such limitations which would then require revision in NPDES permits is not warranted.

1.2 SUMMARY OF THE PROPOSED RULE

EPA proposes to establish regulations based on "best practicable control technology currently available" (BPT) for one specific wastestream for which BPT does not currently apply, and "best conventional pollutant control technology" (BCT), "pretreatment standards for existing sources" (PSES), "best available technology economically achievable" (BAT), best available demonstrated control technology (BADCT) for new sources, and "pretreatment standards for new sources" (PSNS) for all the waste streams.

Under this rule, EPA is co-proposing three options for the control of drilling fluids and cuttings (including any effluent from dewatering pit closures activities) for BAT effluent limitations guidelines, and NSPS. The three options considered contain zero discharge for all areas, except two of the options contain allowable discharges for Cook Inlet. One of these options, which would allow discharges meeting a more stringent toxicity limitation if selected for the final rule, would require an additional notice for public comment since the specific toxicity limitation has not been determined at this time. The three options are: Option 1 - zero discharge of all areas except Cook Inlet where discharge limitations require toxicity of no less than 30,000 pm (SPP), no discharge of free oil and diesel oil and no more than 1 mg/l mercury and 3 mg/l cadmium in the stock barite, Option 2 - zero discharge for all areas except for Cook Inlet where discharge limitations would be the same as Option 1, except toxicity would be set to meet a limitation between 100,000 ppm (SPP) and 1 million pm (SPP), and Option 3 - zero discharge for all areas. EPA is proposing PSES and PSNS prohibiting all discharges of drilling fluids and drill cuttings. BCT for drilling fluids and cuttings is being proposed as zero discharge for the entire subcategory except for Cook Inlet, Alaska. BCT limitations for drilling fluids and cuttings for Cook Inlet would require no discharge of free oil (as determined by the static sheen test).

EPA is proposing to prohibit discharges of produced water from all coastal subcategory operations except those located in Cook Inlet, Alaska, under BAT. Proposed BAT for coastal facilities in Cook Inlet would limit the discharge of oil and grease in produced water to a daily maximum of 42 mg/l and a thirty day average of 29 mg/l. EPA is proposing to prohibit discharges of produced water from all coastal subcategory operations under NSPS, PSNS, and PSES. BCT limits for produced waters in all coastal regions (including Cook Inlet) would be set equal to the current BPT limitations, which limit the discharge of oil and grease to a daily maximum of 72 mg/l and a thirty day average of 48 mg/l.

BCT for treatment, workover and completion fluids is proposed to be set equal to current BPT limits prohibiting discharges of free oil, with compliance to be determined by use of the static sheen test. EPA is co-proposing two options for BAT and NSPS limitations for treatment, workover and completion finds. Option 1 would require no discharge of free oil and prohibit discharges to freshwaters of Texas and Louisiana. This option reflects current practice. Option 2 would require the same limitations as the preferred option for produced water. This option would require for BAT that discharges of treatment, workover and completion fluids would be prohibited in all coastal areas except Cook Inlet. In Cook Inlet, these discharges would be required to meet a daily maximum oil and grease limitation of 42 mg/l and a 30 day average of 29 mg/l. Option 2 would require zero discharge of these fluids everywhere for NSPS. EPA proposes zero discharge as PSES, and PSNS for treatment, workover and completion fluids.

BPT, BCT, BAT, NSPS, PSES and PSNS are being proposed for produced sand and would prohibit all discharges of this wastestream. The only BPT effluent limitations guidelines being proposed today are for produced sand which is the only wastestream for which BPT limits have not been previously promulgated.

BCT, BAT, and NSPS limits being proposed for deck drainage would be set equal to current BPT limits prohibiting discharges of free oil, with compliance to be determined by use of the visual sheen test. EPA is proposing zero discharge for PSES and PSNS for deck drainage because collection and capture of this wastestream is technically impractical in many situations (as discussed later in Section VI.D.) such that its direction to POTW's would rarely if ever occur. EPA also believes that combining this wastestream with municipal treatment facilities that may already be at full capacity should not be encouraged.

BCT is being proposed for domestic wastes as equal to BPT (which is no discharge of floating solids) with an additional requirement prohibiting the discharge of garbage. BAT is being proposed for domestic wastes to prohibit discharge of foam. NSPS is being proposed for domestic wastes as equal to BCT and no discharge of foam and no discharge of garbage. No pretreatment standards are being established for domestic wastes.

BCT and NSPS limitations for sanitary wastes are being proposed as equal to the current BPT effluent limitations guidelines. Sanitary waste effluents from facilities continuously manned by ten (10) or more persons would contain a minimum residual chlorine content of 1 mg/l, with the chlorine level maintained as close to this concentration as possible. Coastal 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. BAT is not being developed for sanitary wastes because no toxic or nonconventional pollutants of concern have been identified in this waste stream. No pretreatment standards are being established for sanitary wastes.

Compliance with these proposed limitations would result in a yearly decrease of 4.3 billion pounds of toxic, nonconventional and conventional pollutants in produced water, from zero to 23 million pounds of toxic nonconventional and conventional pollutants in drilling fluids and drill cuttings (depending on the option considered), and zero to 3.9 million pounds of toxic, nonconventional, and conventional pollutants in treatment, workover, and completion fluids (depending on the option considered). The tables summarizing the requirements of this proposal are presented in Section XIV of this document, "Options Selection: Rationale and Total Costs," Tables XIV-2 through XIV-7.

As discussed in more detail in 1.4 of this section, this proposal does not take into account the regulatory effects of the recently published final EPA Region VI NPDES General Permits for production facilities (January 9, 1995). With these permits in effect, the costs of this proposal will be reduced and the actual reduction of pollutant loadings to coastal waters would be approximately 71 percent less, or 1.25 billion pounds per year, due to today's proposal. EPA will more fully incorporate the regulatory effects of the Region VI General Permits upon promulgation of the final rule.

1.3 Preventing the Circumvention of Effluent Limitations Guidelines and New Source Performance Standards

This rule also proposes a provision intended to prevent oil and gas facilities subject to Part 435 of this Title from circumventing the effluent limitations guidelines, new source performance standards and pretreatment standards applicable to those facilities by moving effluent from one subcategory to another subcategory. When EPA establishes its effluent limitations guidelines and standards, it does so based on a determination, supported by analyses contained in the rulemaking record, that facilities in that subcategory, among other factors also considered under the CWA, can technologically and economically achieve the requirements of the rule. The purpose of the rule is not accomplished if facilities move effluent from a subcategory with more stringent requirements to a subcategory with less stringent requirements or if facilities move effluent from a subcategory with less stringent requirements to a subcategory with more stringent requirements and discharge effluent at the less stringent limitations. Until now, EPA has attempted to prevent this circumvention in the National Pollution Discharge Elimination System (NPDES) permits issued for this industry. EPA believes, however, that it would

enhance the enforcement of these provisions to include them as part of the effluent limitations guidelines, new source performance standards and pretreatment standards.

Therefore, this rule proposes to prohibit oil and gas facilities from moving effluent from a subcategory with more stringent requirements to a subcategory with less stringent requirements, unless that effluent is discharged in compliance with the limitations imposed by the more stringent subcategory. For example, facilities could not move produced water generated from the onshore subcategory of the oil and gas industry (which is subject to zero discharge requirements) to the offshore subcategory of the oil and gas industry and dispose of the effluent at the offshore limitations and standards. Similarly, this rule proposes to prohibit facilities from moving produced water generated from the offshore subcategory to the coastal or onshore subcategory and discharging the produced water at the offshore limitations. (An offshore oil and gas facility could, however, pipe produced water to shore for treatment and return it to offshore waters for disposal at the offshore limits. Disposal of such produced water onshore however, would be subject to zero discharge.) EPA intends that these provisions would be applied prospectively in future NPDES permits.

1.4 THE EPA REGION VI COASTAL OIL AND GAS PRODUCTION NPDES GENERAL PERMITS

EPA's Region VI has recently published final NPDES General permits regulating produced water and produced sand discharges to coastal waters in Louisiana and Texas (60 FR 2387, January 9, 1995). The permits prohibit the discharge of produced water and produced sand derived from the coastal subcategory to any water subject to EPA jurisdiction under the Clean Water Act.

Much of the industry covered by this proposed rulemaking is also covered by these General permits. However, a significant difference between the permits and this proposal it that the permits do not cover produced water discharges derived from the Offshore subcategory wells into the main deltaic passes of the Mississippi River, or to the Atchafalaya River below Morgan City including Wax Lake Outlet. The rulemaking being proposed would cover these discharges (see the discussion in 1.3 above entitled "Preventing the Circumvention of Effluent Limitations Guidelines and New Source Performance Standards").

Due to the close proximity of the timing of the publication of the Region 6 permits and this proposal, this document presents the costs and impacts of the proposed rulemaking as if the Region VI General permits were not final. As presented in later sections of this document, this proposal (including

the facilities covered by the Region VI permit) would remove 4.3 billion pounds of pollutants in produced water from being discharged per year. The Region VI permit covers approximately 71 percent of the produced water volume being discharged in the coastal subcategory. The remaining 29 percent is derived from coastal facilities treating offshore produced waters and currently discharging them into main deltaic river passes in Louisiana, as well as from other coastal operations in the U.S. Thus, with the Region VI General permits final, this rule would actually result in the removal of 1.25 billion pounds (29 percent of 4.3 billion pounds) of pollutants per year from being discharged into coastal waters.

As also presented in later sections of this document, compliance costs of this proposed rulemaking (including the facilities covered by the Region VI permit) total approximately $40.4 million annually. With the Region VI General permits final, the costs of this rule would be reduced to approximately $19.9 million annually.

EPA will more fully incorporate regulatory effects of the Region VI General permits upon promulgation of the final rule.

SECTION III

INDUSTRY DEFINITION AND WASTESTREAMS

1.0 INTRODUCTION

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

2.0 REGULATORY DEFINITION

The coastal subcategory of the oil and gas extraction point source category, as defined in 40 CFR 435.40, is comprised of those facilities involved in exploration, development, and production operations in water bodies landward of the inner boundary of the territorial seas (shoreline). The inner boundary of the territorial seas is defined in Section 502(8) of the CWA as "the line of ordinary low water along that portion of the coast which is in direct contact with the open sea and the line marking the seaward limit of inland waters". This includes inland bays and wetlands. The inner boundary of the territorial seas has been identified by EPA for areas where coastal oil and gas activity exists.[1]

This rulemaking applies to coastal facilities included in the following SIC's: 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.

The regulations currently define the coastal subcategory as follows:

"(1) any body of water landward of the territorial seas as defined in 40 CFR 125.1(gg) or (2) any wetlands adjacent to such waters." 40 CFR Section 435.41(e). Part 125 was revised at 44 FR 32948, June 7, 1979.

EPA proposes to clarify the coastal definition in this rule. First, EPA intends to revise the regulation to state that the coastal subcategory would consist of "any oil and gas facility located in or on a water of the United States landward of the territorial seas." As suggested by the preamble to the 1979 guidelines stating that the coastal definition was intended to encompass "all facilities located over waters landward of the territorial seas, including wetlands adjacent to such waters," 44 FR 22017 April 13,

1979, EPA intended the subcategory to cover all facilities located over waters under CWA jurisdiction, including adjacent wetlands. Since 1979, courts have made it clear that isolated wetlands with an interstate commerce connection are waters of the United State subject to CWA jurisdiction. See, e.g., Hoffman Homes, Inc. v. Administrator 999 F.2d 256 (7th Cir. 1993). The revised definition would make it clear that facilities located in or on isolated wetlands would be considered to be coastal. This application of the coastal definition is consistent with Region 6 final general permit for coastal drilling operations (58 FR 49126, 49127 - September 21, 1993). Also, the revised definition would no longer refer to 40 CFR 125.1(gg) which no longer exists in the CFR. That provision, however, merely cited section 502(8) of the CWA which defines territorial seas as "the belt of 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 three miles." 40 CFR 125.1(gg) (July 1, 1978). That statutory definition is still in effect.

In addition, EPA would explicitly include in the definition of coastal certain wells located in the area between the Chapmann line and the inner boundary of the territorial seas that were determined to be coastal as a result of decision of the U.S. Court of Appeals for the Fifth Circuit. American Petroleum Institute v. EPA, 661 F.2d 340 (5th Cir. 1981). To Reflect this fact, the definition of coastal in 40 CFR 453.41(e) would be revised to include these wells.

2.1 New Source Definition

EPA proposes to apply the definition of new source promulgated in the Offshore Guidelines to the Coastal Guidelines. As discussed in the Offshore Guidelines the definition of "new source" was discussed at length in EPA's 1985 proposal for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category, (50 FR 34617-34619, August 26, 1985). As discussed in that 1985 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)). EPA is proposing 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, September 26, 1984).

The Coastal Guidelines would 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 proposes 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, August 26, 1985).

EPA intends to use the same definition of "new source" in the Coastal Guidelines as was used in the Offshore Guidelines.

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 Coastal 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 rule would temporarily exclude from the definition of "new source" those facilities that as of the effective date of the Coastal Guidelines would be 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. Once NSPS are promulgated, EPA would 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 Coastal Subcategory. EPA intends to issue as final, after opportunity for notice and comment, new source NPDES permits as soon as possible.

In summary, a drilling operation would be a new source if the drilling rig is drilling a development well (not an exploratory well) in a new water area. Exploratory drilling or drilling from an existing platform or rig that has not moved since it drilled a previously existing well would not be a new source. For production, a new source would be a facility discharging from a new site.

2.2 GEOGRAPHICAL LOCATIONS OF THE COASTAL INDUSTRY

As previously stated, coastal oil and gas activities are located on water bodies inland of the inner boundary of the territorial seas. These water bodies include inland lakes, bays and sounds, as well as saline, brackish, and freshwater wetlands. Although the definition includes inland waterbodies in all U.S. states, EPA knows of no existing coastal operations other than those in certain states bordering the coast. Thus, although the rule would apply to all areas defined as coastal, at this time the coastal industry is located only in coastal states.

Current coastal oil and gas activity exists along the Gulf Coast states of Texas, Louisiana, Alabama and Florida. The great majority of Gulf Coast activity resides in Texas and Louisiana. There, coastal oil and gas operations exist in a number of topographical situations including bays, sounds, lakes, or wetlands. Coastal oil and gas activity in Alabama is located in Mobile Bay. A small number of wells are also located on wetlands along the West Coast of Florida.

Coastal oil and gas activity in California exists in Long Beach Harbor. There, four man-made islands have been constructed solely for the purpose of oil and gas extraction.

Roughly half of the coastal oil and gas activity exists in Alaska. Deep water platforms exist in the northern part of Cook Inlet. In addition, operations resembling onshore activities (as opposed to deep water platforms) are located on the tundra wetlands of Alaska's North Slope.

See Section IV for more details regarding the number of production wells, drilling activity, and production volumes located in these areas.

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.

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, to counter balance formation pressure, and to transport drill cuttings to the surface. 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. Deck drainage can occur during production as well as drilling.

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, coastal 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 proposed 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 NPDES PERMIT STATUS

3.1 NPDES PERMITS

EPA has regulated discharges from coastal oil and gas operations in the Gulf of Mexico, California, and Alaska by general and individual National Pollutant Discharge Elimination System (NPDES) permits, issued under Section 402 of the CWA, based on BPT, State Water Quality Standards, and on Best Professional Judgment (BPJ) of BCT and BAT levels of control.

EPA's Region VI has developed general NPDES permits for each phase of oil and gas operations (drilling and production). The drilling permit was proposed in 1990 and promulgated on September 21, 1993 (58 FR 49126). The production permit was proposed on December 22, 1992 (57 FR 60926), and promulgated on January 9, 1995 (60 FR 2387).

EPA's Region X issued a BPT and BPJ general NPDES permit for oil and gas operations in the Upper Cook Inlet. However, although expired, conditions of this general permit are still fully effective and enforceable until the permit is reissued. Region X is currently in the process of reissuing the BPT and BPJ/BAT general permit for this area with proposal expected in early 1995. In addition to the general permit, the Region issued an individual permit regulating discharges from exploratory drilling

operations in Upper Cook Inlet in May 1993. The individual permit was also based on BPT and BPJ/BAT.

The State of Alabama which has been authorized to administer the NPDES program, has also issued a final NPDES general permit covering facilities in State waters, including offshore and coastal facilities (including Mobil Bay) (Permit #ALG280000, May 25, 1994). This permit specifically prohibits the discharge of drilling fluids and cuttings, and produced water. The permit also does not allow the discharge of produced sands or treatment, workover and completion fluids.

In addition to technology pollutant removal performance, regional permit requirements are based on other factors, including water quality criteria. Table III-1 presents a summary of the requirements in these permits.

3.2 STATE REQUIREMENTS

Regulations affecting the discharges from coastal oil and gas facilities in California include the California State Water Resources Control Board's 1990 "Water Quality Control Plan for Ocean Waters of California." This "Plan" requires effluent limitations be met for oil and grease of 25 mg/l (30-day average), 75 mg/l (maximum at any time), settleable solids of 1 mg/l (30-day average), 3 mg/l (Maximum at any time), turbidity 75 NTU (30-day average), and pH of 6-9, for all discharges from POTW's and industrial point sources.[3] Total suspended solids are regulated by requiring that discharges shall, as a 30 day average, remove 75% of suspended solids from the wastestreams before discharging. In addition, discharge effluent limitations are specified for acute toxicity, metals, phenolic compounds and radioactivity.

Florida's coastal oil and gas discharges are primarily regulated by Florida's Department of Environmental Protection (DEP). Regulations recently issued by the DEP prohibit the discharge of oil and gas wastestreams.[2]

TABLE III-1

NPDES PERMIT REQUIREMENTS*

REGIONAL PERMIT REQUIREMENTS					
Wastestream	**Region X (Cl 1986 BPT permit)**	**Region X Exploration Permit (1993)**	**Region VI Drilling Permit (1993)**	**Region VI Production Permit (1995)**	**Region IV Permit (1994)**
Produced Water	Monitor daily flow rate Oil & Grease: Phillips A Platform 20 mg/l daily max 15 mg/l mo. ave. Other facilities: 48/72 mg/l pH=6-9	Not applicable	Covered in Production Permit	No Discharge	No Discharge
Produced Sand	No free oil (Static Sheen)	Not applicable	Not applicable	No Discharge	No Discharge
Drilling Fluids and Cuttings	1) Toxicity: Discharge only approved generic muds 2) No free oil - static sheen 3) No discharge oil-based muds 4) 10 percent oil content for cuttings 5) No diesel oil 6) 1/3 mg/kg Hg/Cd in dry barite 7) Flow rate >40 m = 1000 bbl/hr >20-40m = 750 bbl/hr > 5-20m = 500 bbl/hr < 5m = No discharge	1) Flowrate = 750 bbl/hr 2) Use authorized muds only 3) Toxicity: 30,000 ppm in SPP 4) No free oil 5) No discharge of oil-based fluids 6) 5 percent (wt) oil content in cuttings 7) No discharge of diesel oil 8) 1 mg/kg Hg and 3 mg/kg Cd in stock barite	No Discharge	Not applicable	No Discharge
"Dewatering Effluent"	Not separately regulated	Not separately regulated	No free oil 50 mg/l TSS 125 mg/l COD pH=6-9 500 mg/l chlorides 0.5 mg/l total Cr 5.0 mg/l Zn Monitor Volume	Not Applicable	Not separately regulated
Treatment, Completion, Workover Fluids	No free oil (Static Sheen) No oil-based fluids Ph = 6-9 Oil and grease limits apply to combined discharge of any TWC Commingled with produced water	No discharge of free oil or oil-based fluids Monitor frequency of discharge and volume pH = 6.5-8.5 Oil & grease = 72 daily max. & 48 mo. avg.	Freshwater: No discharge ——— Saline Water: No toxics, No free oil (visual sheen), pH = 6-9	Not Applicable	No Discharge
Domestic Wastes	No free oil (no visible sheen) No Floating solids Monitor flow rate	Monitor flow rate No free oil (No visible sheen) No floating solids No visible foam	No discharge of solids ("garbage")	Not Applicable	See note below**

REGIONAL PERMIT REQUIREMENTS					
Wastestream	**Region X (Cl 1986 BPT permit)**	**Region X Exploration Permit (1993)**	**Region VI Drilling Permit (1993)**	**Region VI Production Permit (1995)**	**Region IV Permit (1994)**
Deck Drainage	No Fee oil (Visual Sheen) Monitor flow rate (mo. ave.)	Monitor flow rate (mo. avg.) No free oil (visual sheen)	No free oil (visual sheen) Monitor volume	Not Applicable	Monitor daily flow No free oil (visual sheen)
Sanitary Wastes	No floating solids As close as possible to, but no less than 1.0 mg/l BOD & SS*** 24 hr = 60 mg/l 7 day = 45 mg/l 30 day = 30 mg/l	No free oil (No visible sheen) No floating solids No visible foam As close as possible but no less than 1 mg/l BOD: 30 day=30 mg/l 24 hr =60 mg/l TSS: 30 day=TSS intake + 30 mg/l 24 hr = TSS intake + 60 mg/l	No floating solids BOD = 45 mg/l TSS = 45 mg/l fecal coliforms = 200/100 mls Monitor flow	Not Applicable	See note below**

* For a Compete presentation of the effluent limitations and their bases in the permits see the following: Region X Proposed General Permit for Cook Inlet (50 FR 28974, 7/17/85); Region X Final Permit for Cook Inlet (51 FR 35460, 10/3/86); Region VI Final General Permit for Drilling Operations (58 FR 49126, 9/21/93); Region VI Proposed General Permit for Production Operations (57 FR 60926, 12/22/92). The Region X Exploration Permit and the Region IV Permit are in the records for this rulemaking.

**NOTE: The Region IV permit includes limitations for sanitary and domestic wastes as presented below:

1) Treated sanitary, galley and domestic wastewater (< 10,000 gpd) from continuously manned facilities

Flow	10,000 gpd (daily maximum)	
BOD5	45 mg/l (daily max)	30 mg/l (mo ave)
TSS	45 mg/l (daily max)	30 mg/l (mo ave)
Total residual chlorine	1.0 mg/l (daily min.) maintained as close to this value as possible	
Fecal Coliform	100/100 mls (daily max. and mo ave)	
Solids	No floating solids	

2) Treated domestic wastewater (< 10,000 gpd) not commingled and cotreated with sanitary and/or galley wastewater

Flow	10,000 gpd (daily max)	monitor (mo. ave)
BOD5	45 mg/l (daily max)	30 mg/l(mo ave)
TSS	45 mg/l (daily max)	30 mg/l (mo ave)
Solids	No floating solids	

3) Treated sanitary and domestic wastewater (< 10,000 gpd) from intermittently manned facility

Flow	10,000 gpd	monitor (mo ave)
Solids	No floating solids	

4) Sanitary, galley, and domestic wastewater (< 10,000 gpd) from floating construction and/or maintenance facilities

Flow	10,000 gpd (daily max)	monitor (mo ave)
Solids	No floating solids	

*** Limits apply only to discharges to state waters and separately for BOD and SS.

4.0 REFERENCES

1. Avanti Corp, "Delineation of the Seaward Boundary of the Coastal Subcategory of the Oil & Gas Extraction Industry," May 3, 1993.

2. Rules of the State of Florida Department of Environmental Protection, Florida Geological Survey, Oil and Gas Section, Conservation of Oil and Gas Chapters 16C-25 through 16C-30. Florida Administrative Code, Chapter 16C-28, Section 28.003.

3. Wiedman, A., Memorandum to file regarding "Coastal Oil and Gas Activity in CA, AL, MS, and FL," September 6, 1994.

SECTION IV

INDUSTRY DESCRIPTION

1.0 INTRODUCTION

This section describes the major processes associated with the oil and gas extraction and production industry located in the coastal regions of the United States, and presents the current and future production and drilling activities for this industry.

2.0 DRILLING ACTIVITIES

There are two types of operations associated with drilling for oil and gas: exploratory and development. Exploratory drilling includes those operations that involve the drilling of wells to determine potential hydrocarbon reserves. Development drilling includes those operations that involve the drilling of production wells, once a hydrocarbon reserve has been discovered and delineated. Although the rigs used in exploratory and development drilling sometimes differ, the drilling process is generally the same for both types of drilling operations. Drilling in coastal areas occurs on land (or wetland areas that are dry during certain parts of the year) as well as over water or wetlands. As described later in this section, the drill site location (over water or land) as well as water depth are influential when determining the type of drilling rig used.

2.1 EXPLORATORY DRILLING

Exploration for hydrocarbon-bearing strata consists of several indirect and direct methods. Indirect methods, such as geological and geophysical surveys, identify the physical and chemical properties of formations through surface instrumentation. Geological surveys determine subsurface stratigraphy to identify rock formations that are typically associated with hydrocarbon bearing formations. Geophysical surveys establish 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 conducted from the surface with equipment specially designed for this purpose. Direct exploratory drilling, however, is the only method to confirm the presence of hydrocarbons and to determine the quantity of hydrocarbons after the indirect methods have indicated hydrocarbon potential. Exploratory wells are also referred to as "wildcats."

Shallow exploratory wells are usually drilled in the initial phases of exploration to discover the presence of oil and gas reservoirs. Deep exploratory wells are usually drilled to establish the extent of the oil or gas reservoirs, once they have been discovered. These types of exploration activities are usually of short duration, involve a small number of wells, and are conducted from mobile drilling rigs.

2.1.1 Drilling Rigs

Mobile drilling rigs are used to drill exploratory wells because they can be easily moved from one drilling location to another. These units are self contained and include all equipment necessary to conduct the drilling operation plus living quarters for the crew. The two basic types of mobile drilling units for drilling in water 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.[1]

Bottom-supported drilling units are typically used in the Gulf of Mexico region 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. In shallow and inland waters, these units may be surrounded by barges to store and to transport materials and wastes to and from the site.

Jackups are barge-mounted drilling rigs designed with extendable legs. During transport, the extendable legs are retracted. At the drill site, the legs are extended to the bottom. 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 design for jackup rigs: columnar leg and open-truss leg. Jackup rigs are used in the Cook Inlet of Alaska for exploratory drilling.

Land-based drilling rigs are also used in the coastal region of the Gulf of Mexico and on the North Slope. Land-based drilling rigs are different from water-based drilling rigs in that they are disassembled and transported from location to location by trucks. Land-based drilling rigs also take up more surface area than water-based drilling rigs. Land-based drilling rigs are usually surrounded by an earthen levee with a ditch to capture any runoff from the site. Materials and wastes are transported to and from the drill site by truck. Onsite living quarters are usually only provided for the supervisory personnel.

2.1.2 Formation Evaluation

The operator is constantly evaluating the 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.[1]

2.2 DEVELOPMENT DRILLING

Development of the oil and gas reservoirs involves drilling of wells into the reservoirs to initiate hydrocarbon extraction, increase production or replace wells that are not producing on existing production sites. Development wells tend to be smaller in diameter than exploratory wells because, since the geological and geophysical properties of the producing formation are known, drilling difficulties can be anticipated and the number of workovers during drilling minimized. In the Gulf of Mexico coastal region, development wells average 8,500 feet in depth. In Alaska, development wells average 12,000 feet in depth.[2]

Different types of drilling rigs are used during development drilling, depending on the location of the producing reservoir. In the Gulf of Mexico region, mobile drilling units are used for development drilling as well as exploratory drilling. In the Cook Inlet region of Alaska, the two most commonly used types of drilling rigs are the platform rig and the mobile drilling units. Development wells are often drilled from fixed platforms in Cook Inlet because once the exploratory drilling has confirmed the existence of extractable quantities of hydrocarbons, a platform is constructed at that site for drilling and production operations. On the North Slope, development drilling is done from both dedicated and mobile drilling rigs. The drilling rig and all the associated equipment are housed and insulated to protect them from the harsh weather conditions.

To extract hydrocarbons from the reservoir effectively, several wells may be drilled into different parts of the formation. A special drilling technique, termed "directional drilling", has been developed to penetrate different portions of a reservoir from a fixed location directly below the rig. Directional drilling involves drilling the top part of the well straight and then directing the wellbore to the desired location in nonvertical directions. 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. Directional drilling is commonly practiced in the Cook Inlet and on the North Slope. Although not commonly practiced in the Gulf of Mexico, some operators employ this drilling method to minimize environmental impacts (e. g., in protected wetlands) and to speed up the well permitting process by using existing drilling pads.[3]

Horizontal drilling is a specialized directional drilling technique that maximizes the length of penetration in the pay zone (hydrocarbon reservoir) by horizontally drilling through the pay zone, thus maximizing the fluid extraction from a single production string.[4] Horizontal drilling is also referred to as drilling under balance as there is no pressure equilibrium between the formation and the bore hole as in conventional drilling. The formation pressure is greater than the bore hole pressure (a blow out condition) but special surface equipment controls the down hole pressure differentials preventing a blow out.

Horizontal drilling is occasionally practiced in coastal environments when the geometry of the reservoir makes horizontal drilling the most economical method of extracting the hydrocarbon reserves.[4] It should be noted that horizontal drilling is not practiced as a means of minimizing impacts to the surface environment. Also, horizontal drilling is associated with greater volumes of waste than vertical drilling because the length of the borehole is greater and the drilling time is longer.

2.2.1 Well Drilling

The process of drilling 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 the drilling rig to a few hundred feet below the surface. The conductor casing, which is approximately two feet in diameter, is either hammered, jetted, or placed into the ground depending on the composition of the ground. If the composition of the ground is soft, the conductor casing can be hammered into place or lowered into a hole created by a high-pressure jet of water. In areas where the ground is composed of harder material, the casing is placed in a hole created by a large-diameter rotating drill bit.

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. Cement is pumped into the space between the casing and the hole wall to secure the casing in place. Each new casing string must be smaller in diameter than the previous string to allow for installation. This process of drilling and adding sections of casing is continued until final well depth is reached.

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 through the nozzles in the drill bit with great speed and pressure. The jets of fluid 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 space between the drill string and the casing, called the annulus, where cuttings, silt, sand, and any gases 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 separation process which typically includes a shaleshaker, desilter, and desander and sometimes centrifuges. Figure IV-1 presents a schematic flow diagram of the fluid circulation system. Some of the drilling fluid remains with the cuttings after solids separation.[5,6]

Drilling fluids function to cool and lubricate the bit, stabilize the walls of the borehole, and maintain equilibrium between the borehole and the formation pressure. The drilling fluid must exert a higher pressure in the wellbore than exists in the surrounding formation, to prevent formation fluids (water, oil, and gas) from entering the wellbore which will otherwise 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 pressure and the well flows uncontrolled. To prevent well blowouts, high pressure safety valves called blowout preventers (BOPs) are attached at the top of the well.

Since the formation pressure varies 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. One purpose of setting casing strings is to accommodate different fluid pressure requirements at different well depths. Other properties of the drilling fluid, such as lubricity, gel strength, and viscosity, must also be controlled to satisfy changing drilling conditions. The fluid must be replaced if the drilling fluid cannot be adjusted to meet the downhole drilling conditions. This is referred to as a "changeover."

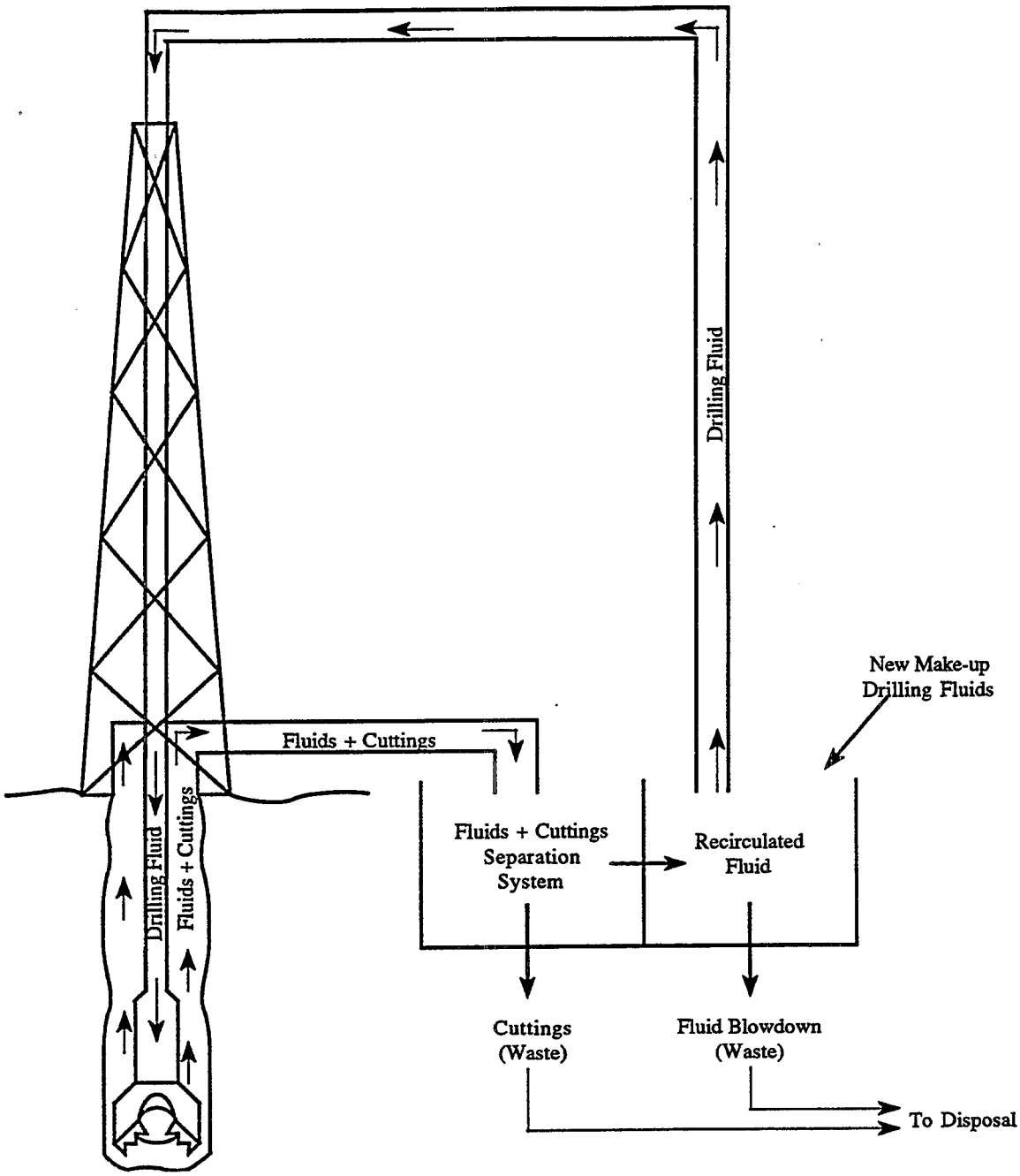


Figure IV-1
Typical Drilling Fluids Circulation System

The solids control system is necessary to maintain constant fluid properties and/or change them as required by the drilling conditions. The ability to remove drill solids from the drilling fluid, referred to as "solids removal efficiency," is dependent on the equipment used and the formation characteristics. High solids content in the drilling fluid, or a low solids removal efficiency, results in increased drilling torque and drag, increased tendency for stuck pipe, increased fluid costs, and reduced wellbore stability. More detailed discussion on solids control systems can be found in Section VII.

Operators control the solids content of the drilling fluid by adding fresh fluid to the circulating fluid system to reduce the percentage of solids and to rebuild the desired rheological properties of the fluid. A disadvantage of dilution is that the portion of the fluid removed, or displaced, from the circulating system must be stored or disposed. Also, greater quantities of fluid additives are required to formulate the replacement fluid. Both of these add expenses to the drilling project.

Most drilling fluid fluids are water-based, although oil-based systems are used for specialized drilling projects and more recently synthetic based drilling fluid systems are becoming more popular. In the 1970's, drilling fluids were mostly oil-based. The trend away from oil-based fluids is due to: 1) the BPT limitations which prohibit the discharge of drilling wastes if "free oil" is detected; and 2) advancements in water-based fluids technology. Until recently, only oil-based fluids 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 fluids with similar properties to that of oil-based fluids 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 fluid system and to aid in freeing stuck drill pipe. In the past, diesel oil was solely used to enhance lubricity and to free stuck pipe because of its properties and its availability at a drilling site. More recently, mineral oil and synthetic lubricants have replaced diesel oil. 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 fluid 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 fluid system.[7]

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, fluid changeover, and displacement by cement and casing. Fluid generation is the greatest at well completion because the entire fluid system must be removed from the hole and the fluid tanks. Some of the constituents in the drilling fluid can be recovered after completion of the drilling program, either at the rig or by the supplier of the drilling fluid. Where drilling is continuous, such as on multiple-well platforms, the fluid can be conditioned and reused from one well to another.[8]

3.0 PRODUCTION ACTIVITIES

This section describes the activities and processes associated with producing hydrocarbons from the formation and processing the production fluids. The activities and processes described in this section are well completion, fluid extraction, fluid separation, well treatment, and workover.

3.1 COMPLETION

After confirmation of a successfully producing formation, the well must be prepared for hydrocarbon extraction, or "completion." Completion operations include the setting and cementing of the production casing, packing the well and installing the production tubing. During the completion process equipment is installed in the well which allows hydrocarbons to be extracted from the reservoir. Completion methods are determined based on the type of producing 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.[9,10]

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. Figure IV-2 presents schematic diagrams of the four most common completion methods used for different formation types. All completion methods consist of four steps: wellbore flush, production tubing installation, casing perforation, and wellhead installation.

Completion fluids are used during the completion phase to clean the wellbore or for pressure maintenance until production is initiated. The initial wellbore flush consists of a slug of water that is injected into the casing. These fluids are considered cleaning or pre-flush fluids and can be circulated

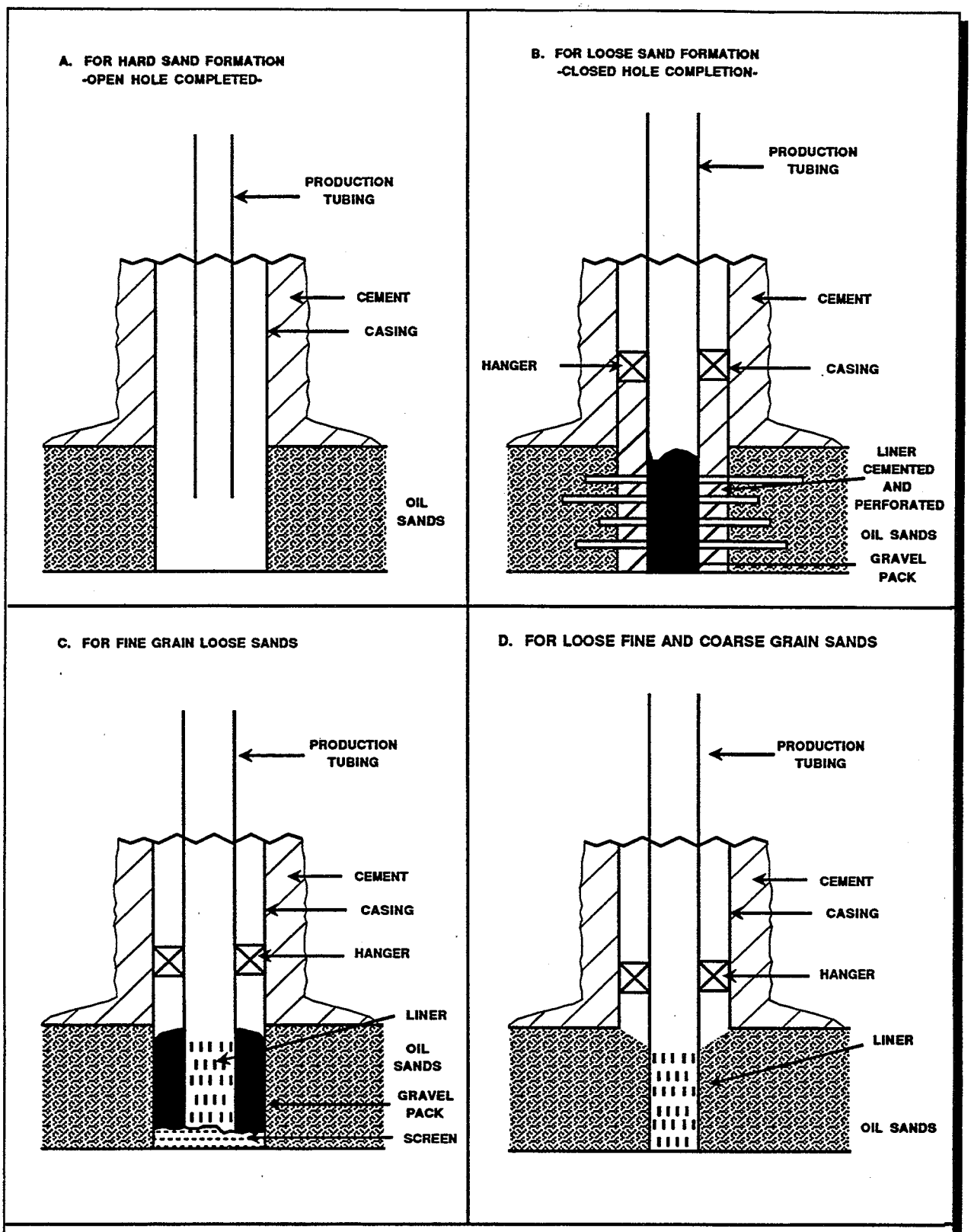


Figure IV-2
Typical Completion Methods

and filtered many times to remove solids from the well and to minimize the potential of damage to the formation.[11] 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.

During the second step of well completion, production tubing is installed inside the casing using a packer which is placed at or near the end of the tubing. The packer which consists of pipe, gripping elements, and sealing elements, is made of rubber. The purpose of the packer is to keep the tubing in place by expanding to form a pressure-tight seal between the production tubing and the well casing.[1,12] The packer seals off the annular space and forces the reservoir fluids to flow up through 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. These fluids are used to provide long-term protection against corrosion. Packer fluids are typically mixtures of a polymer viscosifier, a corrosion inhibitor, and a high concentration salt solution.[13] Packer fluids remain in place and may be removed during workover operations.[14]

After the production tubing is secured in place with packers, it must be perforated to allow the hydrocarbons to flow from the reservoir into the wellbore. Perforation may be accomplished with a special 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.[1,12]

The final step in well completion is the installation of the "Christmas tree," a device that controls the flow of hydrocarbons from the well. When the valves of the Christmas tree are initially opened, the completion fluids remaining in the tubing are removed and flow of fluids from the formation begins.

3.2 Fluid Extraction

The fluid produced from oil reservoirs consists of oil, natural gas (referred to hereafter as gas), and produced water. Gas wells may produce dry gas, but usually also produce varying quantities of light hydrocarbon liquids (known as natural gas liquids or condensate) and produced water. Produced 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 pressure 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 pressure in the reservoir decreases and additional pressure must be added to the reservoir to continue production of the fluids. Additional pressure can be provided artificially to the reservoir by various mechanisms at the surface. The most common methods of artificial lift, or secondary recovery, are the following three: (1) gas lift, which is the 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 water into the reservoir to maintain formation pressure that would otherwise drop as the withdrawal of the formation fluids continue; 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 wellhead.

3.2.1 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.

3.3 FLUID SEPARATION

As they surface, the gas, oil, and water are separated for further processing and sale, and for treatment. The gas, oil, and water are separated in a single vessel or, more commonly practiced, in a series of vessels. 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 vigorously mix the oil and the water. 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 aid in the separation of emulsified liquids. The produced fluid separation system is a series of separation vessels arranged in a multistage separation process. Figure IV-3 presents a flow diagram of a typical produced fluid separation system.

The first stage of the produced fluids separation system consists of two-phase separators, or in some cases of three-phase separators. 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. For gas wells the two-phase separators may generate light hydrocarbons that condense out as the pressure and temperature drop. These light hydrocarbons (known as gas liquids or condensate) can be processed and sold separately at a higher price than oil, or most commonly combined and processed with the oil. In a two-phase separator, the gas is separated from the liquid products. The separated gas is dehydrated in a glycol dehydrator and then used for electrical power generation, gas lift operations, or sold via pipeline. The liquid products free of gas are further treated in the oil treatment unit. A schematic of a two-phase separator is presented in Figure IV-4.

A three-phase separator, often referred to as bulk separator, is sometimes used instead of a two-phase separator to separate the produced fluids into gas, oil and water. The gas stream is drawn off the top of the vessel and further treated in a glycol dehydrator. The oil stream is drawn off the middle and piped to the oil treatment system for further processing. The water stream is drawn off the bottom and is piped to the water treatment system for further treatment. A schematic diagram of a bulk separator in presented in Figure IV-5.

Following the gas separation, the oil-water mixture is directed to the oil treatment system for separation. The oil treatment system consists of free-water knock out (FWKO) tanks, heater-treaters, and/or gun barrels. These types of oil-water separation systems may be used singly or in various combinations. FWKOs are often used to remove free water (water that is not in emulsion) from the influent to heater-treaters in order to reduce the amount of fluids to be heated, thus reducing the energy needed to heat the fluids.

Whether or not a phase separator is used, if oil-water emulsions are present heater-treaters are required. Heat and/or emulsion-breaking chemicals are almost always necessary to break the oil-water emulsions to assure low water content in the oil product (most pipelines have water content limitations on the oil that can be transported). Heater-treaters are designed to remove emulsified water from the product oil through gravity separation aided by heat and/or the addition of chemicals to enhance and accelerate separation. Oil is drawn off the top of the heater/treater unit and sent to the oil product vessel for storage. Water is removed from the bottom of the heater/treater unit and is either piped to the gun barrel or the water treatment unit. A schematic diagram of a heater-treater is presented in Figure IV-6.

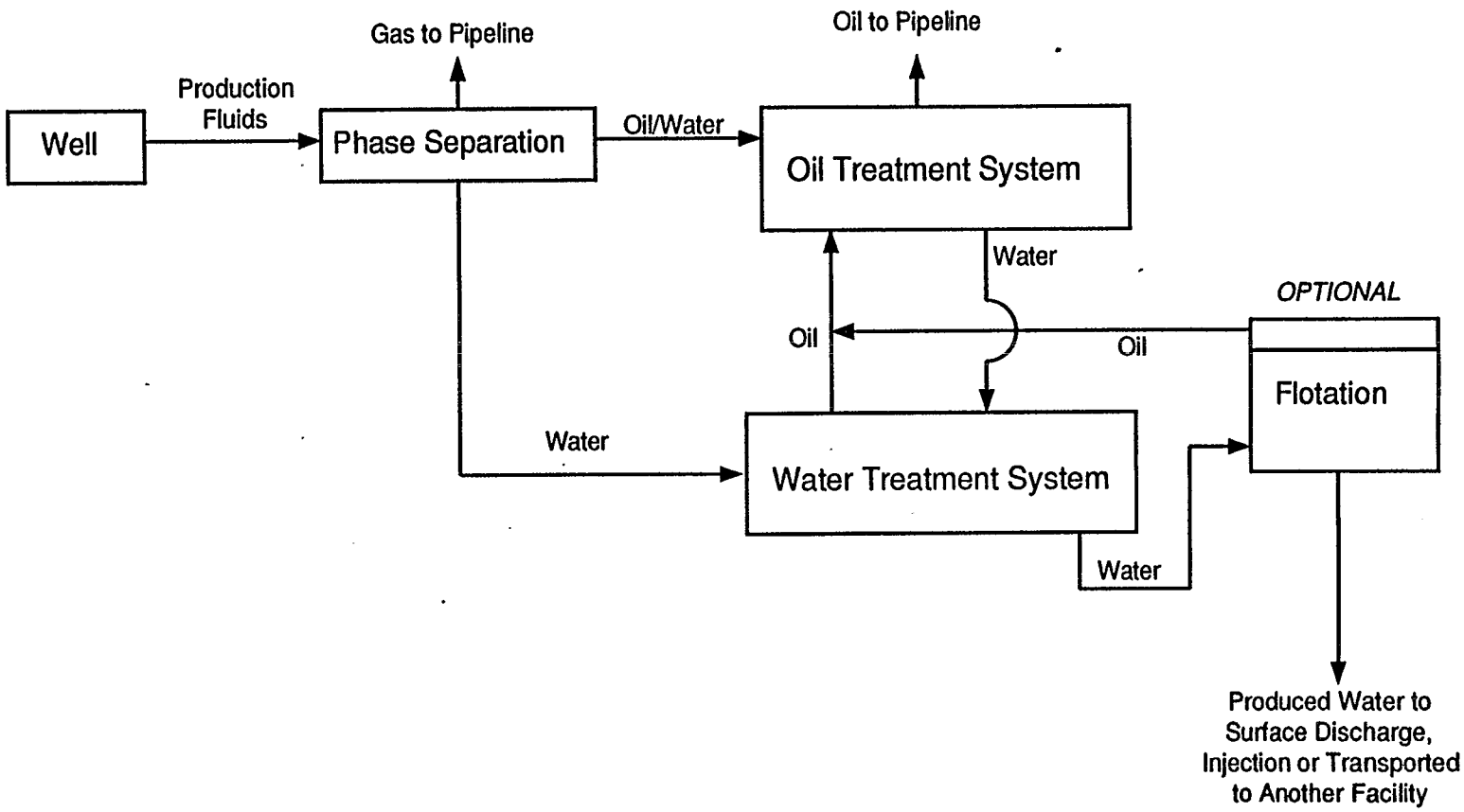
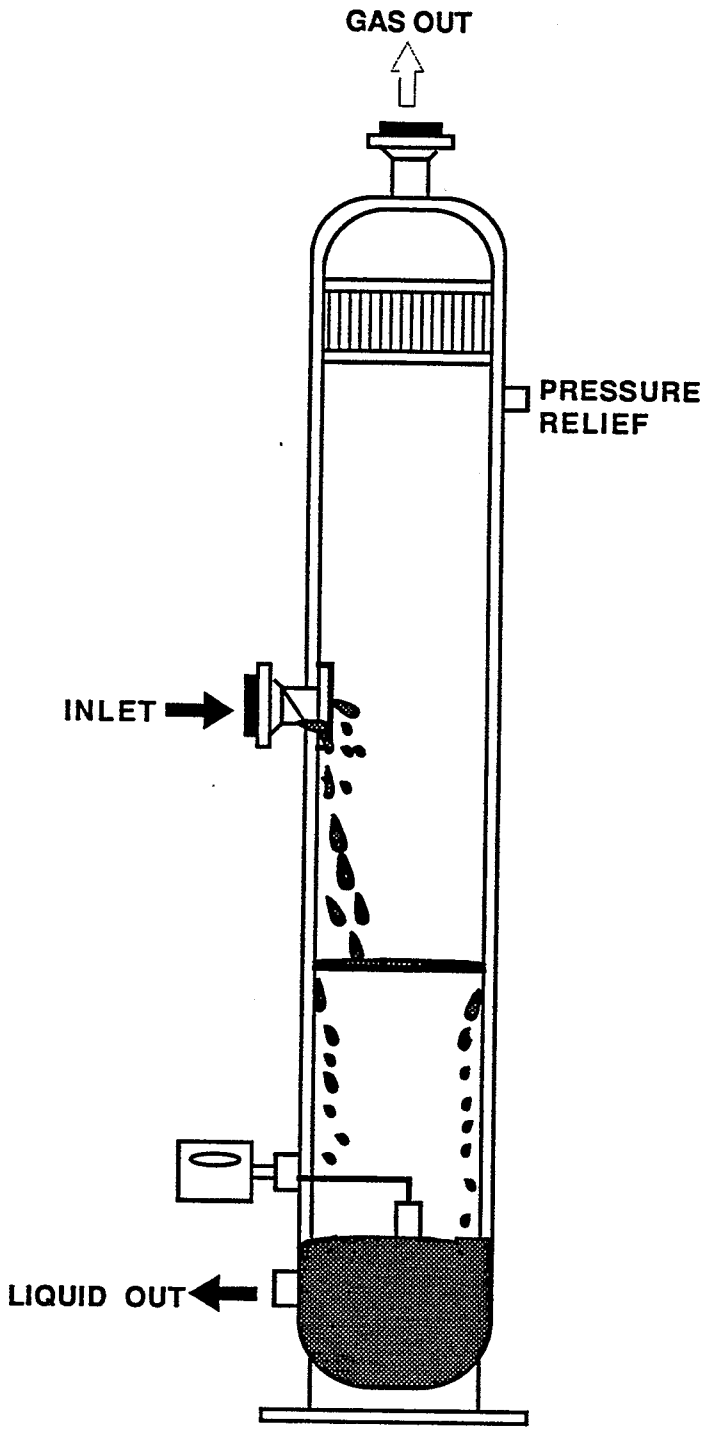


Figure IV-3
Produced Water Treatment System



Source: Smith Industries, Inc., 1980

Figure IV-4
Two-Phase Separator

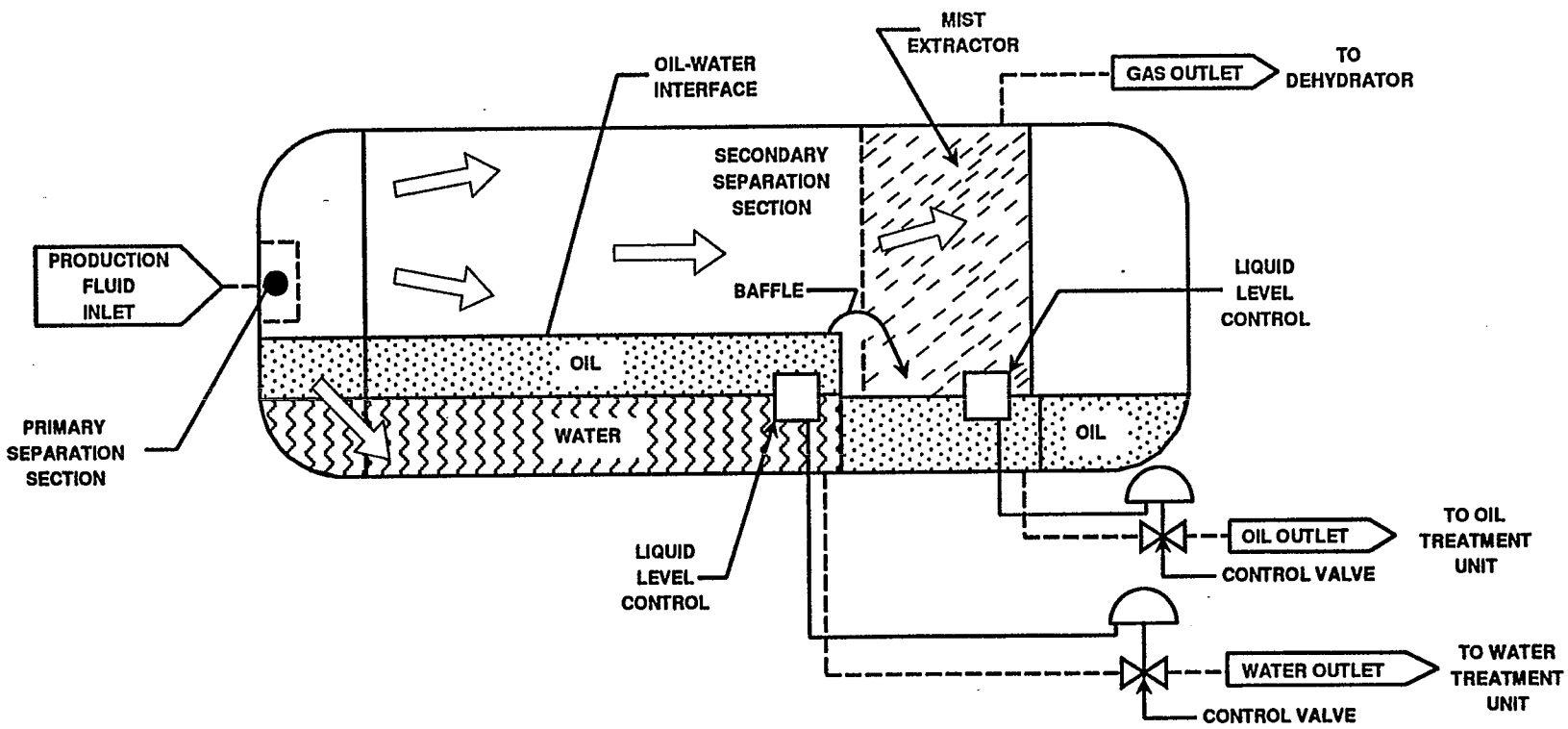


Figure IV-5
Three-Phase Separator

Gun barrels are sometimes used as a final oil-water separation process. The name refers to the fact that these units are usually configured as tall vertical tanks to allow for gravity flow of oil to the oil stock tanks. Figure IV-7 presents a schematic diagram of a gun barrel. A gun barrel is essentially a tall settling tank which utilizes gravity separation, sometimes assisted with heat and/or chemicals to further break the oil water emulsion. The water is piped to the water treatment unit.

The water treatment system receives produced water from the oil treatment unit. Water treatment usually consists of one or more large settling tanks, also called skim tanks, which utilize gravity to remove any residual suspended oil droplets from the produced water. This process is sometimes aided with the use of treatment chemicals such as surfactants.

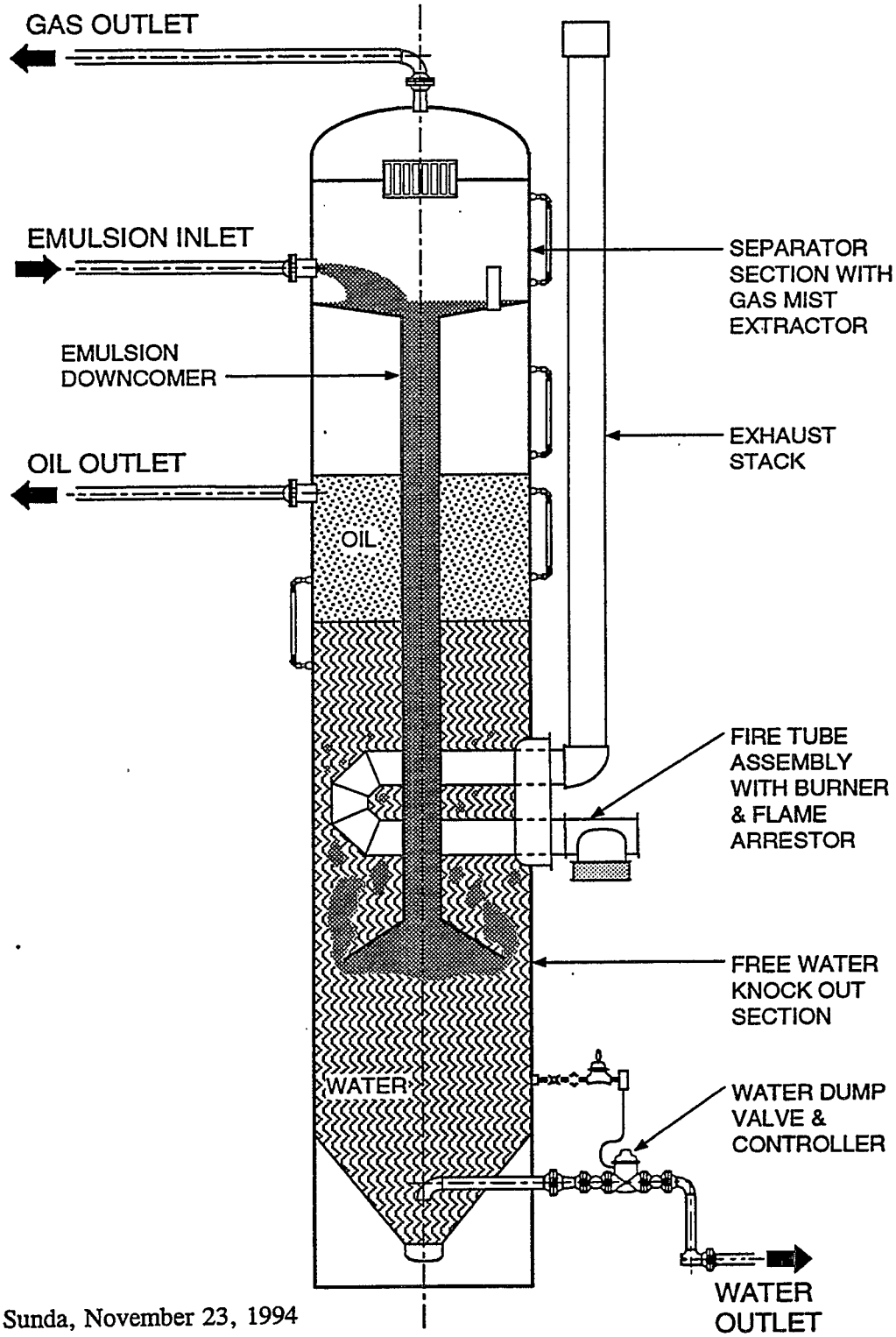
An oil layer accumulates in the top portion of the tank. Oil is periodically removed from the top of the tank and is piped back to the oil treatment unit. Water is drawn off the bottom of the vessel and is either discharged to surface waters if it meets the BPT oil and grease limitations, injected underground or transported to another site for disposal. In addition to the skim tank, the water treatment unit may include gas flotation and coalescers. A detailed discussion of these other produced water treatment technologies can be found Section VIII.

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 hydrocarbon products in the produced water treatment system.

3.4 WELL TREATMENT

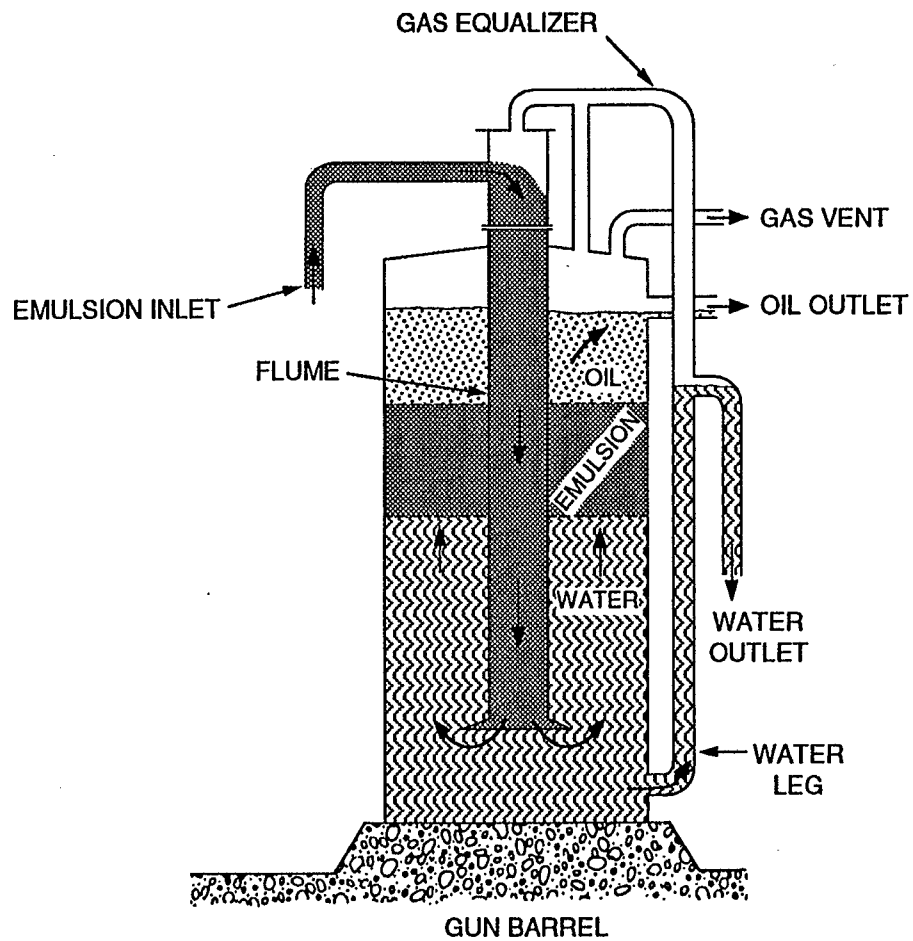
Well treatment is the process of stimulating a producing well to improve oil or gas productivity. There are two basic methods of well treatment: hydraulic fracturing and acid treatment. The specific method is chosen based on the characteristics of the reservoir, such as type of rock and water cut.[11] 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, and acid treatment is performed on formations of limestone or dolomite.[10,12]

Hydraulic fracturing injects fluids into the well under high pressure, approximately 10,000 pounds per square inch gage (psig). This causes openings in the formation to crack open, increasing their size



Source: Sunda, November 23, 1994

Figure IV-6
Verticle Heater - Treater



Source: API, 1983

Figure IV-7

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.[10,18] Hydraulic fracturing is rarely done in Gulf of Mexico operations because the unconsolidated sandstone formations in the region do not require fracturing.

Acid stimulation is performed 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.[10]

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 paraffins 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.[19]

3.5 WORKOVER

Workover operations are performed on a well to improve or restore productivity, repair or replace downhole equipment, evaluate the formation, or abandon a well. 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. Workover operations include well pulling, stimulation (acidizing and fracturing), washout, reperforating, reconditioning, gravel packing, casing repair, and replacement of subsurface equipment.[10,20,21] Responses to EPA's 1993 survey of coastal oil and gas facilities (discussed in Section V) indicated that workovers or treatment jobs occur approximately once per year.[2] The EPA survey of coastal operators is described in detail in Section V.

The four general classifications of workover operations are pump, wireline, concentric, and conventional[22], Workovers can be performed using the original derrick if drilled from a drilling platform, a mobile workover rig, or by wireline. The operation is begun by using a workover fluid to force 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 required operations.

4.0 PRODUCTION AND DRILLING: CURRENT AND FUTURE

4.1 INDUSTRY PROFILE

Coastal oil and gas extraction activities currently exist in the Gulf of Mexico coastal regions of Texas, Louisiana, Alabama and Florida, in Long Beach Harbor, California, and in Cook Inlet and the North Slope, Alaska. Because of dramatic geological, topographical and climatological differences between these areas, production and drilling activities in these areas are equally as varied. In addition to the geographic location, several other factors affect the operations of this industry. These factors include whether oil, gas or both oil and gas are produced, whether the producing well(s) are located over water and wetlands or on land, the depth of water, whether it is a single producing well or a cluster of single wells, and whether it is a multi-well platform. The coastal oil and gas industry is described below in terms of production and drilling activity, as well as location and operational differences, where appropriate.

In general, the same factors that affect the operations of the producing wells will also affect the configuration of the separation/treatment facilities (production facilities) that service these wells. Production facilities consist of the treatment equipment and storage tanks that process the produced fluids. Production facilities may be configured to service one well, or as central facilities (also known as tank batteries or gathering centers) to service multiple satellite wells. Production facilities are also configured to service a single multi-well platform, or to service multiple platforms. A multiple-well producing platform is a fixed structure usually located in deep waters, with least two producing wells that have the same surface location.[23]

Coastal production facilities can be located over water or on land. Production facilities located over water exist in generally two types of configurations: 1) individual deep water multi-well platforms or 2) central facilities supported on barges or wooden or concrete pilings that service multiple satellite wells in shallow water. Production facilities on land may service satellite wells in any combination of locations.

Depending on operational preference or regulatory requirements, many of the coastal production facilities do not discharge produced water. While these facilities are discussed in the industry profile,

they would not incur costs due to this rulemaking. Table IV-1 summarizes the number of producing wells and annual drilling activities for the coastal regions of the United States and the number of producing facilities that would incur costs due to this rulemaking, by geographic locations.

The production facilities listed in Table IV-1 are discharging produced water in the coastal areas of Texas (TX), saline and brackish coastal waters of Louisiana (LA), and the Cook Inlet of Alaska. All coastal production facilities in Mississippi (MS), Alabama (AL), Florida (FL), the North Slope, and California inject all of their produced water either for disposal or for waterflooding. There are no discharges of drilling fluids and cuttings from coastal operators except for those in Cook Inlet. The volumes and locations of discharges are discussed in more detail in Sections VIII and IX.

4.2 CURRENT PRODUCTION OPERATIONS

4.2.1 Gulf of Mexico

Multi-well platforms, such as those found in the Gulf of Mexico offshore area, are not commonly found in the Gulf coastal area. Based on an earlier mapping effort of all oil and gas wells, EPA determined that there are only four structures owned and operated by four different operators in the coastal Gulf of Mexico region that can be classified as multi-well platforms.[23] In addition, many single wellheads are located throughout coastal waters, serviced by gathering centers located on-land or on platforms.

Production facilities in the Gulf of Mexico can be divided into two different types of structures: those located on land or fill material and those located over water or wetlands. Production facilities located on land and fill material in wetlands and shallow water usually utilize earthen berms around storage tanks and equipment to contain spills. Production facilities located over water and protected wetlands can be located on diked concrete platforms supported on wooden or concrete pilings. In deeper waters such as in open bays, steel jacketed pilings or offshore type platforms may be necessary. Some of the older facilities have been constructed using wooden platforms or pilings. Another configuration for facilities over water is the use of barges to support equipment and for use as storage tanks. Although there are some exceptions, in most cases those located on land can be accessed by car or truck (land-access) while those facilities located over water must be accessed by boat or barge (water-access). This distinction is important because when estimating regulatory compliance costs and impacts as described in Sections X and XI.

TABLE IV-1

PROFILE OF COASTAL OIL AND GAS INDUSTRY

Coastal Location	Region	No. of Producing Wells (1992)	No. of Production Facilities (1992)	No. of Discharging Production Facilities (1992)	No. of Operators (1992)	No. of Operators Discharging After July 1996	No. of Production Facilities Discharging After July 1996	No. New Source Production Facilities per Year[a]	No. New Wells Drilled per Year	
									All Well Types	New Development Wells Only
Gulf of Mexico	TX and LA	4,675[b]	853[b]	325[c]	270 - 435[b] (162 dischargers[c])	122	216[c]	6[d]	686[e]	187[e]
	AL and FL	56[f]	NE[g]	0[f]	NE[g]	0	0[f]	1[h]	NE[g]	5-7[f]
Alaska	Cook Inlet	237[i,j]	8[i]	8[i]	5[k]	5[k]	8[i]	0[l]	8[m]	5[m]
	North Slope	2,085[i]	11[n]	0[i]	3[k]	0	0[i]	0[o]	161[p]	NE[g]
California	Long Beach Harbor	586[f]	4[f]	0[f]	1[f]	0	0[f]	0[q]	NE[g]	6-7[f]
TOTALS	--	7,639	876	333	279 - 444	127	224	7	855	203 - 206

Notes and Ref.s:

(a) This column reflects the number of new sources which may be different than new facilities (see definition of "new sources" in Section 3).
(b) Jones, Sept. 26, 1994 (24)
(c) McIntyre, December 30, 1994 (25)
(d) Stralka, July 12, 1994 (26)
(e) SAIC, Jan. 31, 1995 (2)
(f) Wiedeman, Sept. 6, 1994 (27)
(g) NE = Not Estimated
(h) See discussion in Section 4.3.2.
(i) Wiedeman, Aug. 31, 1994 (28)
(j) Hanchera, April 12, 1994 (29)
(k) SAIC, Jan. 6, 1995 (30)
(l) See discussion in Section 4.3.2.
(m) Appendix X-1 (Worksheet 2). Includes only development and recompletion wells.
(n) See discussion in Section 4.2.5.
(o) Erickson, Aug. 11, 1994 (31)
(p) Erickson, Jan. 24, 1995 (43)
(q) See discussion in Section 4.3.2.

An analysis of the EPA 1993 Questionnaire database indicates that, of the estimated 530 coastal production facilities in the Gulf of Mexico region, 182 (or 34.4%) are land-accessed facilities and 348 (or 65.6%) are water-accessed facilities (see discussion in Section XII.3.1.1).[a] Of the total number of production facilities in Louisiana and Texas, approximately 60% inject the produced water.[2] Also, of the total volume of miscellaneous wastes generated in Texas and Louisiana, 40% is currently injected or land disposed.[2] Based on state discharge monitoring records and the discharge compliance schedules implemented in Louisiana, EPA determined that of the total coastal production facilities in Louisiana and Texas, 216 will continue discharging produced water after August 1, 1996.[23]

Table IV-2 summarizes information on existing coastal oil and gas production facilities in the Gulf of Mexico. Detailed information on the 216 discharging facilities is presented in Appendix XI-3.

TABLE IV-2

OIL AND GAS PRODUCTION FACILITY INFORMATION FOR THE COASTAL TEXAS AND LOUISIANA

Type of Facility	No. Production Facilities[a]	Average Volume Produced Water per Production Facility (bpd)	Average Oil Production per Production Facility (bpd)	Average Natural Gas Production per Production Facility (Mcfd)
Discharging Facilities	216[b]	2,265[b]	245[c]	2649[c]
All Facilities	853[d]	1565[c]	2003[e]	2179[c]

[a] The facility that accepts hydrocarbon fluids from one or more wells and separates them into oil, gas, and produced water is termed a "Production Facility."
[b] McIntyre, December 30, 1994 (25)
[c] SAIC, January 31, 1995 (2)
[d] Jones, September 26, 1994 (24)
[e] Henderson, August 22, 1994 (32)

4.2.2 Mississippi, Alabama, Florida

According to the Mississippi State Oil and Gas Board, there are currently no coastal wells operating in the wetlands of Mississippi. None are planned in the foreseeable future. The only Mississippi oil and gas activity is onshore some 6 miles inland.[33]

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[a] The number 530 was the actual result from the 308 Questionnaire responses. This value was extrapolated to 853 as shown in Table IV-1 to reflect actual industrial activity.[24] However, for determining percentile assumptions such as the number of water-based versus land-based facilities, the actual result of 530 was used in estimation calculations.

Alabama coastal oil and gas activity consists of approximately 15 producing gas wells located in Mobile Bay.[34] Approximately 3-5 new wells are drilled in Bay each year.[35] All produced waters from the Bay's activities are injected for disposal in UIC Class II wells located onshore. All drilling fluids and cuttings are also transported to shore for disposal at onshore commercial disposal facilities.

In Florida, approximately 41 producing oil and gas wells currently exist in coastal areas on the western side of the state.[36] Average drilling rate is approximately 2 new wells per year. All produced water is injected in Class II UIC wells, primarily for disposal although some is also injected for waterflooding. All drilling fluids are either reused, annularly injected, or left in a dry wellbore. Drill cuttings are either disposed of in reserved pits or hauled off site to landfills.

4.2.3 California

The California coastal oil and gas industry currently exists on four man-made islands in Long Beach Harbor behind the barrier islands in San Pedro Bay. The facilities on these islands are operated by THUMS, a consortium of five oil and gas operating companies (Texaco, Humble (now Exxon), Union, Mobil and Shell). On these four islands operated by THUMS, approximately 586 wells are producing as of 1993.[37] Six to seven new wells are drilled each year. All produced waters from these operations are injected, primarily for waterflooding. No discharges occur from drilling fluids and cuttings. Closed-loop solids control technology is employed by these operations. All dewatered solids are sent to an onshore landfill. The water from the solids dewatering equipment is allowed to settle (on-site) and the decant is directed to the on-site produced water treatment system. Plans are to begin using a grinding and injection operation in 1994 for drilling waste disposal. The ground wastes will be injected into a UIC well on site.

4.2.4 Cook Inlet

All the coastal oil and gas production is currently confined to the Upper portion of Cook Inlet. Oil and gas is produced from multi-well platforms that are similar in construction to offshore platforms. Table IV-3 presents information on existing oil and gas production facilities in Cook Inlet as of August 1993. There are four major operators in Cook Inlet: Unocal Corp., Marathon Oil Co., Phillips Petroleum Co., and Shell Western E&P Inc. In addition, ARCO and Phillips Petroleum are together developing a new discovery, the Sunfish field, which is located in the North Upper Cook Inlet. However, this field has not been brought into production as of this writing. The total current oil

production in Cook Inlet is about 34,700 barrels per day (bpd) and the total gas production is 330,000,000 cubic feet per day (cfd).[28]

There are a total of 15 multi-well platforms in Cook Inlet, 12 of which were productive as of August 1993. Five of the fifteen platforms separate and treat the produced water on the platform before it is discharged overboard. The remaining eight platforms pipe the production fluids to three shore-based separation/treatment facilities. Of the three shore-based facilities, two discharge treated produced water from the facility, and the third sends its produced water back to one of the platforms for discharge. These three facilities treat and discharge 95% of the produced water generated from all platforms in Cook Inlet (see Table IV-3).

As of August 1993, Unocal owned and operated eight platforms in the Trading Bay, Granite Point, and Middle Ground Shoal fields, which included a total of 135 oil producing wells, 22 service wells used to inject seawater, and 4 gas producing wells. These platforms produced a total of 21,300 bpd of oil in 1993. The gas produced by all Unocal-owned wells is not sold and is only used to power equipment on platforms. Four of the platforms are located in the Middle Ground Shoal field and separate and treat the production fluids on the platform. Oil is piped to shore for sale, while the produced water, which totals 1,690 bpd from these four platforms, is discharged overboard. The remaining four platforms are located in the Trading Bay and the Granite Point fields and pipe the production fluids to two shore-based facilities for separation and treatment. All produced water from these platforms, totaling 84,090 bpd, is discharged to Cook Inlet after treatment at the onshore facilities.

Marathon owns and operates four platforms in the Trading Bay and Granite Point fields, including a total of 38 oil producing and service wells (undistinguished in the data source), and 22 gas producing wells. Only two of the four platforms are currently producing oil and gas. Of the two platforms currently shut-in, plans are to initiate gas production on only one platform. The total produced water flow from the two active platforms averages 43,972 bpd. All the production fluids are piped to either the Granite Point or the Trading Bay shore-based facilities for separation and treatment. Produced water is discharged to Cook Inlet after treatment.

Shell Western E&P owns and operates two platforms in the Middle Ground Shoal field, including a total of 46 oil producing and service wells and one gas producing well. The gas produced is not sold and is only used to power equipment on platforms. The total produced water flow from the two platforms is 3,300 bpd. All production fluids are piped to the East Forelands shore-based facility for

TABLE IV-3

OIL AND GAS PRODUCTION FACILITIES IN COOK INLET REGION AS OF AUGUST 1993[a]

Facility Name	Operator	Total No. Available Slots	No. Oil & Service Wells	No. Gas Wells	Oil Production (bpd	Gas Production (cfd)	Seawater Waterflooding Vol. (bpd)	Avg. Prod. Water Vol. (bpd)	PW Disch. Location
PLATFORMS									
King Salmon	Unocal	24[b]	19[c]	1	4,100	Platform Use	40,000[b]	40,300	Trading Bay
Monopod	Unocal	32[b]	29 oil; 2 service	0	2,000	Platform Use	6,000[b]	4,800	Trading Bay
Grayling	Unocal	48[b]	24 oil; 10 service	2	7,000[c]	Platform Use	45,700[b]	37,000	Trading Bay
Granite Point	Unocal	48[b]	11 oil; 6 injection	0	4,300	Platform Use	5,200[b]	300	Granite Point
Dillon[d]	Unocal	32[b]	10 oil; 3 service	0	0	0	5,000[b]	0	Platform
Bruce[d]	Unocal	32[b]	11 oil; 8 injection	0	600	Platform Use	0[b]	160	Platform
Anna[d]	Unocal	32[b]	20 oil; 8 injection	0	2,300	Platform Use	0[b]	1,500	Platform
Baker[d]	Unocal	33[b]	11 oil; 4 service	1	1,000	Platform Use	0[b]	30	Platform
Dolly Varden	Marathon	48[b]	24[c]	1	6,500	Platform Use	39,000[b]	35,672	Trading Bay
Spark[d]	Marathon	12[b]	5(shut-in)	9(shut-in)	0	0	0[b]	0	Platform
Steelhead	Marathon	48[b]	3[c]	11	1,800	165,000,000	11,500[b]	8,300	Trading Bay
Spurr	Marathon	12[b]	6[c](shut-in)	1(shut-in)	0	0	0[b]	0	Granite Point
SWEPI "A"	Shell Western	32[e]	22[c]	1	2,700	Platform Use	5,566[e]	1,500	E. Foreland
SWEPI "C"	Shell Western	24[e]	24[c]	0	2,400	Platform Use	5,774[e]	1,800	E. Foreland
Tyonek "A"[d]	Phillips	--	0	12	0	165,000,000	0	170	Platform
ONSHORE FACILITIES									
Granite Point	Unocal	--	--	--	--	--	--	300	Spark Platform
Trading Bay[d]	Marathon	--	--	--	--	--	--	121,243	Outfall
E. Foreland[d]	Shell Western	--	--	--	--	--	--	3,300	Outfall

[a] All data in this table appear in both Wiedeman, August 1, 1994 and Hanchera, 1994, with the exceptions cited in notes "b" and "e" below. (28)(29)
[b] These data points are provided in Hanchera, 1994. (29)
[c] Data sources did not distinguish oil wells from service or injection wells for these platforms. Therefore, these wells were assumed to be producing oil wells.
[d] Facilities directly discharging produced water to Cook Inlet.
[e] These data points are provided in Erickson, April 18, 1994. (38)

separation and treatment. Produced water is discharged to Cook Inlet after treatment.

Phillips Petroleum operates one platform in the North Cook Inlet field, including 12 gas producing wells. All produced water generated is treated at the platform and discharged overboard.

4.2.5 North Slope

Table IV-4 summarizes the most current information regarding oil and gas production on the North Slope. As can be seen from Table IV-4, there are a total of 2,085 oil, gas, and service wells on the North Slope. The Prudhoe Bay field is the largest production field on the North Slope, accounting for about 71% of the total oil production on the North Slope. The two major operators in Prudhoe Bay, ARCO and BP Exploration (BPX), which own and operate the east side and the west side, respectively.

TABLE IV-4
OIL AND GAS PRODUCTION FACILITIES ON THE NORTH SLOPE
(Weideman, August 31, 1994)[28]

Field Name	Operator	Number of Oil, Gas, and Service Wells	Oil Production[a] (bpd)	Average Produced Water (bpd)	Number of Gathering Centers
Prudhoe Bay	ARCO&BPX	1,159	1,126,000	1,233,000	6
Kuparuk	ARCO	663	300,000	300,000	3
Endicott[b]	BPX	85	115,000	80,000	1
Lisburne	ARCO	86	30,000	8,000	1
Milne Point	Conoco[c]	91	19,000	11,000	1
West Beach	ARCO	1	3,000	0	0
	Total	2,085	1,593,000	1,632,000	12

[a] Oil production data include natural gas liquid and condensate production, where applicable.
[b] Endicott field data also include production from BP's Sag Delta near Endicott.
[c] Conoco sold this field to BPX in December, 1993.

NOTE:
Point McIntyre, West Beach, and N. Prudhoe Bay production is handled in the Lisburne Production Center.

Production fluids are piped to gathering centers for separation and treatment. All the produced water from the North Slope oil production operations is injected either for waterflooding or into regulated

disposal wells. About 88% of all the produced water is injected for waterflooding. The remaining 12% is injected into Class II disposal wells.[28]

There are a total of 12 production facilities (gathering centers) on the North Slope, of which all but the Endicott gathering center are in the coastal region. The Endicott field is currently produced from two gravel islands constructed in the Beaufort Sea. The production facilities on these islands are permitted, by the Alaskan Department of Environmental Conservation, as offshore facilities. All the produced water from the Endicott field is injected for waterflooding.[28]

4.3 Future Coastal Oil and Gas Activity

4.3.1 Drilling

Coastal 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 that a total of 161 wells will be drilled in coastal areas, including development wells and recompletions.[43]

Based on drilling projections provided by the industry, EPA estimates future drilling in the Cook Inlet region to be a total of 55 wells (or 8 per year) over the 7-year period from 1996 through 2002.[39,40] The projected 55 wells include development wells and recompletions. Based on the data provided by industry, EPA estimates that 36 of the 55 wells are development and exploratory wells and 19 are recompletions. These estimates are based on industry-projected drilling activity estimates and on the number of unused slots on each platform. Projections were assumed to represent recompletions for those platforms where drilling was projected but no slots are available for new wells. Out of these 55 wells, none will be classified as "new sources" under EPA's NPDES program. This is because the projected wells will be drilled from existing platforms, or will be exploratory wells (classified as existing sources). See also Section III of this document.

EPA estimates that the current drilling rate experienced by other coastal states in 1992 (see Table IV-1) will be similar to future annual drilling rates, also. This is a conservative estimate based on projections where drilling rates are not expected to increase (due to the maturity of the Gulf coastal oil fields). Rather than project a decrease in drilling rates, EPA is estimating a linear projection.[41] Thus, out of the 686 well drilling operations performed per year in Texas and Louisiana, 187 of them will be for new production wells (as reported in the EPA's statistical analysis of the 1993 Coastal Oil and Gas Questionnaire.[2] (Note: The Questionnaire is discussed in detail in Section V).

These estimated 187 projected drilling operations per year are new sources because they are expected to be drilled over a new site. The remaining 499, which are either recompletions, sidetracks of existing wells, exploration or service wells, are not new sources because they are drilled from existing operations.

4.3.2 New Production Activity

New production activity for Louisiana and Texas is estimated to include six new facilities or separation/treatment facilities per year, based on results of the 1993 Coastal Oil and Gas Questionnaire.[26] For Alabama and Florida, EPA estimates a maximum of one new production facility per year, based on a comparison of the number of producing wells in Alabama/Florida to the number of wells in Louisiana/Texas.

No new sources are expected in Alaska. Although exploration and development of new fields will continue on the North Slope, according to the operators there are no plans to build new production facilities.[31] For new discoveries, operators on the North Slope intend to take advantage of existing separation/treatment facilities as much as possible, assuming that these facilities have sufficient capacity to handle the increased load.[31] For Cook Inlet, no new source production facilities are expected to occur in the near future. This is because, even considering the Sunfish discovery, no new platforms construction is expected.[42]

EPA knows of no plans for new islands at the THUMS facility at Long Beach Harbor, California.

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SECTION V

DATA AND INFORMATION GATHERING

1.0 INTRODUCTION

The major studies presenting information on coastal oil and gas effluents and treatment technologies EPA used to develop this proposed rule are summarized in the following sections. These include: an investigation of the underground injection of produced water and associated produced water treatment technologies; an investigation of solids control technologies for drilling fluids; an investigation of the drilling fluids and cuttings waste generation, treatment, and disposal in coastal Alaska; and an investigation of commercial non-hazardous oil and gas waste disposal facilities and technologies. In addition, a comprehensive Clean Water Act Section 308 Questionnaire of the industry was conducted to gather information to help characterize the coastal oil and gas subcategory. The questionnaire and a summary of results are described in this section. A listing is included of certain data obtained in previous studies, and used in the coastal proposed rulemaking, conducted during the development of the offshore subcategory effluent guidelines development.

2.0 INFORMATION TRANSFERRED FROM THE OFFSHORE RULE

Due to the similarities in the technologies employed and wastes generated by the offshore and coastal subcategories of the oil and gas industry, certain data generated during the offshore rulemaking effort have been utilized in the development of this proposed rule where appropriate. Those data most influential in the development of this rule, listed below, are described in more detail in the Offshore Development Document and will not be discussed further in this section.[1]

- Produced Water Characteristics for Cook Inlet

  The produced water characteristics for Cook Inlet were used as BPT-level effluent for calculating the pollutant reductions and the BCT cost test for the gas flotation and zero discharge options for Cook Inlet discharges. The data used included flow-weighted averages of the organics and zinc data in the Envirosphere report[2], BPT level effluent concentrations from the Gulf of Mexico data cited in Table XII-15 of the Offshore Development Document (where Cook Inlet data were missing for certain pollutant parameters, as discussed in Section VIII of this document), and radium data from the Alaska Oil and Gas Associations Comments submitted in response to the offshore rule, 56 FR 10664 March 13, 1991 and 56 FR 14049 April 5, 1991.[3]

- Produced Water Characteristics for Effluent from Improved Gas Flotation

  The produced water characteristics for effluent from improved gas flotation were used in the development of pollutant loadings reductions for produced water for coastal options that used the technology and for the BCT costs test. In addition, for options that included commingling miscellaneous wastes with produced water, the data were used to estimate the pollutant reductions for these wastes using improved gas flotation as described in Section VIII. These data were reported in Table XII-15 of the Offshore Development Document.

- Drilling Fluids and Cuttings Characteristics

  The concentrations of organic pollutants in mineral oil were used to calculate the pollutant loadings in drilling fluids and cuttings. The concentrations used were the averages of concentrations for three types of mineral oil presented in the Offshore Development Document, Table VII-9.

  The barium concentration used to calculate the barium loading of the discharged drilling fluid was calculated from the total pounds of barite in the drilling fluid. Based on the information provided in the Offshore Development Document, page XI-8, 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 BPT costs, the following information came from the offshore rulemaking effort:

  - Oil content in oil-based drilling fluids = 60% by volume (Offshore Table XI-3)
  - Mineral oil substitution cost = $2.00/gal (Offshore Table XI-10)
  - Drilling fluid disposal cost = $26.99/bbl (Offshore Table XI-8)
  - Cuttings disposal cost = $29.26/bbl (Offshore Table XI-8)

- Deck Drainage Characteristics

  The deck drainage characteristics from offshore operations were used to estimate the character of discharged deck drainage from coastal operations in the development of pollutant loadings reductions for deck drainage control options and for the BCT cost test. The data used were the untreated data reported in Table X-17 of the Offshore Development Document.

- Domestic Waste Characteristics

  The domestic waste characteristics from Section XVI of the Offshore Development Document were incorporated into the descriptive portions of this document and were not used in any analyses.

- Sanitary Waste Characteristics

  The sanitary waste characteristics from Section XVII of the Offshore Development Document were incorporated into the descriptive portions of this document and were not used in any analyses.

- Non-Water Quality Impacts

  The non-water quality impacts data were used to estimate the non-water quality impacts of this proposed regulation. This includes the estimation of increases in air pollution emissions and safety. The data used are a combination of information from the offshore rulemaking and supplemented with information from sources described later in this section. The data from the offshore rulemaking effort and the supplemental sources are listed below:

  - Air emission factors (Table XVIII-9 of the Offshore Development Document)
  - Equipment power and fuel requirements[4]
  - Equipment operating parameters[4]
  - Personnel casualty and injury data[5]

3.0 INDUSTRY SURVEY

A comprehensive questionnaire entitled the "1993 Coastal Oil and Gas 308 Questionnaire" was developed under the authority of Section 308 of the CWA. This questionnaire was distributed to all known coastal oil and gas operators and requested economic data and information on oil and gas waste generated, and treatment disposal methods and disposal costs for these wastes.

Prior to this, a draft of the questionnaire was reviewed by several industry trade associations, comments were considered and incorporated where appropriate. A pre-test survey was then sent to seven coastal operators in August 1992. After reviewing the pre-test results and consulting the operators, EPA made significant changes and improvements in the survey. In order to minimize the burden, the seven operators were not included in the final survey.

The 1993 Coastal Oil and Gas Questionnaire, hereafter referred to as the EPA Questionnaire, was divided into four sections. The first two sections requested information concerning the technical and financial contacts. Section 3 requested technical operating information in two parts: Section 3.1 "Production Operations," and Section 3.2 "Well Drilling Operations." Section 4 "Finances" requested financial information about the operator.

Section 3.1 "Production Operations" requested detailed information on: production data, treatment system wastewater disposal, outfall data, treatment technologies, treatment costs, injection costs, miscellaneous waste generation and disposal, miscellaneous waste disposal costs, and treatment chemical usage. Section 3.2 "Well Drilling Operations" requested detailed information on: type of well, well depth, drilling costs, type of drilling used, solids separation technologies, drilling fluid and cuttings disposal, waste handling and disposal costs, miscellaneous waste generation and disposal, miscellaneous waste disposal costs, reserve pit data, and drilling chemical usage.

The survey was designed to cover three interrelated populations. Population is a statistical term used to describe the set of all units of interest. The three populations are: (1) all operators of coastal oil and gas extraction facilities , (2) all coastal oil and gas wells, (3) all wastewater treatment facilities for coastal oil and gas extraction. There are two basic methods for conducting a survey: one is to perform a "census" which requests data on all identified units in a population, the second is to sample a subset of the population which is referred to as a "survey." The EPA Questionnaire was sent to all known coastal operators (a census) but only requested information on some of their wells (a survey).

EPA developed a list of coastal operators and their wells by combining information from several sources.[6] Three data sources were used to identify production wells and their locations. One source was the database maintained by the Petroleum Information Corporation. The database contains information on the wells completed or worked-over between 1980 and 1990. The second source was Tobin Survey Incorporated. Tobin compiles information on wells by geographic location. The third source was information supplied by the Alaska Oil and Gas Conservation Commission including wells that were active in 1991. As a result, the final list of operators to be surveyed contained 361 coastal operators and 3,623 wells.[6]

The operators were grouped into three categories; majors, large independents, and small independents. The wells were grouped into those completed before and after 1990 and those located in saline and freshwater environments. Table V-1 presents the breakdown of all 3,623 coastal wells into the categories described above. The survey was designed so that a census of all 361 operators (not including the seven pretest operators) was conducted. All operators were required to complete Section 4 "Finances." Information on all 3,623 wells was not requested. The 327 wells surveyed in the pre-test questionnaire were excluded from the survey. For 179 wells where particular situations existed that were limited in occurrence, EPA requested information on all of these wells. Such circumstances included wells located in marine wetlands (one well), wells located on platforms in the Gulf of Mexico (35 wells),

TABLE V-1

TOTAL WELL COUNT SURVEYED FOR COASTAL OIL & GAS WELLS BY CATEGORY

Population		Prior to 1990		Including 1990 and After		Total Well Count	Actual Wells Surveyed
		Fresh	Saline	Fresh	Saline		
Alaska	Major	640	282	21	39	982	100
Gulf	Major	496	119	174	67	856	133
	Sm. Ind.	95	26	21	2	144	143
	Other	902	355	300	84	1,641	227
ALL		2,133	782	516	192	3,623	603

and all wells owned by small independent operators (143 wells). The remaining 3,177 wells were surveyed using a stratified probability design (see Glossary), which established a representative well population size to be 603 wells. Operators were instructed to provide technical information only on the wells identified and the separation and treatment facility associated with each well.

For Section 3.2 of the Questionnaire, entitled "Drilling Operations," EPA identified 191 wells that had been newly drilled or worked-over during the period of 1990 through 1992. Information on drilling operations was requested for only those identified wells. Of these, 167 were in the Gulf of Mexico and 24 were in Alaska. Data were received for 138 of the 191 wells surveyed for drilling operations.

Of the 361 EPA Questionnaires that were sent out, 89 were out of scope because they were non-coastal operators or out of business. Of the remaining 272 surveyed operators that were in scope, 236 responded in time (as of April 1994) to be included in the database used in this proposal[6]. It was determined that these 236 respondents sufficiently represented industrial operations.

Upon their return, the EPA Questionnaires were reviewed for completeness and technical content and then were transcribed into a computer readable format using double key-entry procedures. Statistical estimates were prepared in order to extrapolate the results from the sampled wells and facilities to the entire coastal industry.[7]

The individual data and the statistical reports were then used in the determining waste volumes, treatment and disposal methods and costs. The survey results were also used to estimate future industrial activity.

4.0 INVESTIGATION OF SOLIDS CONTROL TECHNOLOGIES FOR DRILLING FLUIDS

In 1993, EPA collected samples and gathered technical data at three drilling operations in the coastal region of Louisiana. The purpose of this effort was to gather operating and cost information regarding closed-loop solids control technology at active oil and gas well drilling operations and to collect samples of water generated from drilling waste dewatering operations. Samples were analyzed for a variety of analytes in the categories of organic chemicals, metals, conventional and non-conventional pollutants, radionuclides, and toxicity.

Three drilling operations were visited and samples were collected during drilling of three exploratory wells. The three wells were:

- The Gap Energy well (Sweetlake Land & Oil No.1) in Holmwood, spudded on May 24, 1993;[8]
- The Arco well (Miami Corporation No. 1) on the Black Bayou Prospect in Cameron Parish, spudded on June 22, 1993;[9] and
- The Unocal well (LA. FURS. C-16) at Freshwater Bayou in Vermilion Parish, spudded on August 7, 1993.[10]

The Gap and Arco wells were drilled using land-based rigs, while the Unocal well was drilled using a posted-barge. At the time of the sampling visits, all three wells were being drilled using water-base drilling fluids. However, for one well, oil-based fluids were used for the final section of the well. Table V-2 presents summary information obtained regarding drilling of these three wells.

Samples of dewatering centrifuge liquid were collected to determine the characteristics of this process stream. This process stream consisted mostly of the water phase of the drilling fluid. This dewatering effluent was not discharged at any of the sites visited. One solids control contractor suggested that further treatment with activated carbon would be necessary in order to meet applicable discharge criteria.[9]

TABLE V-2

TECHNICAL DATA FOR THE THREE WELL DRILLING OPERATIONS VISITED

Well Name	Total Depth	Depth at Sampling	Drilling Fluid Type	Solids Control Technologies	Reported Solids Control Efficiency*
Gap Energy Holmwood, LA	12,860 ft.	11,990 ft.	Water-base	Shale Shakers, Degasser, Desander, Desilter with Shaker, Barite Recovery Centrifuge, Chemically Enhanced Centrifugation	90%
Arco Black Bayou Prospect, LA	14,928 ft.	12,741 ft.	Water-base	Shale Shakers, Degasser, Desander, Desilter with Shaker, Barite Recovery Centrifuge, Chemically Enhanced Centrifugation	90%
Unocal Freshwater Bayou, LA	19,260 ft.	12,349 ft.	0-13,545 ft: Water-base >13,545 ft: Oil-base	Shale Shakers, Degasser, Desanders, Desilter with Shaker, Barite Recovery Centrifuge, Centrifuge (no chemical addition)	75%

*Estimate provided by solids control contractor for equipment configuration during day of sampling.

One set of grab samples was collected on two consecutive days from the liquid discharge from the centrifuge processing the drilling fluids. The major difference between the solids control systems was that both Gap and Arco were using chemical treatment of the centrifuge influent with coagulant and polymer to enhance centrifugation during the time of sampling while Unocal was not. The result was that separation of the drilling fluid solids from the water was much more efficient at both the Gap and Arco sites. Both the Gap and Arco samples were relatively free of suspended solids (TSS ranged from 24 to 520 mg/l) while the Unocal samples were analyzed as a solids sample with total solids ranging from 23% to 24.7% and had the consistency of a drilling fluid.

The combination chemical treatment and centrifugation, referred to as "chemically enhanced centrifugation", allows the water to be recycled back into the drilling fluid recirculation system without the build up of fine drill cuttings that is detrimental to the drilling fluid. This drilling technology is discussed in greater detail in Section VII.

In addition to the sampling activities, technical and cost information was collected on the following topics:

- drilling waste volumes and disposal methods
- solids control equipment design and performance
- drilling fluids
- well design and construction
- drilling operations
- annular injection
- miscellaneous waste volumes and disposal methods.

The results of this investigation were used to determine methods and costs of drilling waste disposal, and to provide information on miscellaneous waste volume, treatment and disposal.

5.0 SAMPLING VISITS TO 10 GULF OF MEXICO COASTAL PRODUCTION FACILITIES

From May 11 through November 13, 1992, EPA visited ten coastal oil and gas production facilities located in Texas and Louisiana. The purpose of this effort was to gather operating and cost information at active oil and gas production facilities and to collect samples of produced water and associated wastes. Samples were analyzed for a variety of analytes in the categories of organic chemicals,

metals, conventional and non-conventional pollutants, and radionuclides. Sampling at each site was conducted for one day over a span of eight hours. Technical and cost data were collected in addition to the production waste samples. Table V-3 presents the operator name, field name, and location of the 10 facilities. A report was prepared, entitled "Coastal Oil and Gas Production Sampling Summary Report," that summarizes and describes the samples collected, treatment systems employed, and data generated.[21]

Below is a brief summary of the facilities, the samples collected and the types of pollutants analyzed in this study.[21]

- Of the ten facilities sampled, six were in southeastern Louisiana and four were in southeastern Texas.
- Five were accessible by car and five were accessible by boat.
- One site operator was a small independent company, one was a medium size company, and eight were major companies.
- Four facilities produced only oil and six produced both oil and gas.
- Produced water flowrates ranged from 2,500 bpd to 11,500 bpd.
- Nine facilities utilized injection wells for produced water disposal and one utilized surface discharge.
- Nine facilities utilized settling tanks as the primary step for removal of solids and trace quantities of oil from produced waters.
- One facility utilized a coalescer for removal of trace quantities of oil prior to settling.
- All of the four facilities that were accessible only by boat disposed of produced water using injection wells and utilized filtration as a final treatment step between settling and injection. Three of these facilities used cartridge filters and one used a 200 mesh screen.
- Aqueous samples were collected from settling tank effluent at all ten facilities.
- Aqueous samples were collected at the influent (settling effluent) and effluent of all four filtration systems.
- Aqueous samples were also collected at the influent and effluent of the coalescer, although the effluent samples were analyzed only for oil and grease and TSS.
- Two consecutive four-hour grab composite samples were collected at all aqueous sample locations. Each four-hour aqueous composite was analyzed for the following analytes:
    - Volatile Organics
    - Semi-volatile Organics

TABLE V-3
PRODUCTION FACILITIES SAMPLED

Operator Name	Field Name	Location	Reference
Greenhill Petroleum	Bully Camp	La Fourche Parish, LA	11
Oryx Energy	Chacahoula	La Fourche Parish, LA	12
Exxon Corporation	Clam Lake	Jefferson County, TX	13
Oryx Energy	Caplen	Galveston County, TX	14
Texaco	Sour Lake	Hardin County, TX	15
Texaco	Port Neches	Orange County, TX	16
Arco	Bayou Sale	St. Mary Parish, LA	17
Texaco	Bayou Sale	St. Mary Parish, LA	18
Badger Oil Corporation	Larose	La Fourche Parish, LA	19
Texaco	Lake Salvador	St. Charles Parish, LA	20

- Metals
- Conventional Parameters
- Non-conventional Parameters
- Radionuclides.

- Four consecutive two-hour grab composite samples were also collected at all aqueous sample locations. Each two hour composite was analyzed for the following:

  - Oil and Grease
  - TSS.

- Samples of cartridge filters were collected at all three facilities that utilized them. The samples were analyzed for radionuclides only.

- A grab sample of settling tank bottoms was collected at four facilities. Due to limited quantities available at two of these facilities, one of these samples was analyzed for radionuclides only and the other sample was analyzed for radionuclides and metals only.

- A grab sample of material that was cleaned out of a heater-treater (mostly sand and some oil) was collected at one facility.

- The remaining two settling tank bottoms samples and the heater-treater sample were analyzed for the following analytes:

  - Volatile Organics
  - Semi-volatile Organics
  - Metals

- Conventional Parameter
- Non-conventional Parameters
- Radionuclides.

- One grab sample of coalescer tank bottoms was collected, and since the solids were dilute, the sample was analyzed as a liquid (aqueous) sample.

- One sample of sand generated during the workover of an oil producing well was collected and analyzed for radionuclides only.

Figure V-1 presents the location of the waste samples collected and also presents the five different treatment and disposal sequences observed at the 10 facilities.

In addition to the sampling activities, technical and cost information was collected on the following topics:

- separator and treatment system technologies and configuration
- equipment space requirements
- support structures
- miscellaneous waste volumes treatment and disposal methods
- produced water volumes and disposal methods
- energy requirements
- injection well remedial work requirements
- ancillary equipment requirements (besides the injection well) for injection
- injection well design and operation
- production data.

The results from this study, together with data from the EPA Questionnaire, formed the basis for EPA's produced water treatment and disposal cost analyses discussed later in Section XI. The analytical data was used to characterize produced water effluent characteristics from BPT treatment system.

6.0 STATE DISCHARGE MONITORING REPORTS

EPA was able to obtain detailed information on produced water discharges, for operators in Texas and Louisiana, by reviewing state discharge permits. The Louisiana Department of Environmental Quality (LADEQ) and the Texas Railroad Commission (TRC) supplied state permit data for all known dischargers in the coastal areas.[22] The state permit information identifies the operator, the name of the

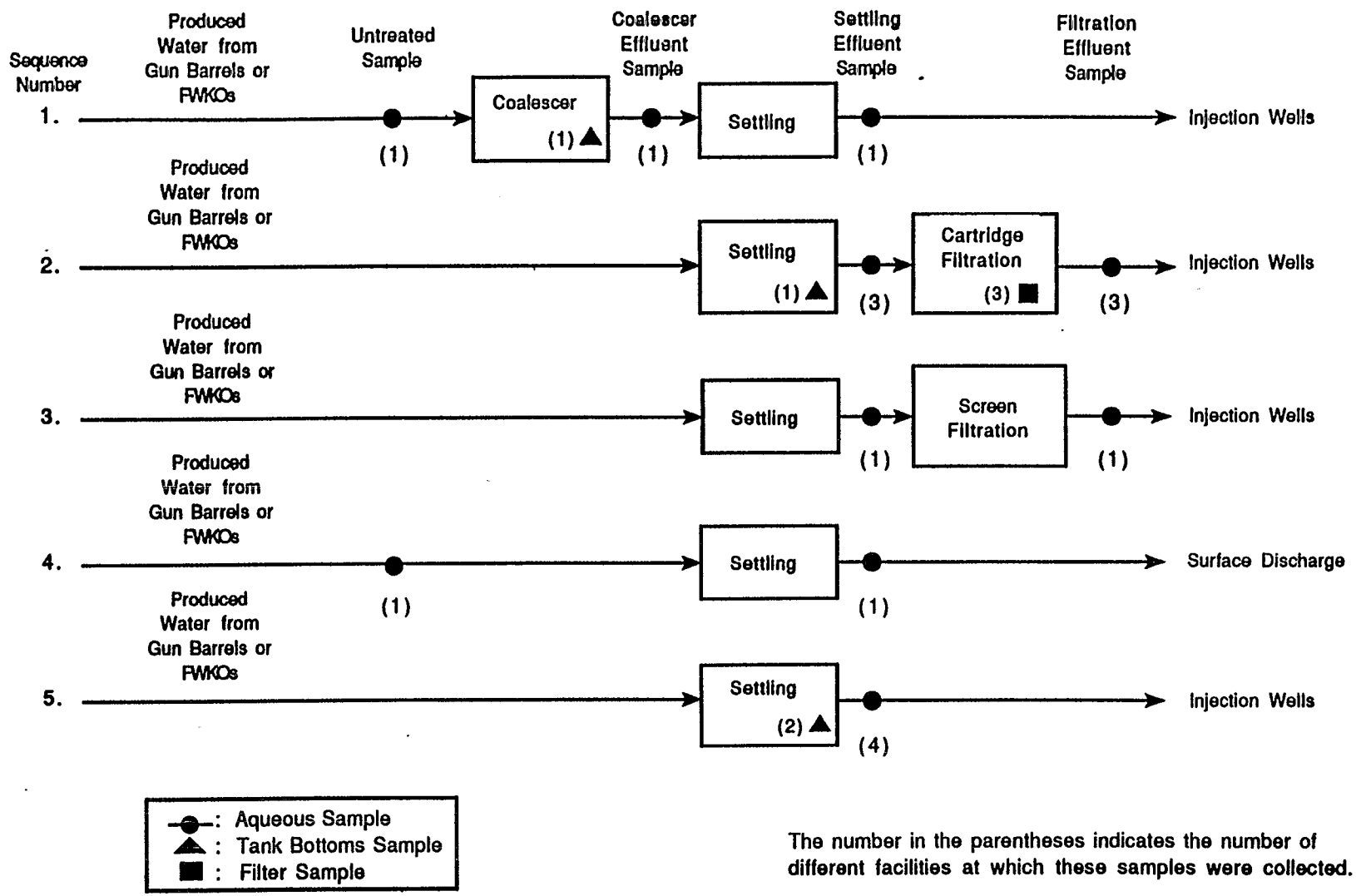

Figure V-1
Sample Locations and Treatment System Sequences at the 10 Coastal Production Facilities

producing field, the location of the production facility, the volume of produced water discharged, the location and permit number of the outfall, and in Louisiana only, the compliance date by which the discharge must cease. From these data, EPA estimated that 216 production facilities in both the Texas and Louisiana coastal region will be discharging after July 1996 (the date of issuance of this regulation). The list of these facilities is presented in Appendix XI-3. A separate document provides a description of the methodology used to complete this list.[22]

7.0 COMMERCIAL DISPOSAL OPERATIONS

7.1 COMMERCIAL DRILLING WASTE DISPOSAL SITE VISIT

In May 1992, EPA visited two non hazardous oil and gas waste land treatment facilities at Bourg and Bateman Island, Louisiana and also two waste transfer stations at Port Fourchon and Morgan City on Bayou Boeuf, Louisiana. Campbell Wells is the operator of these four facilities. The purpose of these visits was to investigate the transportation, handling, disposal methods employed and associated costs of these operations. Detailed information was gathered concerning the operation of the landfarm treatment process used for the disposal of non-hazardous oil field wastes, transportation equipment, transfer equipment, equipment fuel requirements and costs incurred by the facilities and costs charged to the customers. This information was summarized in the "Trip Report to Campbell Wells Landfarms and Transfer Stations in Louisiana."[23] The information was used in the development of compliance costs and the non-water quality impacts for the various regulatory options being considered.

7.2 SAMPLING VISITS TO TWO COMMERCIAL PRODUCED WATER INJECTION FACILITIES

On March 12, 1992, the EPA visited two commercial produced water injection facilities to collect samples and technical data.[24,25] The purpose of the visits was to collect information regarding costs of produced water disposal and other operating costs as well as to collect samples of produced water, filter solids, used filters and tank bottoms solids for radioactivity analysis. The two facilities were Campbell Wells in Bourg, Louisiana and Houma Saltwater in Houma, Louisiana. Both facilities received produced water mostly by truck but also had the capability to receive produced water by barge. Both facilities utilized sedimentation and filtration as treatment processes for produced water followed by to underground injection. The filtration systems differed slightly in that Houma Saltwater used bag and cartridge filters in series while Campbell Wells (Bourg) used only bag filters. At the Campbell Wells (Bourg) facility, water from the landfarming operation was combined with produced water received from offsite prior to treatment and injection.

At both facilities, samples of produced water from the influent and effluent of the filtration system were collected as well as solids from the bag filters, settling tank bottoms and at Houma Saltwater, a used cartridge filter. These samples were then analyzed for Ra-226, Ra-228, Gross Alpha, and Gross Beta. The technical information gathered at these sites was used in developing compliance costs and the non-water quality impacts for the various regulatory options being considered. The results of the radioactivity analyses were used in an evaluation of radioactivity concentrations in oil and gas wastes. This evaluation is described below.

8.0 NORM STUDY

EPA reviewed all known data regarding the presence of naturally occurring radioactive materials (NORM) found in discharges of produced water and associated with scales and sludges (produced sand) generated by production equipment from this industry. The oil and gas production process can extract naturally occurring radionuclides from within the geologic formation. The most common of these radionuclides found are radium-226, radium-228, and lead-210, which are soluble in the produced water. Radium-226 and radium-228 concentrations in ocean water may range from 0.024 to 0.182 pCi/l and 0.0001 to 0.1 pCi/l, respectively.[26]

An EPA report[27], summarizes produced water radioactivity data from the 22 available studies EPA has reviewed, focusing on data from coastal sites. Each of these 22 studies is summarized in that report according to the location of the sites, sampling plans, and analytical methods used to measure the radionuclides.

Tables V-4, V-5 and V-6 summarize the findings from this evaluation. This information was used in characterizing produced water effluents in the Gulf Coast.

9.0 ALASKA OPERATIONS

9.1 REGION X DISCHARGE MONITORING STUDY

In an effort to characterize discharges to Cook Inlet, EPA Region X conducted a comprehensive Discharge Monitoring Study of facilities that discharge produced water.[2] Produced water discharges from production facilities were sampled and analyzed for one year, from September 1988 through August 1989. Samples were collected and analyzed from two oil platforms, one natural gas platform and three shore-based treatment facilities, all of which discharge produced water to Cook Inlet. The results of this sampling effort are summarized in Table XII-15 in the Offshore Development Document[1] and are used

TABLE V-4
SUMMARY STATISTICS OF RADIUM-226 (pCi/l) FROM COASTAL OIL AND GAS SITES[27]

Study	Source	No. of Sites	No. of Samples	Mean	Std	Min	Max
1	Formation Water	15	15	326.5	.	<0.1[a]	1580
2	Untreated Effluent	4	4	195.8	140.6	22	327
	Acidified/Filtered Effluent	6	6	238.8	140.8	16	393
	Acidified/Unfiltered Effluent	7	7	275.9	110.8	46	397
3	Produced Water (all sample pts)	1	14	20.3	9.5	10.6	42.4
	Produced Water Effluent	1	4	14.7	3.4	10.6	18.5
6	Produced Water Effluent (all methods)[b]	407	407	162.8	144.7	0.05	930
	Produced Water Effluent (Method 707E only)[b]	352	352	181.7	141.4	0.1	930
7	Produced Water Effluent	3	6	197.1	72.0	86.8	258.3
8	Produced Water Effluent[c]	1	4	539.0	145.3	448	756
9	Produced Water Effluent	6	8	2.7	2.2	1.1	4.2
10	Produced Water Effluent	4	4	497.0	96.1	355	567
11	Produced Water Eff. (MOGA)[b]	267	267	181.6	.	0.05	792
	Produced Water Eff. (DEQ)[b]	405	405	159.2	.	0.05	930
	Produced Water Eff. (CSA)	3	3	197.1	75.8	110.6	251.9
16	Produced Water Effluent	2	2	96.6	65.7	50.1	143
17	Produced Water Effluent (commercial facilities)[b]	2	2	50.3[d]	7.3[d]	33.9	66.2
	Produced Water Effluent (production facilities)[b]	10	20	172.19[d]	55.1[d]	4.5	420
20	Production Equipment Scale[a]	.	.	360.0[f]	.	.	.
	Production Equipment Sludge[a]	.	.	56.0[f]	.	.	.
	Disposal Wastes[a]	.	.	90.0[f]	.	.	.
21	Produced Water Effluent	25	25	.	.	.	.
22	Drilling Waste Effluent[b]	2	4	2.6[d]	1.2[d]	1.3	5.1
Total	**Produced Water Effluent**	**1128**	**1149**	**168.4[g]**	.	**0.05**	**930**

[a] Detection limit is 0.1 dpm/l.
[b] Samples below the minimum level of detection are set equal to the detection limit.
[c] Four samples analyzed by four different analytical methods.
[d] From SAIC, January 31, 1995[7]
[e] Combination of coastal, offshore, and onshore sites.
[f] Units are pCi/g for these samples.
[g] Mean is weighted average of means from each study of produced water effluent.

TABLE V-5
SUMMARY STATISTICS OF RADIUM-228 (pCi/l) FROM COASTAL OIL AND GAS SITES[27]

Study	Source	No. of Sites	No. of Samples	Mean	Std	Min	Max
1	Formation Water	15	15	.	.	18.7	1248
3	Produced Water (all sample pts)	1	14	24.0	11.6	11.2	54.5
	Produced Water Effluent	1	4	17.5	5.8	11.2	24.9
6	Produced Water Effluent[a]	407	407	184.5	375.9	0[b]	7090
7	Produced Water Effluent	3	6	294.1	69.4	233.6	386
8	Produced Water Effluent	1	1	460.0	.	.	.
9	Produced Water Effluent	6	8	7.5	3.1	5.3	9.7
11	Produced Water Eff. (MOGA)[a]	267	267	219.7	.	0[b]	928
	Produced Water Eff. (DEQ)[a]	405	405	164.5	.	0[b]	928
	Produced Water Eff. (CSA)	3	3	294.1	77.2	244.4	383.0
16	Produced Water Effluent	2	2	98.6	71.3	48.2	149
17	Produced Water Effluent (commercial facilities)[a]	2	2	34.9[c]	4.0[c]	17.5	49.0
	Produced Water Effluent (production facilities)[a]	10	20	228.4[g]	49.4	3.1	500
20	Production Equipment Scale[d]	.	.	120.0[a]	.	.	.
	Production Equipment Sludge[d]	.	.	19.0[a]	.	.	.
	Disposal Wastes[d]	.	.	30.0[a]	.	.	.
22	Drilling Waste Effluent[a]	2	4	7.3[c]	2.4[c]	5.7	10.5
Total	**Produced Water Effluent**	**1107**	**1125**	**168.4[g]**	**.**	**0**	**7090**

[a] Samples below the minimum level of detection are set equal to the detection limit.
[b] One sample was reported with a detection limit of 0 pCi/l.
[c] Mean is arithmetic average of facility means; Standard deviation is pooled within-facility estimate.
[d] Combination of coastal, offshore, and onshore sites.
[e] Units are Pci/g for these samples.
[f] Mean is weighted average of means from each study of produced water effluent.
[g] From SAIC, January 31, 1995[7]

TABLE V-6
SUMMARY STATISTICS OF LEAD-210 (pCi/l)
FROM COASTAL OIL AND GAS SITES

Study	Source	No. of Sites	No. of Samples	Mean	Std	Min	Max
3	Produced Water (all sample pts)[a]	1	14	7.1	0.5	6.4	8.0
	Produced Water Effluent[a]	1	4	7.1	0.4	6.5	7.5
17	Produced Water Effluent (commercial facilities)[a]	2	2	47.4	0.9	42.5	50.5
	Produced Water Effluent (production facilities)[a]	10	20	75.2[b]	27.4[b]	40.1	221.0
20	Production Equipment Scale[c]	.	.	360.0[d]	.	.	.
	Production Equipment Sludge[c]	.	.	56.0[d]	.	.	.
	Disposal Wastes[c]	.	.	90.0[d]	.	.	.
22	Centrifuge Effluent[a]	2	4	12.1[d]	5.6	7.0	19.0
Total	**Produced Water Effluent**	**1128**	**1149**	**168.4[g]**	**.**	**0.05**	**930**

[a] Samples below the minimum level of detection are set equal to the detection limit.
[b] Mean is arithmetic average of facility means; Standard deviation is pooled within-facility estimate.
[c] Combination of coastal, offshore, and onshore sites.
[d] Units are pCi/g for these samples.

in the coastal rulemaking to characterize Cook Inlet BPT produced water discharges.

9.2 EPA Site Visits and Information Gathering Efforts

In 1993, EPA embarked on a fact-finding mission regarding drilling and production operations and practices in both regions of Alaska, Cook Inlet and the North Slope. Information and data were obtained by direct visits to these areas, and by contacting the Alaska Oil and Gas Association (AOGA), state regulatory authorities, and individual operators. The EPA findings from the site visits are presented in a report on Cook Inlet and North Slope oil and gas facilities.[28]

AOGA and individual operators submitted, upon request from EPA, information on projects and technologies currently being developed and used in Cook Inlet and on the North Slope to handle drilling and production wastes, and the costs associated with these projects. The information regarding waste handling methods and technologies was incorporated into a report prepared for EPA.[29] This report, in addition to the climate conditions and current state and Region X regulatory requirements, reviews all

past and current exploration and production waste handling methods in both Cook Inlet and on the North Slope.

The following sections summarize the information EPA has obtained through these efforts.

9.2.1 Drilling Operations on the North Slope

In their effort to achieve zero discharge, operators of oil and gas exploration facilities on the North Slope have developed a grinding and injection system for drilling fluids and cuttings as an alternative to land disposal. The grinding and injection system is a result of many years of investigation of technologies that can achieve zero discharge of drilling wastes.

As part of this program, operators investigated methods to reduce the volume of drilling fluids and cuttings that would require disposal. One such waste reduction method involved the separation of the surface cuttings from the drilling fluid, washing of the cuttings, and determining their potential reuse as construction material. Surface cuttings (cuttings generated from the first 3500 feet of drilled depth) account for approximately 50% of the total cuttings volume. On the North Slope, these cuttings are very similar to sand and gravel from the local pit mines which are used as construction material.[29]

The drill cuttings reclamation program established the potential of surface cuttings reclamation and reuse as construction gravel material. The next step in this program was to establish the technical achievability and costs of winterized, mobile cuttings processing units. In general, the study of the cuttings processing units consisted of processing surface hole cuttings through two separate, mobile, and winterized units. Processed sands and gravel were collected and analyzed at specific intervals to determine their reuse potential as construction materials. Coarse materials were recovered for reuse, while fines and fluids were disposed by means of annular injection below the permafrost.

As a result of this program, successful implementation of the use of grinding and injection for drilling fluids and cuttings disposal on the North Slope has been occurring for the past several years. Wastes are injected beneath the permafrost either through the annulus of an existing well or through a Class II disposal well.[28]

9.2.2 Production Operations on the North Slope

All production waste handling methods on the North Slope are currently regulated by state agencies. Produced water, workover/treatment/completion (WTC) fluids, deck drainage, and produced sand are not discharged from the North Slope coastal facilities including Endicott Island. Only domestic and sanitary wastes may be.discharged on the North Slope, after treatment. Produced water is injected for waterflooding and for disposal into Class II injection wells.[28]

9.2.3 Drilling Operations in Cook Inlet

Marathon Oil Co. and Unocal Corp. recently submitted to EPA a report on drilling waste disposal alternatives and their implementation costs based on projected drilling schedules.[30] Three alternatives were investigated in terms of technological achievability and costs: discharge to Cook Inlet, land-based disposal, and disposal by injection.

EPA evaluated the information presented in this report and utilized the relevant information in the development of regulatory options for drilling wastes in Cook Inlet. Costing information was used to estimate the regulatory compliance costs.

9.2.4 Production Operations in Cook Inlet

Marathon Oil Co. and Unocal Corp. recently submitted to EPA a report on the technological and economic feasibility of zero discharge of produced water from the Trading Bay onshore treatment facility.[31] This report presented the costs and technological achievability for three produced water injection alternatives.

EPA evaluated the information presented in this report and utilized the relevant information in the development of the zero discharge option for produced water in Cook Inlet by injection. Costing information was used to estimate the regulatory compliance costs.

10.0 REGION X DRILLING FLUID TOXICITY DATA STUDY

In order to determine the appropriate toxicity level for a more stringent toxicity option for drilling fluids and cuttings, EPA attempted to evaluate effluent toxicity test results for Cook Inlet drilling fluids and cutting discharges.[32] EPA reviewed permit compliance monitoring records, from EPA's Region 10, containing 161 sets of results for toxicity testing of drilling fluids and drill cuttings used in the Alaska

offshore and coastal regions between 1985 and 1994. (The measure of toxicity is a 96 hour test that estimates the concentration of drilling fluids suspended particulate phase (SPP) that is lethal to 50 percent of the test organisms.) The records were summarized into a database which was evaluated on the basis of the toxicity of drilling fluids and drill cuttings used in Alaska as a whole and Cook Inlet in particular. After sorting the database to eliminate inadequate data, such as drilling fluids contaminated by pills and incomplete toxicity tests, 104 sets of results were retained for all of Alaska, with 59 of these from Cook Inlet.

Of the Cook Inlet bioassay test results, 83 percent were less toxic than 100,000 ppm (SPP); 60 percent were less toxic than 500,000 ppm; and one percent exhibited no toxic effect (i.e., 1 million ppm or greater with less than 50 percent mortality of the test organism). (Note that toxicity is inversely related to the 96-hour bioassay results so as the values cited above increase, toxicity decreases).

These evaluations utilized an available database obtained from EPA's Region 10, which provides an account of the relationship between toxicity and drilling fluids currently being discharged. The toxicity values are identified in the available database by operator, permit number, well name, date and base fluids system (mud). In addition, some of the values are related to an identified volume of muds discharged. However, many of the values in the summary do not have either a volume identified or whether the drilling fluids were discharged. This available database is presently being updated as EPA continues to identify the volume of drilling wastes having been discharged in Cook Inlet related to specific toxicity test results.

11.0 CALIFORNIA OPERATIONS

EPA visited coastal oil and gas operations in Long Beach Harbor, California in February of 1992.[33] Four man-made islands have been constructed in the Harbor for the purpose of oil and gas extraction, and the facilities on these islands are operated by THUMS. EPA met with state regulatory officials and was given a tour of one of the islands by THUMS personnel. Both drilling and production were occurring at the time of the visit.

Information regarding waste generation, treatment, disposal, and costs were obtained during the visit. The information provided EPA with specific waste disposal technology and cost information which has, where appropriate, been incorporated into cost analyses, and enabled EPA to characterize California coastal oil and gas operations.

12.0 OSW SAMPLING PROGRAM

EPA's Office of Solid Waste conducted a sampling program of various oil and gas wastes in 1992.[34,35] As part of this effort, samples were obtained for completion, workover, and treatment fluids. EPA has used this database to characterize the effluent for these fluids. Treatment, workover and completion fluids were collected from operations in Texas, New Mexico, and Oklahoma. The samples were analyzed for conventional, nonconventional and priority pollutants.

13.0 ESTIMATION OF INNER BOUNDARY OF THE TERRITORIAL SEAS

EPA specifically estimated the location of the outer boundary of the coastal subcategory (which is the inner boundary of the Territorial Seas)[36] by estimating the latitude and longitude coordinates covering that part of the inner boundary of the Territorial Seas along Alaska's North Slope and Cook Inlet, Texas, Louisiana, Alabama, and Southern California.

Much of this boundary has been delineated on nautical charts published by the National Ocean Service of the National Oceanic and Atmospheric Administration (NOAA). In some locations, however, this boundary has not previously been delineated by NOAA, and EPA completed the coordinates using established procedures described in the Convention of the Territorial Seas and the Contiguous Zone, Articles 3-13. This boundary was used by EPA to determine the number of coastal oil and gas wells that exist in this subcategory.

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SECTION VI

SELECTION OF POLLUTANT PARAMETERS

1.0 INTRODUCTION

This section presents information concerning the selection of the pollutants to be limited for the proposed Coastal Oil and Gas Extraction Effluent Limitations Guidelines and Standards. The discussion is presented by wastestream.

2.0 DRILLING FLUIDS AND DRILL CUTTINGS

In the coastal subcategory, EPA is proposing to establish BAT, NSPS, and pretreatment standards that would require zero discharge of drilling fluids and drill cuttings. Where zero discharge is required, EPA would be controlling all pollutants in the wastestream.

EPA is also co-proposing as alternative BAT limits applicable only to Cook Inlet, that in addition to the BPT requirement prohibiting the discharge of free oil and diesel oil, and limiting the cadmium and mercury content in stock barite, and limiting toxicity to 30,000 ppm (SPP), another option would enforce these same requirements except with a more stringent toxicity limit of between 100,000 and 1 million ppm (SPP).

EPA is proposing to establish BCT limitations for drill fluids and drill cuttings that would prohibit discharge of free oil (using the static sheen test) for Cook Inlet, and would require zero discharge everywhere else.

The toxic metals identified in drilling fluids and cuttings include zinc, beryllium, cadmium, chromium, copper, nickel, lead, mercury, silver, arsenic, selenium, and antimony. Toxic organic compounds in drilling fluids and cuttings include naphthalene, fluorene, and phenanthrene. Also included are the alkylated forms of the toxic organics along with total oil, TSS and other metals including iron, tin, and titanium. The pollutant data is summarized in Section VII of this document. A zero discharge requirement would control all of these pollutants.

EPA's alternative BAT options would allow discharges of drilling fluids and drill cuttings in Cook Inlet, with certain limitations, including either a prohibition on discharge of free oil, or in addition to the free oil prohibition, prohibit the discharge diesel oil, and require limitations on toxicity and levels of cadmium and mercury in stock barite. For either of these options, EPA would determine that it is not technically feasible to regulate separately each toxic or nonconventional pollutant found in drilling fluids and drill cuttings discharges. If EPA selected one of these alternative options, EPA would determine that control of diesel oil and free oil would control toxic and nonconventional pollutants found in these discharges; and thus, diesel oil and free oil would serve as indicator pollutants for these toxic and nonconventional pollutants, including those that are not otherwise controlled by the diesel and free oil prohibitions. Finally, EPA would determine that controlling toxicity would indirectly control other toxic pollutant metals.

With respect to EPA's proposed BCT option prohibiting discharge of free oil, free oil would serve as a surrogate pollutant for oil and grease in recognition of the complex nature of the oil present in drilling fluids.

2.1 Diesel Oil

Diesel oil may contain 20 to 60 percent by volume poly aromatic hydrocarbons (PAH's) which constitute most of the 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 the discharge of diesel oil would eliminate the discharge of the constituents of diesel oil listed in Table VI-1.

The use of mineral oil instead of diesel oil as an additive in water-based drilling fluids would 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 (See Table VI-1). Mineral oils contain lower concentrations of some of the same pollutants than diesel oil due to their lower aromatic hydrocarbon content and lower toxicity.

2.2 Free Oil

The basis for a prohibition on discharges of free oil in drilling fluids and cuttings is substitution of water-based fluids for oil-based fluids, use of non-petroleum oil containing additives and minimization

TABLE VI-1

ORGANIC CONSTITUENTS OF DIESEL AND MINERAL OILS[1]

Concentration 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 (μg/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 naphthalenes (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 (μg/g) (c)	52.9	106.3	6.60	12.8	ND	ND	ND
Alkylated biphenyls (b)	14.96	4.03	6.51	13.46	0.23	5.57	0.02
Total dibenzothiophenes (μg/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 six 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 coastal drilling operations.

ND = Not Detectable
(a) Includes C1 through C6 alkyl homologues
(b) Includes C1 through C5 alkyl homologues
(c) Includes cresol and C2 through C4 alkyl homologues

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, disposal or reuse. Transporting the drilling wastes to shore would be done instead of product substitution when the used drilling fluids are contaminated by crude oil 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 would be used as an indicator pollutant for the control of toxic pollutants. Free oil would also be used as a surrogate for oil and grease in BCT options in recognition of the complex nature of the oils present in drilling fluids including crude oil from the formation being drilled. Both free oil and diesel oil are considered to be indicators and to control specific toxic pollutants present in the complex hydrocarbon mixtures used in drilling fluid systems. These pollutants include benzene, toluene, ethylbenzene, naphthalene, phenanthrene, and phenol. As an illustration of the relationships between oils and drilling fluids, Table VI-2 shows an increase in oil and grease concentrations from water based fluids to water-based fluids with mineral oil additives. This table is from Section VII-4 of the 1993 Offshore Development Document where characteristics of eight generic drilling fluids, representing water-based drilling fluids commonly used in the drilling industry, were presented.[2]

The relationship between oils and toxic organic constituents can be illustrated by noting, as an example, the concentrations of the toxic organic, phenanthrene, in drilling fluids. Table VI-3 shows an increase in organic constituent concentrations from water based fluids to water-based fluids with mineral additives. Note a particular increase in phenanthrene from "not detected" in water-based fluids, to a range of 1,060 to 19,300 μg/kg in water-based fluids with mineral oil additives. Furthermore, Table VI-1 shows a general trend toward increases in organic concentrations from mineral oils to diesel oils. Note, for phenanthrene in particular, a concentration in the range of not detected to 0.04 mg/ml in mineral oil to a range of 0.36 to 1.85 mg/ml in diesel oil.

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

TABLE VI-2

POLLUTANT ANALYSIS OF GENERIC DRILLING FLUIDS[3]

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 VI-3

ORGANIC POLLUTANTS DETECTED IN GENERIC DRILLING FLUIDS[3]

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 $\mu g/kg$

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 (for more details on the acute toxicity test see the final Offshore Guidelines 58 FR 12507, March 4, 1993 - Appendix 2 to Subpart A of Part 435). The technology basis for the toxicity limitation is product substitution, i.e., substitution using less toxic drilling fluids, or if the toxicity limitation cannot be met, transporting the drilling fluids and cuttings to shore for disposal.

Additives such as oils and some of the numerous specialty additives, especially biocides, may greatly increase the toxicity of the drilling fluid and drill cuttings (due to the adherence of drilling fluid to the drill 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, may not be an effective means of regulating these additives since they are neither diesel oil nor do they contain constituents with a free oil component. A toxicity limitation requires that operators must also 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 or newer drilling fluid compositions with lower toxicity than the generic fluids, and the use of low-toxicity drilling fluid additives.

By regulating the toxicity of drilling fluids and cuttings, certain toxic and nonconventional pollutants are controlled. It has been demonstrated, during EPA's development of the Offshore limitations (discussed in Section V of the Offshore Development Document)[2], that toxicity directly controls the type and amount of mineral oil that can be added to a drilling fluid and pollutants such as PAH's identified as constituents of mineral oil. Drilling fluids and drilling fluid additives with low toxicity would be encouraged by a toxicity limitation.

2.4 CADMIUM AND MERCURY

By limiting cadmium and mercury content in the stock barite, toxic and nonconventional pollutants in drilling fluids and cuttings can be controlled. EPA has determined that it is not technically feasible to specifically control the toxic pollutants controlled by the mercury and cadmium limits. Limitations on cadmium and mercury content in the stock barite would control toxic and nonconventional pollutants in drilling fluids and cuttings discharges. This limitation would indirectly control the levels

of toxic pollutant metals because cleaner barite that meets the mercury and cadmium limits is also likely to have reduced concentrations of other metals.

Barite is an additive used in drilling operations to increase the weight of the drilling fluid necessary when drilling "deep" formations. Barite is mined from either bedded or veined deposits. Research has shown that bedded deposits are characterized by substantially lower concentration of heavy metal contaminants including mercury and cadmium (See Table VI-4). Thus, use of barite from bedded deposits will result in less toxic drilling fluids.

TABLE VI-4

ANALYSIS OF TRACE METALS IN BARITE SAMPLES[4]

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

Table VI-5 presents metal concentrations in barite. Comparing the concentrations of metals for "dirty" versus "clean" barite clearly indicate that for some metals, the concentrations decrease when using "clean" barite and others stay virtually the same. Limiting cadmium and mercury to 3 mg/l and 1 mg/l respectively in stock barite indirectly controls the levels of toxic pollutant metals by using cleaner barite

TABLE VI-5

METALS CONCENTRATION IN BARITE[5]

Metal	"Dirty" Barite Concentration (mg/kg)	"Clean" Barite Concentration (mg/kg)
Priority		
Cadmium	2.3	1.1
Mercury	0.7	0.1
Antimony	**5.7**	**5.7**
Arsenic	12.0	7.1
Beryllium	**0.7**	**0.7**
Chromium	561.4	240.0
Copper	39.9	18.7
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**
Zinc	**200.5**	**200.5**
Nonconventionals		
Antimony	**5.7**	**5.7**
Barium*	**120,000.0**	**120,000.0**
Iron	**15,344.3**	**15,344.3**
Tin	**14.6**	**14.6**
Titanium	**87.5**	**87.5**

* Source: SAIC, Barium Estimate, June 6, 1994

because of reduced concentrations these metals have in clean barite. However, 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 with the concentrations of arsenic, boron, calcium, sodium, tin, titanium, and zinc.[5]

2.5 POLLUTANTS NOT REGULATED

Where zero discharge would be required, all pollutants would be controlled in drilling fluids and cuttings discharges. Where discharges with limitations would be required, EPA has determined that it is not technically feasible to control specifically each of the toxic constituents of drilling fluids and cuttings that are controlled by the limits on the pollutants proposed for regulation.

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 from EPA's field sampling program and does not believe them to be found through out the industry; 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 Coastal Oil and Gas Effluent Guidelines, EPA's preferred BAT option for produced water is to require zero discharge everywhere except for Cook Inlet, Alaska where oil and grease would be limited to a 29 mg/l monthly average and a 42 mg/l daily maximum. The preferred NSPS and pretreatment standards option is zero discharge everywhere. The preferred BCT option is an oil and grease limitation of 48 mg/l monthly average and 72 mg/l daily maximum as required for BPT. These limitations represent the appropriate levels of control under BAT, BCT and NSPS. EPA is controlling all pollutants contained in produced water where zero discharge is required and for Cook Inlet, oil and grease is being regulated as an indicator pollutant to control the discharge of toxic pollutants. Oil and grease would be limited under NSPS as both a conventional and an indicator pollutant controlling the discharge of toxic pollutants.

3.1 POLLUTANTS REGULATED

Where EPA would require zero discharge, EPA would be regulating all pollutants found in produced water. (See Table VIII-4 for a listing of pollutants found in produced water). Where produced water discharges would be allowed, (in Cook Inlet for BAT, and under BCT) EPA would be regulating oil and grease as an indicator for toxics and nonconventional pollutants and as a conventional pollutant.

As previously denoted in the Offshore Technical Development Document (Section VI), oil and grease serves as an indicator for toxic pollutants in the produced water wastestream which include phenol, naphthalene, ethylbenzene, and toluene. Also see Table VIII-3 of Section VIII which lists 35 organics detected at least once in EPA's sampling programs. The remaining toxic organic pollutants were not detected.

The technology basis for the oil and grease limitations is gas flotation. In addition to oil and grease, 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 of oil and grease for the above priority pollutants. (See Section VIII for discussions of gas flotation technology.)

During the Offshore Guidelines development, EPA determined the characteristic of produced water both after the BPT level of control and after gas flotation technology. This data, shown here in Table VI-6 demonstrates that as oil and grease is removed, so too are the organic pollutants. (Note, this table is taken from the Offshore Guidelines and presents data that may be different from that used in the development of the Coastal Guidelines presented throughout the proceeding sections of this document).

3.2 POLLUTANTS NOT REGULATED

Where EPA would require zero discharge, all pollutants found in produced water would be regulated. Thus, this discussion pertains only to EPA's BAT option for Cook Inlet and EPA's BCT option.

The feasibility of regulating separately each of the constituents of produced water determined to be present was also evaluated during the development of the Offshore Guidelines (See Section VI of the Offshore Technical Development Document).[2] EPA determined that it is not feasible to regulate each pollutant individually for reasons that include the following: 1) the variable nature of the number of constituents in the produced water, 2) the impracticality of measuring a large number of analytes, many of them at or just above trace levels, 3) use of technologies for removal of oil which are effective in removing many of the specific pollutants, and 4) many of the organic pollutants are directly associated with oil and grease because they are constituents of oil, and thus, are directly controlled by the oil and grease limitation. These reasons apply to the Coastal Guidelines.

TABLE VI-6

POLLUTANT LOADING CHARACTERIZATION - PRODUCED WATER[3]

Pollutant Parameter	BPT-Level Effluent	Improved Gas Flotation Effluent
	Concentrations mg/l	
Oil & Grease	25.0	23.5
TSS	67.5	30.0[a]
	Concentrations μg/l	
Priority and Non-conventional Organic Pollutants:		
2-Butanone	1028.96	411.58
2,4-Dimethylphenol	317.13	250.00
Anthracene	18.51	7.40
Benzene	2978.69	1225.91
Benzo(a)pyrene	11.61	4.65
Chlorobenzene	19.47	7.79
Di-n-butylphthalate	16.08	6.43
Ethylbenzene	323.62	62.18
n-Alkanes	1641.50	656.60
Naphthalene	243.58	92.02
p-Chloro-m-cresol	25.24	10.10
Phenol	1538.28	536.00
Steranes	77.50	31.00
Toluene	1897.11	827.80
Triterpanes	78.00	31.20
Total xylenes	695.03	378.01
Priority and Non-conventional Metal Pollutants:		
Aluminum	78.01	49.93
Arsenic	114.19	73.08
Barium	55563.80	35560.83
Boron	25740.25	16473.76
Cadmium	22.62	14.47
Copper	444.66	284.58
Iron	4915.87	3146.15
Lead	195.09	124.86
Manganese	115.87	74.16
Nickel	1705.46	1091.49
Titanium	7.00	4.48
Zinc	1190.13	133.85

a Source: SAIC, January 13, 1993.[8]

Note: This table is taken from the Offshore Development Document and used here for illustrative purposes. It may not be the same as data presented for the coastal produced waters presented later in Section VIII.

While the oil and grease limitations limit the discharge of toxic pollutants, EPA determined during the Offshore Guidelines rulemaking, that certain of the toxic priority pollutants, such as pentachlorophenol, 1,1-dichloroethane, and bis(2-chloroethyl) ether would not be controlled by the limitations on oil and grease in produced water. EPA is not proposing to regulate these pollutants in this rule because EPA did not detect them in the samples within the coastal oil and gas data base. (See the Offshore Development Document, Section VI, page VI-7).

Naturally Occurring Radioactive Materials (NORM), mainly consisting of radium 226 and radium 228, in produced water was found in concentrations averaging 400 pCi/l (for both Radium 226 and Radium 228 combined, sometimes referred to as total radium) in the coastal areas of the Gulf of Mexico.[9] This pollutant would be eliminated by a zero discharge requirement.

Existing data for NORM in Cook Inlet shows an average NORM discharge concentration of 4.51 pCi/l (total radium).[10] This is less than the concentrations necessary for compliance in drinking water standards[11] (5 pCi/l for total radium) or Louisiana state regulations[12] (60 pCi/l, soluble radium), and thus, indicates the concentration of NORM discharged into Cook Inlet waters to be low. Therefore, NORM is not being considered as a pollutant necessary for regulation in Cook Inlet.

Produced water treatment technology has not been shown to remove NORM. According to data submitted for the offshore record, removals of radium 226 and radium 228 by granular filtration and improved gas flotation, if any, are believed to be minimal.[7] The Offshore Development Document also presents the membrane filtration performance on pollutant removals (summarized on Table IX-17 of that document), which shows insignificant radium removals.

4.0 WELL TREATMENT, WORKOVER, AND COMPLETION FLUIDS

EPA's is co-proposing two options for BAT & NSPS for controlling pollutants found in well treatment, completion and workover fluids: 1) require limitations prohibiting the discharge of free oil, or 2) to require zero discharge for all coastal areas except for Cook Inlet, where EPA proposes oil and grease limitations of 29 mg/l 30-day average and a 42 mg/l daily maximum, (same limitations being proposed for produced water). EPA is also proposing a no discharge of free oil limitation for BCT as determined by the static sheen test and a zero discharge requirement for all coastal areas under NSPS, PSES and PSNS. These limitations represent the appropriate level of control under BAT, BCT, PSES, PSNS and NSPS.

Where EPA proposes zero discharge, EPA would be controlling all pollutants found in well treatment, workover and completion fluids. As with produced water, oil and grease serves as an indicator for toxic pollutants in well treatment, workover and completion fluids 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 reflect control of these toxic pollutants at the BAT and NSPS levels. EPA would regulate free oil as a surrogate for the control of oil and grease in recognition of the complex nature of oils.

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 and/or free oil in the Coastal 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. These pollutants are the same as those listed in produced waters as not being controlled by an oil and grease limitation. 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 coastal subcategory; and the pollutants when found are present in trace amounts not likely to cause toxic effects.

5.0 PRODUCED SAND

EPA is proposing BPT limitations for produced sand equal to zero discharge, which will serve to control all pollutants present in the produced sand wastestream. This limitation represents the appropriate level of control under BAT, BCT, NSPS, PSES and PSNS.

6.0 DECK DRAINAGE

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 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 section 2, subsection 2.2 of this chapter 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.

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

1. Batelle New England Marine Research Laboratory, "Final Report for Research Program on Organic Chemical Characterization of Diesel and Mineral Oils Used as Drilling Mud Additives" prepared for the Offshore Operators Committee - December 31, 1984 (*Offshore Rulemaking Record, Volume 13*).

2. Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category, EPA 821-R-93-003, January 1993.

3. CENTEC Analytical Services Inc., "Results of Laboratory Analysis and Findings Performed on Drilling Fluids and Cuttings - Draft," submitted to Effluent Guidelines Division, U.S. EPA, April 3, 1984 (*Offshore Rulemaking Record Volume 13*).

4. Kramer, J.R., H.D. Grundy, and L.G. Hammer, "Occurrence and Solubility of Trace Metals in Barite for Ocean Drilling Operations," Symposium - Research on Environmental Fate and Effects of Drilling Fluids and Cuttings, Sponsored by API, Lake Buena Vista, Florida, January 1980. (*Offshore Rulemaking Record 26*).

5. 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*).

6. SAIC, Worksheet entitled "Calculation for Average Density of Dry Solids in Cook Inlet Drilling Mud," June 6, 1994.

7. Memorandum from Ronald Jordan, Engineering and Analysis Division, U.S. EPA, to Record. "Offshore Oil and Gas - Characterization of BPT- and BAT- Level Produced Water Effluent," December 10, 1992.

8. SAIC, "Analysis of Oil and Grease Data Associated with Treatment of Produced Water by Gas Flotation Technology," prepared for the Engineering and Analysis Division, U.S. EPA, January 13, 1993.

9. SAIC, "Statistical Analysis of Effluent from Coastal Oil and Gas Extraction Facilities (Final Report)," September 30, 1994.

10. Alaska Oil and Gas Association (AOGA), "Comments on USEPA 40 CFR Part 435 Oil and Gas Extraction Point Source Category, Offshore Subcategory, Effluent Limitations Guidelines and New Source Performance Standards, Proposed Rule," May 19, 1991. (*Offshore Rulemaking Record Volume 138*).

11. 40 CFR Part 141, Subpart B (Drinking Water Standards).

12. Louisiana Code (LAC) Title 33, Part IX. Water Quality Regulations Chapter 7, March 20, 1991.

SECTION VII

DRILLING WASTES
CHARACTERIZATION, CONTROL AND TREATMENT TECHNOLOGIES

1.0 INTRODUCTION

The first three parts of this section describe the sources, volumes, and characteristics of drilling wastes generated from coastal oil and gas exploration and development activities. The last part of this section describes the control and treatment technologies currently available to reduce the volume of drilling wastes and the quantities of pollutants discharged to surface waters.

2.0 DRILLING WASTE SOURCES

This section focuses on three wastes generated during drilling: spent drilling fluid, drill cuttings, and dewatering liquid. Drilling fluid and drill cuttings are both major wastes streams of concern because they are generated in significant volumes. Dewatering liquid is a process stream that sometimes becomes a waste stream, but is most often either recycled or sent offsite with waste drilling fluids and cuttings to commercial disposal facilities.

2.1 DRILLING FLUID SOURCES

Drilling fluids, also referred to as drilling muds, are suspensions of solids, chemicals, 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 (called "additives" in this report) to control density (weight) and viscosity, reduce fluid loss to the formation, inhibit corrosion, and control or impart other properties to the drilling fluid.

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 jets in the drill bit. The drilling fluid returns to the surface through the annulus (space between the casing and the drill pipe). As the fluid travels up the annulus, it carries the drill cuttings in suspension. The fluid then passes through the solids control equipment (shale shaker screens, hydrocyclones, etc.) to remove the

cuttings, and is returned to the mud tank for recirculation. The design and use of solids control equipment are discussed in detail in Section 5.5, "Waste Minimization-Enhanced Solids Control."

Excess drilling fluids are removed from the fluid circulation system during the drilling operation and at the end of the drilling program for various reasons. Excess drilling fluids are generated during drilling when:

- cement, casing, drill pipe or packer fluid are placed downhole,
- the fluid is diluted to maintain constant rheological properties, and
- the entire drilling fluid system is periodically changed over in response to changing drilling conditions.

At the end of the drilling program, the remaining fluid left over in the circulation system and the storage tanks is either considered waste or recycled and/or regenerated for future use.

2.2 Drill Cuttings Sources

Drill cuttings are small pieces of formation rock that are generated by the crushing action of the drill bit. Additional hole material can slough off the drill hole wall, which is commonly referred to as "washout." Drill cuttings are carried out of the borehole with the drilling fluids. Drill cuttings can disperse as fine drill solids into the drilling fluids and can significantly effect the fluid's rheological (flow) properties. Solids control is the process of maintaining the concentration of drill solids in the drilling fluid at an acceptable level. The most common solids control methods are mechanical removal, dilution, and displacement.

Dilution and displacement are usually practiced together because each method is dependent on the other. As the level of fine drill solids increases in the drilling fluid, the viscosity also increases. For a drilling fluid to remain effective, the viscosity must be maintained at a specific level. Diluting the drilling fluid with make-up water has been the traditional method of viscosity control. In order to maintain other properties of the drilling fluid after dilution, additives must be mixed into the fluid in correct proportions. Therefore, the dilution method of viscosity control increases the total volume of drilling fluid in the system and requires the purchase of additional drilling fluid materials. Since the drilling fluid circulation system can hold only a limited volume of fluid at any time, the excess volume generated as a result of dilution must be removed from the active system. Thus, the major waste

generated from the use of dilution/displacement is spent drilling fluid. The disposition of the displaced drilling fluid depends on several factors including, but not limited to, site location, applicable regulations, and the operator's waste management budget. Detailed discussions regarding the management and disposal of waste drilling fluid are provided in later sections.

Viscosity can also be maintained by mechanically separating undesirable solids (drill cuttings) from the drilling fluid (see also Section 5.5). It is important to note that dilution/displacement is often practiced in combination with mechanical solids control as a means of maintaining desired drilling fluid properties, although the amount of excess drilling fluid is minimized in this application. The major waste resulting from mechanical solids control is drill cuttings with adhering drilling fluid. The disposition of the waste drill cuttings depends on the same factors listed above for waste drilling fluid. These factors are discussed in detail in later sections.

2.3 DEWATERING LIQUID SOURCES

Dewatering liquid may come from one of two sources: the dewatering of waste drilling fluids and/or cuttings storage vessel or pit, or from a dewatering centrifuge used as part of the solids control system. EPA does not consider this as a separate waste stream because it is often recycled back into the drilling fluid circulation system as make up water or mixed with waste drilling fluids and cuttings that are sent to offsite commercial disposal facilities. EPA investigated this particular potential waste source because it has been regulated separately in the Region VI general NPDES permit (55 FR 23348). Dewatering liquid was the focus of an EPA sampling program at three active drill sites in southern Louisiana.[1,2,3] These sampling efforts are described in Section V.4.0, "Investigation of Solids Control Technologies for Drilling Fluids." These data were not used for regulatory purposes because EPA later determined through contacts with industry and onsite visits, that this waste stream is rarely discharged as a separate waste. The technical aspects of dewatering liquid generation are discussed in greater detail in Sections 5.5.5 and 5.5.6.

3.0 DRILLING WASTE VOLUMES

Approximately 79,000 bbls per year of drilling fluids and cuttings are being discharged by the coastal oil and gas industry, all of which is occurring in Cook Inlet. This is equal to approximately 553,000 barrels of drilling fluids and cuttings from all of the drilling projects currently planned by industry extending until the year 2002. The following sections discuss the factors affecting the volumes of drilling waste generated and numerical estimates of these volumes.

3.1 FACTORS AFFECTING DRILLING WASTE 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 fluid 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:

- 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 EPA Offshore Oil and Gas Development Document describes the affect of each of these factors on drilling fluid volume.[4].

The volume of drill cuttings generated depends primarily on the dimensions (depth and diameter) of the well drilled and on the percent washout. Washout is the enlargement of a drilled hole due to the sloughing of material from the walls of the hole. 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 and washout tends to be higher. Continuous and intermittent discharges are normal occurrences in the operation of solids control equipment. Such discharges occur for periods from less than one 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 can affect the amount of 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 volume of drill solids generated will be at least equal to the borehole volume, but is most often greater due to the breaking up of the compacted formation material.

Additional information regarding hole enlargement due to washout is listed in Table VII-1. These data were provided to EPA by drill site operators during visits to three coastal sites in southern Louisiana.[1,2,3] Because the volume of washout varies depending on the type of formation being drilled, no single set of numbers can be applied as a rule of thumb to all drilling situations. However, Table VII-1 indicates that the percent washout generally decreases with hole depth. It should be noted that the values in Table VII-1 were estimates obtained from industry operators during EPA's drilling site study and were not directly measured.

3.2 Estimates of Drilling Waste Volúmes

In order to compare waste volumes generated during various drilling projects, a normalized waste volume can be determined by dividing the total reported waste discharged from the active drilling fluid circulation system by the total volume of hole drilled. The volume of hole drilled is calculated from the bit sizes used for specific depth intervals, and from estimated washout volumes. The volume of waste discharged is typically available from waste transport reports or other records maintained at the drill site, and are often estimated based on the volume of the vessel used to store and/or transport the waste. Once calculated, the ratio of waste-to-hole volume can then be compared between drilling projects. For drill cuttings, this ratio is called the "expansion factor" because it indicates how much a given volume of cuttings increased after it was drilled out of the hole. No such distinctive name is used for the ratio of waste drilling fluid to calculated hole volume. For both drilling fluids and cuttings, the waste-to-hole volume ratio should always be greater than one, although in some cases it is less than one due to the disposal of fine cuttings with the waste mud, or to inaccurate waste volume tracking procedures or records. Table VII-2 lists the hole volumes, waste volumes, and the calculated waste-to-hole volume ratios for eight different drilling projects in the coastal Gulf of Mexico region. The first three projects were created based on a "model well" as part of EPA Region VI's development of two general NPDES permits for coastal Louisiana and Texas (55 FR 23348), and were not actual wells drilled. The characteristics of the model well (e.g., depth intervals, hole volume, percent washout, etc.) and the solids control system parameters were designed to represent typical coastal drilling projects. The remaining five projects in Table VII-2 were actual wells, including two offshore and three coastal.

TABLE VII-1. PERCENT WASHOUT FACTORS

Reference	Depth Interval (feet)	Percent Washout
SAIC, May 25, 1994[1]	0 - 3,000	100
	3,000 - 11,500	25-50
	> 11,500	10
SAIC, Aug. 8, 1994[2]	0 - 4,000	75
	4,000 - 11,000	40
	11,000 - 13,000	20
	> 13,000	10
SAIC, Aug. 5, 1994[3]	0 - 3,000	100
	3,000 - 10,000	50
	> 10,000	25-50

A number of observations can be made from the data in Table VII-2. Referring to the EPA Region VI data only, it is apparent that as solids control system efficiency increases, the mud-to-hole volume ratio decreases and the cuttings expansion factor increases. A low efficiency solids control system will allow a significant volume of drill cuttings to remain in the circulating drilling fluid, thus requiring greater dilution of the drilling fluid and hence increasing the volume to be disposed. A higher efficiency solids control system will remove a greater volume of cuttings from the circulating drilling fluid, thus decreasing the need for dilution as well as the volume of waste drilling fluid. In addition, if chemically enhanced centrifugation (CEC) is part of the solids control system, the volume of waste solids should be slightly higher than systems not using CEC because the flocculated solids add to the volume discharged by the centrifuge.

These trends are to be expected, but are not always observed in practice due to site-specific conditions, inaccuracies in hole volume estimation, and in waste volume tracking and reporting. Data from the five actual drilling projects listed in Table VII-2 illustrate this point. The cuttings expansion factors for the two offshore drilling projects are both less than one, suggesting that washout volumes may have been overestimated and that a significant volume of cuttings may have been included with the discharged mud volume. Also, the 8,130 barrels of cuttings reported for the last drilling project in

TABLE VII-2 WASTE DRILL CUTTINGS AND DRILLING MUD VOLUMES

Reference	Closed-Loop Solids Control Equipment Efficiency	Well Depth (ft)	Calculated Hole Volume[a] (bbls)	Waste Drilling Fluids Volume[b] (bbls)	Drilling Fluids-to-Hole Ratio (bbls/bbls)	Waste Cuttings Volume[b] (bbls)	Cuttings Expansion Factor[c] (bbls/bbls)
55 FR 23348 (EPA Region VI general NPDES permit)	Scenario 1: 36%	15,000	1,881	21,220	11.2	2,264	1.20
	Scenario 2: 62%			12,938	6.88	3,301	1.75
	Scenario 3: 90%			3,405	1.81	3,889	2.07
Offshore Operators Committee, 1981[5] (Data for two offshore wells)	50%	10,000	2,453	5,349	2.18	1,430	0.58
		18,000	4,619	10,486	2.27	2,781	0.60
SAIC, May 25, 1994[1] (Data obtained during EPA site visit)	90%	12,860	2,126	2,690	1.27	3,256	1.53
SAIC, August 8, 1994[2] (Data obtained during EPA site visit)	90%	14,928	3,689	5,850	1.59	10,070	2.73
SAIC, August 5, 1994[3] (Data obtained during EPA site visit)	75%	19,260	7,510	8,198	1.09	8,130	1.08
Average	70%	15,000	3,173	8,767	3.54	4,390	1.44

[a] "Hole Volume" was calculated from drilled hole diameter and depth data provided in the references. The data have been adjusted to compensate for hole enlargement due to erosion (washout).

[b] "Discharged Cuttings/Mud Volume" includes the total volume of cuttings or spent drilling fluids that were either discharged or hauled-off by the end of drilling, as reported in the references. These values may be derived estimates or actual data, depending on the reference document.

[c] "Expansion Factor" = Discharged Cuttings Volume (bbls) / Calculated Hole Volume (bbls).

this table is known to include 591 barrels of spent drilling fluid and is believed to include more, particularly because the cuttings were collected in a barge and there was no other holding vessel dedicated to spent drilling fluid at the site. Such uncertainties about what is included in a load of drilling waste and its volume occur because there are no requirements for keeping waste drilling fluid and cuttings volumes separate when they are being hauled offsite.

Volumes of waste drilling muds and cuttings generated by operators located in Cook Inlet, Alaska were reported in responses to the 1993 EPA Questionnaire for Coastal Oil and Gas Operators.[6] From the data submitted in the survey and information obtained directly from the operators, an average volume of muds and cuttings generated was calculated to be 14,354 barrels from an average well of 11,765 feet in depth. Table VII-3 lists the data used to calculate these averages.[5]

Based on this estimation and on projected drilling schedules provided by operators in Cook Inlet, the total volume of drilling wastes generated from drilling activities in Cook Inlet is a total of 553,000 bbls over the 7 years following promulgation of this rule, or 79,000 bbls per year (see Section X for details).

3.3 Dewatering Liquid Volumes

Estimates of dewatering liquid volumes were obtained from two of the three drilling operations visited by EPA in 1993.[1,2] Referring to Table VII-2, the wells drilled to depths of 12,860 and 14,928 feet generated estimated volumes of 4,800 and 2,423 barrels of dewatering liquid, respectively. Although a larger hole volume is generally associated with larger volumes of waste fluids and cuttings, there is no apparent relationship between well depth and dewatering liquid volume. As explained in Sections 5.5.5 and 5.5.6, factors affecting the volume and quality of the liquid effluent from a dewatering process are related to the selected dewatering method and the efficiency of the upstream solids separation equipment rather than the well depth.

4.0 DRILLING WASTE CHARACTERISTICS

4.1 Drilling Fluid Characteristic

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 section discusses only water- and oil-based fluids because they represent the traditional and most widely used drilling fluids.

TABLE VII-3
COOK INLET DRILLING WASTE VOLUMES

Operator ID	Depth Interval #1 (feet)	Depth Interval #2 (feet)	Depth Interval #3 (feet)	Total Well Depth (feet)	Muds and Cuttings Volume Int. #1 (bbls)	Muds and Cuttings Volume Int. #2 (bbls)	Muds and Cuttings Volume Int. #3 (bbls)	Total Muds and Cuttings Volume (bbls)
A	1,389	8,477	2,029	11,895	1,528	9,325	2,232	13,085
A	1,256	8,368	2,176	11,800	1,213	8,081	2,101	11,395
A	1,155	8,642	2,343	12,140	1,361	10,180	2,760	14,300
B	2,110	7,999	860	10,969	3,313	7,334	1,334	11,981
B	4,120	5,962	1,478	11,560	Not Available	9,558	1,583	Not Available
B	4,017	5,745	2,068	11,830	6,065	7,606	2,326	15,997
B	3,823	6,240	2,100	12,163	7,504	8,838	3,024	19,366
AVERAGE	**2,553**	**7,348**	**1,865**	**11,765**	**3,497**	**8,703**	**2,194**	**14,354**

Source: EPA, July 1993[6]

Oil-based muds are only used for specific drilling conditions because they cannot be discharged and are more expensive to use than water-based muds. The discharge of oil-based muds and associated cuttings is prohibited under the BPT limitations 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.[7] 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 washout problems when drilling thick, water-sensitive shales. A primary concern when using conventional, oil-based fluid 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 fluid systems have replaced diesel oil-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 fluids contain bentonite (sodium montmorillonite clay) and caustic soda (NaOH), while saltwater fluids 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 drilling fluid properties and the additives used to enhance these properties are discussed below.

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 (flow properties)
- 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 specific well and drilling conditions through the addition of active solids, inactive solids, and chemicals to the base drilling fluid. The EPA Offshore Development Document discusses each of the above-listed properties, and describes the individual components of drilling fluids as well as typical drilling fluid compositions.[4] A comprehensive list of drilling fluid components and their applications is provided in Appendix VII-1.[8]

Barite, which is used to control the density of drilling fluids, is the primary source of toxic metal pollutants. The characteristics of raw barite will determine the concentrations of metals found in the spent drilling fluid system. A statistical analysis of metals concentrations in spent drilling fluids showed a higher concentration of toxic metal pollutants in drilling fluids formulated with "dirty" barite than in those formulated with "clean" barite.[9]

Based on the results of this analysis, EPA developed a profile of metals concentrations in drilling fluids formulated with "clean" barite as part of the development of Offshore Guidelines. "Clean" barite is defined as stock barite that meets the maximum limitations of cadmium of 3 mg/l and for mercury of 1 mg/l.[4] Table VII-4 presents the estimated characteristics of drilling fluids and cuttings taylored specifically for Cook Inlet since drilling wastes are discharged in this area only. Table VII-4 includes the offshore metals concentration profile developed from the statistical analysis for "clean" barite. The only difference to be noted is the concentration of barium, which was reevaluated in this rulemaking effort because the average weight of drilling fluid (10 lb/gal) reported by Cook Inlet operators in the 1993 EPA Coastal Questionnaire was lower than the average offshore model fluid weight of 11.0 lb/gal. The revised barium concentration for coastal regulations was calculated to be 120,000 mg/kg as compared to the calculated concentration of 359,747 mg/kg estimated for the offshore model well.[10]

Mineral oil, which is used in Cook Inlet drilling operations mostly to free stuck pipe, is a drilling fluid additive that contributes toxic organic pollutants to the drilling fluid system. An operator in Cook Inlet, Alaska recently estimated that the amount of mineral oil typically used in water-based drilling fluids is approximately 0.02 percent.[6] The concentrations of organic compounds listed in Table VII-4 were calculated based on this estimate,[11] and on the average concentrations of organics in mineral oil as listed in Table VII-9 in the Offshore Development Document.[4]

TABLE VII-4. COOK INLET DRILLING WASTE CHARACTERISTICS

Waste Characteristics	Value	Reference
Percent of cuttings in waste drilling fluid	19%	1993 EPA Survey of Coastal Oil and Gas Operators[6]
Average density of cuttings	980 pounds per barrel	Estimated[12]
Average density of waste drilling fluid	420 pounds per barrel	1993 EPA Survey of Coastal Oil and Gas Operators[6] and Calculations[15]
Percent of dry solids in waste drilling fluid, by volume	11%	Calculations [10]
Average density of dry solids in waste drilling fluids	1,025 pounds per barrel	Calculations [10]
Drilling Fluid Pollutant Concentration Data		
Conventionals	lbs/bbl of drilling fluid	Reference
Total Oil	0.0596	Estimated[11]
Total Suspended Solids	113.0	Estimated[10]
Priority Metals	mg/kg dry drilling fluid	Reference
Cadmium	1.1	Offshore Development Document, Table XI-6[4]
Mercury	0.1	
Antimony	5.7	
Arsenic	7.1	
Beryilium	0.7	
Chromium	240.0	
Copper	18.7	
Lead	35.1	
Nickel	13.5	
Selenium	1.1	
Silver	0.7	
Thallium	1.2	
Zinc	200.5	
Priority Organics	lbs/bbl of drilling fluid	Reference
Naphthalene	0.0000035	Calculated [11] from concentrations in Offshore Development Document, Table VII-9[4]
Fluorene	0.0000563	
Phenanthrene	0.0000084	
Non-Conventional Metals	mg/kg dry drilling fluid	Reference
Aluminum	9,069.9	Offshore Development Document, Table XI-6[4]; except for barium, which was estimated.[10]
Barium	120,000.0	
Iron	15,344.3	
Tin	14.6	
Titanium	87.5	
Non-Conventional Organics	lbs/bbl of drilling fluid	Reference
Alkylated benzenes (a)	0.0021017	Calculated [11] from concentrations in Offshore Development Document, Table VII-9[4]
Alkylated naphthalenes (b)	0.0000344	
Alkylated fluorenes (b)	0.0001218	
Alkylated phenanthrenes (b)	0.0000143	
Total biphenyls (b)	0.0001360	
Total dibenzothiophenes	0.0000004	

The TSS attributable to drilling fluids is estimated based on two physical properties of the waste drilling fluids: the estimated percentage of the fluid that is dry solids (11%), and the estimated density of the dry solids (1,025 lbs/bbl).[10] The dry solids content of the drilling fluid was estimated from mud reports provided by the operator of one of the drill sites visited by EPA.[1] The density of dry solids was estimated based on the mud weight of 10.1 lbs/gal obtained from the mud reports,[1] and calculated by subtracting the density of water (in lbs/gal) from the mud weight.[10] Finally, the TSS concentration in drilling fluid was calculated as follows:

(0.11 bbl dry solids/bbl drilling fluid) x (1,025 lbs dry solids/bbl dry solids)
= 113 lbs dry solids/bbl drilling fluid

4.2 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 hydrocarbons which adsorb on the surface of drill solid particles and resist removal by washing operations. The volume of the fluid adhering to the discharged cuttings can vary considerably depending on the formation being drilled, the type of drilling fluid being used, the particle size distribution of the cuttings, and the efficiency of the solids control equipment. A general rule of thumb is that five percent (5%) drilling fluid by volume is associated with the cuttings.[16] Data from a drilling project in the Outer Continental Shelf off southern California indicate that the cuttings discharges from the solids control equipment were comprised of 96 percent cuttings and four percent adhered drilling fluids.[17]

For the purpose of estimating pollutant reductions, the total suspended solids (TSS) concentration attributable to drill cuttings is equivalent to the density of the dry weight of cuttings (980 lbs/bbl).[12] This density was estimated from Cook Inlet geologic information provided by the industry,[13] and the specific gravities of low- and high-gravity solids,[14] as follows:

- The first 500 feet of depth consists of high-gravity solids[13] with a specific gravity of 4.5.[14]
- The depth from 500 to 10,000 feet consists of low-gravity solids[13] with a specific gravity of 2.6.[14]
- 50% of the total cuttings volume is generated during the first 3,000 feet.[6]

- The average specific gravity for the first 3,000 feet (50% of the total volume) =
  [(4.5 x 500 ft) + (2.6 x 2,500 ft)] / 3,000 ft = 2.92

- The average specific gravity for the remaining depth = 2.6

- The overall specific gravity for drilling cuttings =
  (2.92 + 2.6) / 2 = 2.8

- The average density of dry cuttings (using water at standard temperature and pressure as a reference) =
  2.8 x 350 lbs water/bbl = 980 lbs/bbl

4.3 DEWATERING LIQUID CHARACTERISTICS

During site visits to three southern Louisiana drilling operations, EPA collected samples of dewatering centrifuge liquid to determine the quality of this process stream.[1,2,3] This process stream consisted mostly of the water phase of the drilling fluid.

At each drill site, one set of grab samples was collected on two consecutive days from the liquid discharge from a decanting centrifuge that was part of the solids control system (see also Section 5.5.5). The major difference between the three solids control systems was that two of them included chemical treatment of the centrifuge influent to enhance liquid\solid separation, also referred to as chemically enhanced centrifugation (CEC--see Section 5.5.6). The third system used no additional chemicals upstream of the centrifuge. The result was that separation of the colloidal solids from the liquid phase was much more efficient at the two sites using CEC. These samples were relatively free of suspended solids (TSS ranged from 24 to 520 mg/l), while the untreated sample had to be analyzed as a solid due to its solids content (23% to 24.7%), and had the consistency of a drilling fluid.

Table VII-5 compares data obtained from the two sites that used CEC to effluent limits established for this waste stream in a general permit covering drilling waste discharges in the coastal Gulf of Mexico region (58 FR 49126). The dewatering liquid at these sites was being treated for recycle and not for surface discharge. In fact, the majority of these waste volumes was hauled to commercial disposal.[1,2] The solids control contractor at one of these sites suggested that further treatment with activated carbon would produce discharge-quality effluent.[2]

TABLE VII-5. COMPARISON OF ANALYTICAL CHARACTERISTICS OF CENTRIFUGE WATER EFFLUENT FROM THE GAP ENERGY AND ARCO DRILLING SAMPLING EPISODES TO THE EPA REGION VI GENERAL PERMIT POLLUTANT LIMITATIONS FOR DRILLING OPERATIONS

Pollutant	Units	General Permit Limitations[a]		GAP Energy[1]		ARCO[2]	
		Texas	Louisiana	6/16/93	6/17/93	7/21/93	7/22/93
Oil & Grease	mg/l	15	15	ND(1.0)	1.0	8.0	3.0
TSS	mg/l	50	50	24	35	**520***	**440***
TDS	mg/l	3,000	--	**7,600***	**6,420***	**14,000***	**15,200***
COD	mg/l	200	125	**1,040***	**735***	**5,370***	**4,630***
pH	S.U.	6 - 9	6 - 9	6.27	8.95	7.48	7.4
Chloride	mg/l	500	500	317	**866***	**2,050***	**2,150***
Arsenic	mg/l	0.1	--	0.310	ND(0.018)	0.0766	0.0679
Barium	mg/l	1.0	--	ND(0.018)	2.32	0.667	0.696
Cadmium	mg/l	0.05-0.1	--	ND(0.004)	ND(0.002)	ND(0.005)	ND(0.005)
Chromium	mg/l	0.5	0.5	**1.26***	0.069	**4.59***	**4.42***
Copper	mg/l	0.5	--	ND(0.012)	ND(0.006)	0.23	0.141
Lead	mg/l	0.5	--	ND(0.044)	ND(0.022)	ND(0.047)	ND(0.047)
Manganese	mg/l	1.0	--	3.84	ND(0.003)	0.442	0.762
Mercury	mg/l	0.005	--	ND(0.0002)	ND(0.0002)	0.00115	0.00075
Nickel	mg/l	1.0	--	ND(0.026)	ND(0.013)	0.0279	0.0273
Selenium	mg/l	0.05-0.1	--	0.044	ND(0.0258)	ND(0.02)	ND(0.02)
Silver	mg/l	0.05	--	ND(0.010)	ND(0.005)	ND(0.004)	ND(0.004)
Zinc	mg/l	1.0	5.0	0.006	0.501	0.083	0.198

[a] 58 FR 49126

* Samples that exceed General Permit Limitations

4.4 COOK INLET DRILLING WASTE CHARACTERISTICS

For the purpose of developing compliance cost and pollutant reduction estimates, particular characteristics of drilling wastes in Cook Inlet, Alaska were identified. The sources for these data include the 1993 EPA Questionnaire for Coastal Oil and Gas Operators, the EPA Offshore Development Document, direct correspondence with the operators, and calculations and estimates based on the data

from these sources. Table VII-4 lists the characteristics of interest, including densities of cuttings and drilling fluid, percentage of solids in drilling fluid, and pollutant concentration data.

5.0 CONTROL AND TREATMENT TECHNOLOGIES

This section includes discussions of drilling waste treatment technologies currently employed in the coastal oil and gas industry. The technologies include the following:

- product substitution to minimize pollutant content
- closed-loop solids control systems to minimize waste stream volume
- reserve pits
- conservation and reuse/recycling.

In addition, EPA investigated the following disposal methods:

- land treatment/disposal
- subsurface injection of drilling fluids
- grinding and subsurface injection of drill cuttings

5.1 BPT TECHNOLOGY

EPA has developed effluent limitations guidelines for the Coastal subcategory based on Best Practicable Control Technology Currently Available (BPT), which represented the average of the best existing technologies at the time of investigation. These standards were promulgated on April 13, 1979 (44 FR 22069). At that time, EPA determined that drilling product substitution, or the use of more environmentally benign products, combined with onshore disposal was the best practicable control method available. An example of product substitution is the use of water-based drilling fluid in place of oil-based drilling fluid such that the drilling fluid (and cuttings) discharged would pass the no-free-oil limit. Effluent limitations based on this technology allow no discharge of free oil in drilling fluids and drill cuttings. This limitation is implemented by requiring no oil sheen to be present upon discharge.

5.2 PRODUCT SUBSTITUTION - ACUTE TOXICITY LIMITATIONS

It has been shown that low toxicities can be achieved through the use of water-based drilling fluids and low toxicity specialty additives.[4] Thus, limitations based on acute toxicity would encourage operators to substitute low toxicity additives for high toxicity additives. For the purpose of estimating

compliance costs and pollutant reductions, two options are presented that include toxicity based limitations (see Section X for detailed discussion of these options). One option includes the current offshore limitation of 30,000 ppm in the suspended particulate phase (SPP), which is currently met by all but 1% of the drilling wastes in Cook Inlet.[18] The other option includes a toxicity limitation of 1,000,000 ppm (SPP) which data from Cook Inlet discharge monitoring reports indicate is being met by 83% of the drilling wastes currently discharged.[19] The data supporting the 1,000,000 ppm toxicity limitation are presented in Section X.2.

5.3 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. During the development of the Offshore Guidelines, a statistical analysis of the API/USEPA Metals Database indicated that there is some correlation between cadmium and mercury and other trace metals in the barium.[9] Thus, regulating the concentration of cadmium and mercury in barite would indirectly regulate all other metals present in barite. The Offshore Development Document includes a detailed discussion of the findings of this analysis.[4]

5.4 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. Mineral oil has become a common substitute for diesel oil as it can be used as a torque-reducing agent and a spotting fluid.[4]

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.[20] The analysis revealed quantitative differences in the total aromatic, total sulfur and organic sulfur contents, as well as in the concentrations of individual aromatic hydrocarbons (benzene, naphthalene, biphenyl, fluorene and phenanthrene alkyl 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.[20] 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.

5.5 Enhanced Solids Control: Waste Minimization/Pollution Prevention

A widely recognized method of minimizing drilling waste volumes is the use of high-efficiency solids control systems, sometimes referred to as "closed-loop" solids control systems or CLSs. The term "closed-loop" is somewhat misleading in that it implies a closed system from which only waste cuttings are removed. The system is not truly closed because, regardless of the system's level of efficiency, some cuttings are always retained in the drilling fluid and some drilling fluid is always discarded with the cuttings.[21] While no single definition of the term "closed-loop" is available, definitions throughout current literature generally describe closed-loop technology as the process of minimizing both the amount of waste produced from an active drilling fluid circulation system and the amount of dilution required by the drilling fluid.[21,22,23] In practice, then, a CLS returns as much drilling fluid to the circulation system as is economically and practically possible. The drill cuttings removed from the circulation system are consequently reduced in liquid content and overall volume. While the practical application of solids control systems cannot be 100 percent "closed," the CLSs currently in use in the coastal oil and gas industry are measurably more efficient than conventional systems that utilize reserve pits and little or no waste minimizing technology.

Following is a list of advantages to using CLS technology compiled from current literature:[22,23,24]

- Reduced dilution and associated displacement of drilling fluid, resulting in reduced drilling fluid maintenance costs
- Reduced waste volume and disposal cost
- Reduced disposal costs offset increased costs for improved solids control
- Reduced total drilling location waste management costs

- Reduction or elimination of the need for an earthen pit and avoidance of significant site closure costs at land-based sites
- Increased rate of penetration
- Increased drilling efficiency through optimization of drilling fluid solids content and rheological properties
- Reduced trouble costs
- Minimal environmental impact
- Reduced waste transportation and disposal liability.

It is apparent in both industry literature and industry practices (as observed directly by EPA) that closed-loop solids control technology is achievable using currently available equipment.[1,2,3,22] A typical CLS consists of at least some of the following equipment, depending on the drilling program: shale shakers, a sand trap, a degasser, hydrocyclones (desanders, desilters, microclones), a flocculation chemical addition manifold, a dewatering centrifuge, and a barite recovery centrifuge if weighted drilling fluid is used. Closed-loop solids control systems can provide greater than 90 percent solids removal efficiency when flocculation enhancing chemicals are used.[25] Without chemical addition, CLS efficiency ranges between 72-75 percent.[25] The following sections describe these unit processes as they are currently utilized in closed-loop solids control systems.

5.5.1 Shale Shakers

Shale shakers, also called vibrating screens, are usually the first step in a solids control system. The function of a shale shaker is to remove the largest drill cuttings from the active drilling fluid system and to protect downstream equipment from unnecessary wear and damage from abrasion. Variables involved in shale shaker design include screen cloth characteristics, type of motion, position of screen, and arrangement of multiple screens.

Screen characteristics are expressed as mesh size (the number of openings in a liner inch), opening size, percent open area, and wire diameter. Typical mesh sizes range from 30 to 250.[26] The type of screen motion is determined by the eccentric weight or reciprocator (the vibrating device) and the suspension system. Motion can be circular, elliptical, or straight-line. Screen position depends on the effectiveness of the vibrating motion to move solids. Ideally, balanced circular or elliptical motion should move the solids across the screen regardless of screen position. Tilting the screen might be necessary

to overcome problems brought on by unbalanced elliptical motion. Such tilting can cause an increase in drilling fluid loss with the cuttings. Multiple screens are used when the solids load is too great for a single screen (or under other problematic drilling conditions), and are used in one of two arrangements: series or parallel. Staged (or "cascaded") screens in series are arranged so that the underflow of the first screen is the feed to the second, and so that the coarser mesh screen comes first. Parallel arrangements can include multiple screens on a single deck or side-by-side pairs of shale shakers. Some operators use two sets of shale shakers in series, wherein the first shakers, referred to as "scalp" shakers, contain coarser mesh to remove sticks and the largest particles, and the second set of shakers contain finer mesh.[25]

A term that is used to quantify the portion of solids that remain in the discharge as compared to the solids that leave with the liquid underflow is the "median cut." This term is used to describe the performance of all solids separation equipment in addition to shale shakers. The median cut-size particle for a shale shaker screen is that of which half pass through and half remain on the screen. For a given shale shaker (or any solids separation unit), a smaller median cut particle size indicates better separation than a larger median cut particle size. The range of acceptable median cut particle size depends on multiple factors for any particular unit. Factors that determine what the median cut will be for a given shale shaker include the screen mesh size, screen opening shape (square or rectangular), the amplitude (or distance) of the vibration, and the particle shapes. Not all particles smaller than the screen mesh get through, and likewise, some oversize particles pass through due to their shape.

Common shale shaker problems include solids overloading and screen plugging (called "blinding"). Both problems cause the screen to be bypassed and thus reduce the liquid throughput. Solids overloading, which may occur at times of increased drilling rate, can be overcome by adding a screen, either in series or in parallel. Blinding may be due either to a film of small particles that adheres to the screen and reduces the effective open area or to near-size particles plugging the screen. The former case may be corrected with a coarser mesh screen, and the latter might require a smaller mesh. Some shale shakers are equipped with a spray bar that showers water over the cuttings on the screen to enhance mud/cuttings separation. However, Cagel recommends that only temporary spray bars be used to apply a "mist" to sticky clay cuttings and other problematic solids.[27]

Current innovative screening device designs include fine mesh (up to 400) screens capable of processing drilling mud through an effective area of up to 600 square feet per second under a slight

vacuum. Advantages of such designs include improved degassing capability and reduced free liquid on the discarded solids.[28]

5.5.2 Sand Traps

A sand trap is a settling tank positioned to receive the liquid underflow from the shale shakers. This tank serves to "trap" sand and other large particles that bypass the shale shaker screens, either by design or due to a problem with the shakers (e.g., torn screen, blinded screen, solids overload). This settling protects the downstream equipment from wear due to abrasion. A properly designed sand trap is not stirred (as are other tanks in the active mud system), removes solids only through a bottom-opening dump valve, and discharges mud over a retaining weir. Because large amounts of barite could settle out in this quiescent tank, weighted muds should bypass the sand trap, unless there are problems with the shakers.[29,30]

5.5.3 Degassers

The purpose of a degasser is to remove gas and air from the drilling fluid which, due to its compressibility, can have detrimental effects on the drilling fluid. In addition, centrifugal pumps used to feed downstream equipment, as well as hydrocyclones, do not operate efficiently with gas-cut fluid. Therefore, in a well designed system, a degasser is positioned after the sand trap and before the hydrocyclone pumps.

Two basic designs of degassers include atmospheric and vacuum. Atmospheric degassers use turbulence to separate bubbles from the drilling fluid, and vacuum degassers use a combination of turbulence, thin film, and vacuum to perform the necessary separation. Available degasser performance data indicate that atmospheric degassers work satisfactorily on lower-weight, lower-viscosity water-based fluids as well as oil-based fluids.[31] Vacuum degassers perform better than atmospheric degassers on heavier fluids. However, when the yield point (a rheological property) of the drilling fluid is below 10 lb/100 ft,^{2} shale shakers can remove enough of the gas to make degassing equipment unnecessary.[29]

5.5.4 Hydrocyclones

The hydrocyclones used in drilling fluid circulation systems are static units that have no moving internal parts. Drilling fluid is fed tangentially into a hydrocyclone under pressure. Separation of the solid particles from the liquid occurs in these units by means of centrifugal forces imposed on the influent as it spirals down the inside of the cone, which causes the heavier particles to move radially to the outer

edge of the stream. The underflow solid particles exit through the bottom of the conical housing and the liquid overflow passes upward near the center and out through the top. Figure VII-1 illustrates the flow patterns within a properly operating hydrocyclone, as well as the nomenclature associated with hydrocyclone technology.

Hydrocyclones are typically referred to as "desanders" and "desilters," depending on the size particle they are intended to remove from the drilling fluid. Desanders are designed to remove particles down to 40 microns in size, desilters remove down to 20 microns, and specially designed "microclones" remove down to 10 microns (55 FR 23348). As a point of reference, human hair ranges in size from 30 to 200 microns. Particles less than two microns are referred to as "clay," particles from two to 74 microns are "silt," and particles greater than 74 microns are "sand.[29]" While there is no industry standard for the distinction, desander cones generally range in size from six to 12 inches in diameter, and desilter cones range from two to five inches.[32] The two-inch desilters are referred to as "microclones."

The cones of a desander are often arranged in two parallel rows of three each, for a total of six cones. The liquid overflow from each cone enters a header which returns the combined overflows to the next tank in the active drilling fluid system. Desilters often consist of two rows of six cones each. The number of cones required depends on the size of each cone and the type of solids being handled. Cones can also be arranged in a circle around a common header.

The problems experienced by hydrocyclones include clogged inlet or exit flow holes and improper flow adjustment. When the underflow opening is blocked, solids will exit the cone through the top with the liquid overflow and return to the active drilling fluid system. When the feed stream is blocked, the absence of the upward liquid flow can cause liquid overflow from adjacent cones to enter the cone from the overflow header and be lost through the underflow opening. If the flow rate is improperly adjusted, the hydrocyclone can become overloaded with solids, thus causing solid particles to exit with the overflow.

In the 1970's, "mud cleaners" were developed for weighted fluid systems for the purpose of capturing solids that exit through the hydrocyclone underflow, thus allowing the weighting agents existing with the solids to be returned to the system. A mud cleaner is a combination hydrocyclone-shale shaker designed to remove sand-sized particles while returning medium and fine silt as well as clay-sized material to the active drilling fluid system. One source states that the purpose of this separation step is to reduce the amount of barite make-up required by returning some solids that would otherwise be

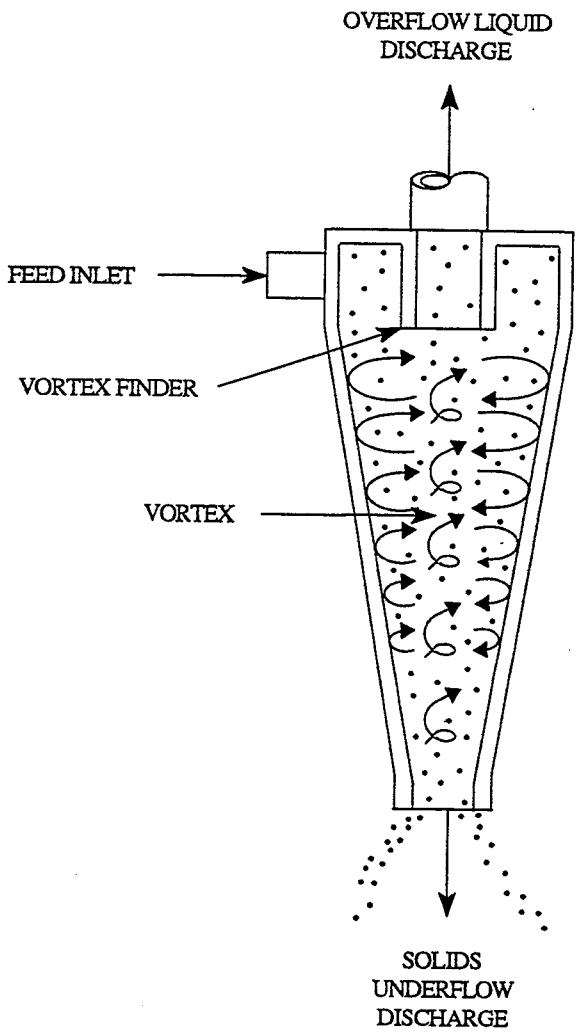


Figure VII-1
Hydrocyclone Flow Patterns

discarded by the hydrocyclone.[29] However, the return of the clay-bearing liquid should be stopped if viscosity becomes a problem. Another source states that the purpose of the mud cleaner is to remove any API sand (between 74 and 178 microns) that is not removed by the primary shale shakers, and offers guidelines for proper operation.[31] With recent improvements in shale shaker screens and hydrocyclone performance, the need for mud cleaners must be determined on a case-by-case basis.

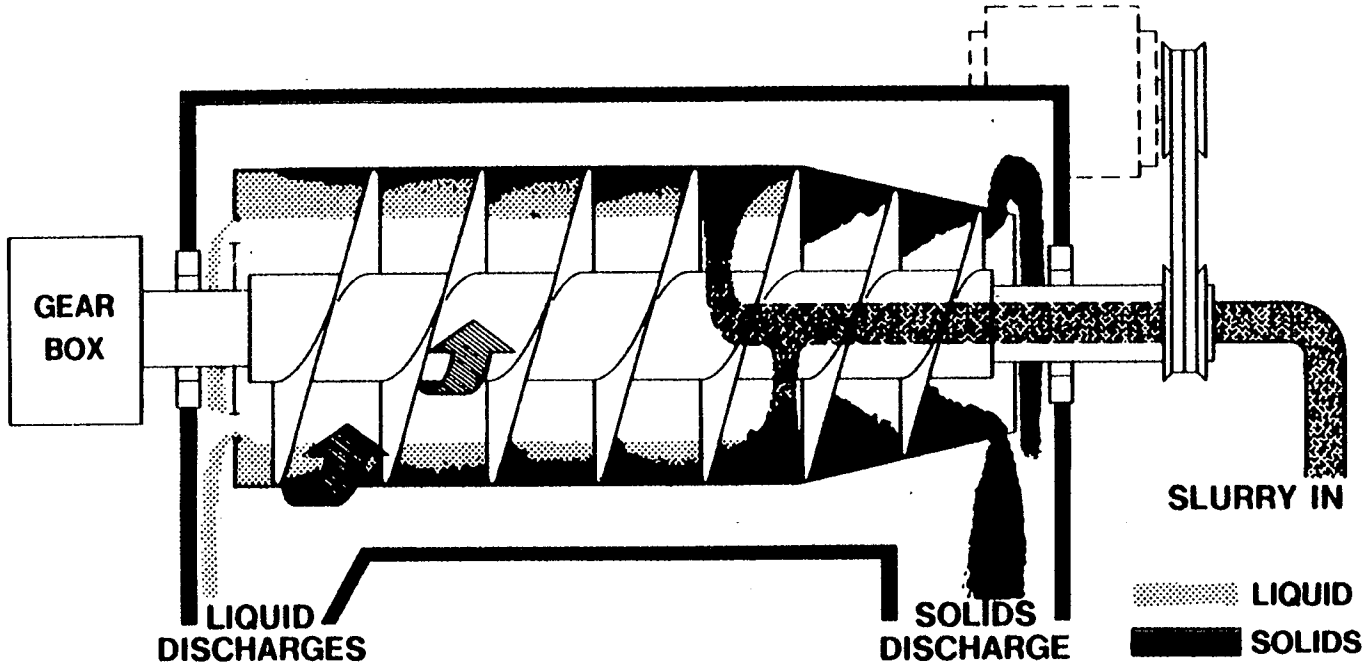
5.5.5 Centrifuges

Centrifuges are used in solids separation systems to enhance the solids removal efficiency. For example, use of centrifuges with standard rig equipment only, can boost a system's removal efficiency from 30 to 40 percent.[33] Two centrifuge designs are currently in use in the solids separation systems: decanting centrifuges and perforated rotor centrifuges (also called "RMS" for rotary mud separator).

Both the decanting centrifuge and the RMS can be used as "barite-recovery" units from which the barite-laden solids are returned to the active drilling fluid system while the liquid (dewatering effluent) is discharged or disposed. However, only the decanting centrifuge is used as a solids dewatering device, from which relatively dry solids (fine cuttings) exit to a waste pile and the liquid may be returned to the active drilling fluid system. The RMS is not capable of removing enough liquid from the solids fraction to be used as a dewatering step in a closed-loop solids control system.[25] Additional discussion regarding the applications of these units is included in the next section.

The decanting centrifuge, illustrated in Figure VII-2, is equipped with a spiral conveyor housed within a conical- or cylindrical-shaped bowl, both of which rotate in the same direction. The conveyor rotates at a slower speed than that of the bowl and the relative rotation between the two dictates the solids conveying speed. Bowl rotation speeds range from 1,500 to 3,500 rpm, and the conveyor speed is determined by the gear ratio, which may be controlled. A typical gear ratio is 80:1 where the conveyor loses one revolution per 80 revolutions of the bowl, such that a bowl speed of 1,500 rpm will correspond to a conveyor speed of 1,481 rpm and a relative conveying speed of 18.75 rpm. Retention time within the unit ranges between 10 and 80 seconds.[28]

The performance of a decanting centrifuge is measured by the feed rate capacity, the solids discharge capacity, and the liquid discharge capacity. The feed rate depends on the solids content of the feed, such that a feed with a high solids content will be limited by the solids discharge capacity, and a feed with a low solids content will be limited by the liquid discharge capacity. The solids discharge



Source: Gauthier Brothers Inc.

Figure VII-2
Decanting Centrifuge

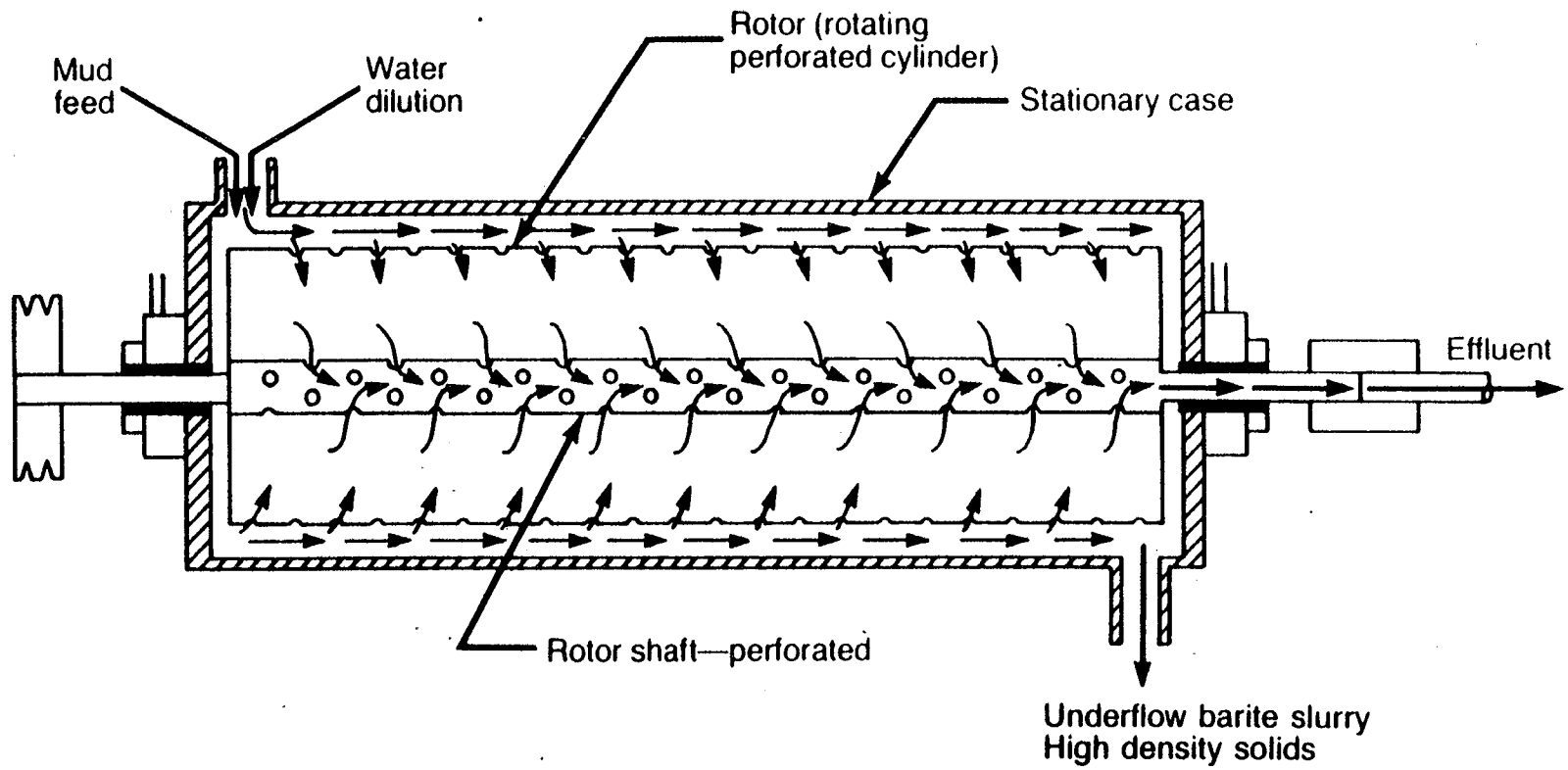
capacity depends on the rates at which solids are conveyed and discharged through the openings. The liquid discharge capacity depends on the capacity of the openings to discharge liquid of a certain depth within the bowl. A major development in decanter bowl design occurred in the early 1970's when a cylindrical or "contour" bowl was introduced. With this design, the increased bowl volume allows for a higher feed rate with the same separation achieved by a conical design. Due to their additional cost, contour bowl decanting centrifuges are typically used to dewater waste solids and recycle liquid back to the active system, rather than for barite recovery.[29]

The advantage of the RMS over the decanting centrifuge is that of portability. Because the solids-laden underflow is liquid, it exits the unit through a pipe, thus allowing the unit to be positioned anywhere in relation to the mud tanks. In contrast, a decanting centrifuge must be placed so that the solids fall directly into the receiving vessel (either the mud tanks or a waste container) or onto a solids conveyor.

Figure VII-3 illustrates the operation of a RMS. The feed enters the unit through an opening in the outer housing. The perforated rotor is the only part that rotates, causing the heavier particles to move radially toward the wall of the outer housing. The liquid overflow enters the rotor through the perforations and exits the unit through a pipe attached to the end of the rotor. The solids-laden underflow exits through a pipe located in the outer housing located at the opposite end from the feed inlet. The rate at which the underflow discharges is regulated by a choke valve in the discharge pipe. This choke also controls the amount of liquid exiting through the overflow discharge. Normal operation with a water-based fluid requires a dilution of ten parts feed mud to seven parts dilution water. This water must be compatible with the active drilling fluid. Disadvantages to the RMS, as compared to a decanting centrifuge, include a slightly higher barite loss, a high demand for dilution water, and a high rate of overflow discharge requiring disposal.[28] However, the smaller RMS is applicable in situations over water where there is no room to move a decanter around the mud tanks.

5.5.6 Chemically Enhanced Centrifugation

Chemically enhanced centrifugation (CEC) is a term used to describe the addition of coagulation and flocculation chemicals to enhance the effectiveness of a decanting centrifuge. CEC is also referred to as "dewatering" because its purpose is to remove as much of the liquid phase from the feed to a decanting centrifuge as is economically practical. The use of CEC systems is cited throughout current literature[23,34,35] and has been observed recently by EPA.[1,2] The CEC step is typically located where it can



Source: Gauthier Brothers Inc.

Figure VII-3
Rotary Mud Separator (RMS) Centrifuge

process the discharge from other solids separation equipment such as desilters, desanders, and barite-recovery centrifuges. The products of this dewatering step are a damp solid discharge and a clarified liquid discharge.

A CEC step is included in a CLS when it is necessary to remove colloidal particles (less than 5 microns) from the active drilling fluid system. If excess drill solids are not removed from a CLS, each pass through the system causes the particles to degrade to smaller sizes making them increasingly difficult to remove. The mechanical action of centrifugal pumps and shale shakers contribute to particle degradation. An undesirable increase in drilling fluid weight and viscosity can occur when drill solids degrade, due to the increased surface area of the smaller particles.[35] Increased surface area causes increased water consumption. Drill solids degradation can be controlled through the choice of drilling fluid and additives, which can consequently increase the efficiency of the mechanical solids control equipment. Additionally, removing colloidal solids with a CEC step prevents returning detrimental particles to the active drilling fluid system.

Chemical treatment is needed to remove low-gravity particles (below 5 microns in size) which are not removed by centrifugation alone.[35] These small particles must first be treated with coagulant to reduce the radius of their electric charge (called "zeta potential") which repels them from particles of like charge. Flocculent is then added to allow the coagulated particles to come together (or "bridge") into larger groups of particles that can be removed by a decanting centrifuge. High molecular weight polyacrylamides are commonly used for flocculation.[36]

The degree to which the discharged liquid is clarified depends on its intended disposition, either as recycle back to the active drilling fluid system, or as waste to be disposed in some manner (including annular injection, surface discharge, or off-site disposal). The solids discharged from a CEC unit are typically 35 to 75 percent water by volume.[23] If the discharged liquid is to be returned to the active drilling fluid system, it must be compatible with the drilling fluid.

Finally, it is important to note that onsite dewatering of spent drilling fluid is typically practiced only when an economical onsite method of disposal or reuse is available for either the dewatering liquid or the dewatered solids. Such methods include onsite land disposal of the solids and injection of the liquid into either the annulus of the well being drilled or an available disposal well. When an economical means of disposing or reusing the products of dewatering is not available, the least expensive method of

handling these wastes is to remove the dewatering step and haul the spent drilling fluid to an offsite disposal facility.

5.5.7 Closed-Loop Solids Control System Design

To better understand the design of a closed-loop solids control system, it is important to discuss the basic applications of each unit in relation to the active drilling fluid circulation system. Table VII-6 describes various applications of solids separation equipment used with unweighted and weighted drilling fluid systems.[29] The distinction between whether a separation step is primary or secondary is determined by the origin of the feed stream to a particular unit: a primary separation step is fed directly from the active drilling fluid circulation system, and a secondary step is fed from a primary step. Also of concern is whether a separation unit is designed to handle a flow rate equal to the total drilling fluid circulation rate ("full" flow) or a fraction thereof ("partial" flow).

As shown in Table VII-6, the location of a centrifuge within a solids control system varies depending on its application. Both decanting and RMS centrifuges can be located as primary separation units when used to recover barite from a weighted drilling fluid. In this primary application, the centrifuge processes the entire volume of recycled drilling fluid. A decanting centrifuge, the only centrifuge useful for dewatering purposes, may be located in a secondary position to receive either desilter underflow or barite recovery centrifuge overflow. This secondary separation step processes only a fraction of the total drilling fluids system volume.

Figure VII-4 illustrates a system in which the shale shakers, degasser, desander, and desilter, are operated in primary full-flow, and the decanting centrifuge is operated as secondary separation of the hydrocyclone underflow. This example is an unweighted drilling fluid application. The system arrangement illustrated in this figure is typical of CLSs used to minimize solid waste volume and to recycle water back into the active drilling fluid system. Table VII-6 demonstrates that there is often more than one piece of equipment capable of performing a given separation task. The choice of equipment is usually the result of an analysis weighing the drilling program operating parameters and conditions against overall cost. Current literature cites the fact that poor choices of solids separation equipment were prevalent in the 1980s due to a general misunderstanding of the operating principles of each unit[27, 29] Ormbsy, 1983). However, it is apparent that more operators are taking a closer and more careful look at solids separation technology as a means of reducing drilling fluid make up costs as well as drilling waste generation and costs.

TABLE VII-6
SOLIDS SEPARATION EQUIPMENT APPLICATIONS [a]

Item	Type of Equipment	Separation	Type of Flow	Character of the Discard	Application(s)
1	Shale shaker screens	Primary	Full	Wet to damp	Remove coarsest particles (cuttings) and protect downstream separation units. Use with both unweighted and weighted fluids.
2	Desanding hydrocyclones	Primary	Full	Wet	Remove sand-size particles (down to approx. 40 microns). Use with both unweighted and weighted fluids. With oil-base fluids, use only when followed by items 7 or 8.
3	Desilting hydrocyclones	Primary	Full	Very wet	Remove silt-size particles (down to approx. 20 microns). Use with both unweighted and weighted fluids.
4	Decanting centrifuges	Primary	Partial	Low-volume liquid	Remove clays and soluble materials (in free liquid overflow) for viscosity control in a weighted water-base fluid. This application is often called a "barite-recovery" centrifuge. Mis-application if used on unweighted fluid or on oil-based fluids.[b]
5	Perforated rotor centrifuges	Primary	Partial	Medium-volume liquid	Remove clays and soluble materials (in free liquid overflow) for viscosity control in a weighted water-base fluid. This application is often called a "barite-recovery" centrifuge. Mis-application if used on unweighted fluid or on oil-based fluid.[b]
6	Special barite cyclones	Primary	Partial	High volume liquid	Remove clays and soluble materials (in free liquid overflow) for viscosity control in a weighted fluid. With oil-base fluids, use only when followed by items 7 or 8. Mis-application if used on unweighted fluid.
7	Decanting centrifuges	Secondary	(Desilter underflow)	Damp	Dewater solids from hydrocyclone underflow and return free liquid overflow to the drilling fluid system. Useful in areas where 1) water is expensive, or 2) solid waste minimization is necessary. Mis-application if used on weighted fluid.
8	Decanting centrifuges	Secondary	(Barite recovery overflow)	Damp	Dewater solids from barite recovery overflow and return free liquid overflow to the drilling fluid system. Useful in areas where 1) water is expensive, or 2) solid waste minimization is necessary.
9	Special screens	Secondary	(Desilter underflow)	Wet to damp	Remove selective solids from hydrocyclone underflow and return free liquid overflow to the fluid system. This application is called a "mud cleaner" when used on a weighted fluid, and is intended to reduce barite usage. Usually a mis-application if used on an unweighted fluid.

a. Adapted from Ormsby, 1983.[29]
b. Another industry source reports using barite-recovery centrifuges on weighted mud regardless of whether it is water base or oil base.[37]

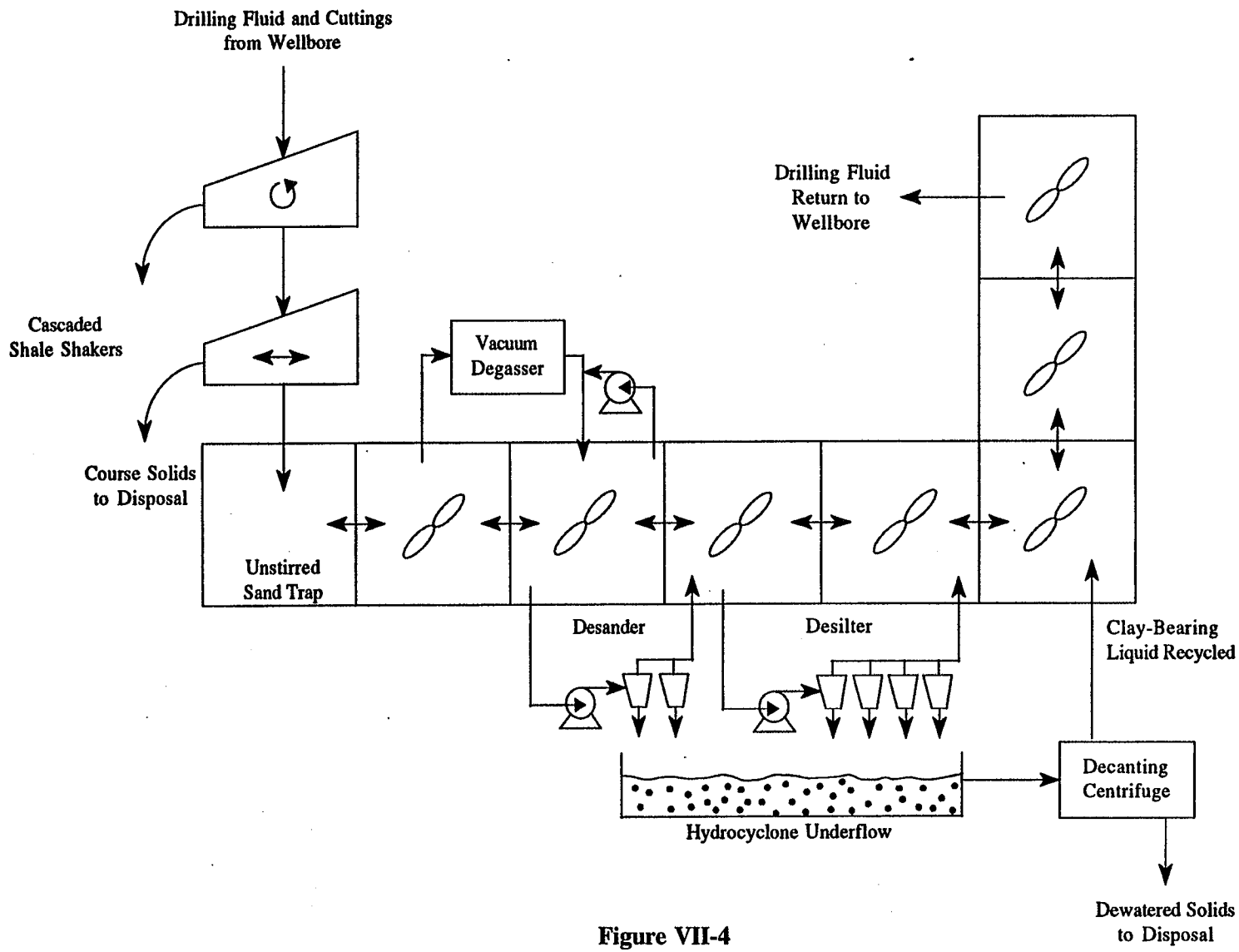


Figure VII-4
Example Closed-Loop Solids Control System
(Unweighted Drilling Fluid Application)

CLS systems change with operating conditions, even during the same drilling operation. For example, a CLS might consist of multiple shale shakers, hydrocyclones, and a dewatering centrifuge during the drilling of the surface interval of the hole where an unweighted water-base fluid is used and the rate of drill cuttings production is greatest. Then as the fluid is weighted up and the rate of penetration decreases, one of the shale shakers might be removed and a barite-recovery centrifuge might replace the desilter. If a formation of reactive clay is reached, flocculation chemicals and associated equipment might be added at that point. Examples of these and other CLS design considerations are cited in current literature.[38]

EPA recently visited three drill sites in southern Louisiana, each of which utilized closed-loop solids control technology.[1,2,3] Figures VII-5, VII-6, and VII-7 depict the solids control systems used at the three sites. The CLS used at the GAP Energy drill site (Figure VII-5) included a CEC step to separate water from spent drilling fluid for recycle back into the active drilling fluid system. A unique feature of the GAP site is that in addition to the solids control equipment provided with the drilling rig, another suite of solids control equipment was brought onsite by the solids control contractor. Depending on the requirements of the drilling program, it is not uncommon for the solids control contractor to substitute part or all of the rig-supplied equipment. The ARCO drill site (Figure VII-6) included a barite recovery centrifuge and a CEC step to separate and recycle water from the barite recovery centrifuge overflow. Chemical addition was minimized at ARCO to keep fluid treatment chemicals in the recycle water. Thus, the water samples obtained from the dewatering centrifuge at the ARCO site were significantly darker than the water samples obtained at the GAP site. Based on visual inspection, samples from both sites were free of settleable solids. The CLS system used at the UNOCAL site (Figure VII-7) was similar to the ARCO system, except that no chemicals were added to the feed to the dewatering centrifuge. By comparison, then, the water sample from the UNOCAL site was considerably more turbid than the samples obtained at the other sites, containing total solids ranging from 23% to 24.7%.[3]

5.5.8 Solids Control System Efficiency

Table VII-7 lists solids control system efficiencies from various literature sources. These numbers are not statistically comparable due to the lack of information available regarding the methods by which they were calculated. However, it is interesting to observe that efficiency increases dramatically for systems using chemically enhanced centrifugation over those relying only on mechanical means.

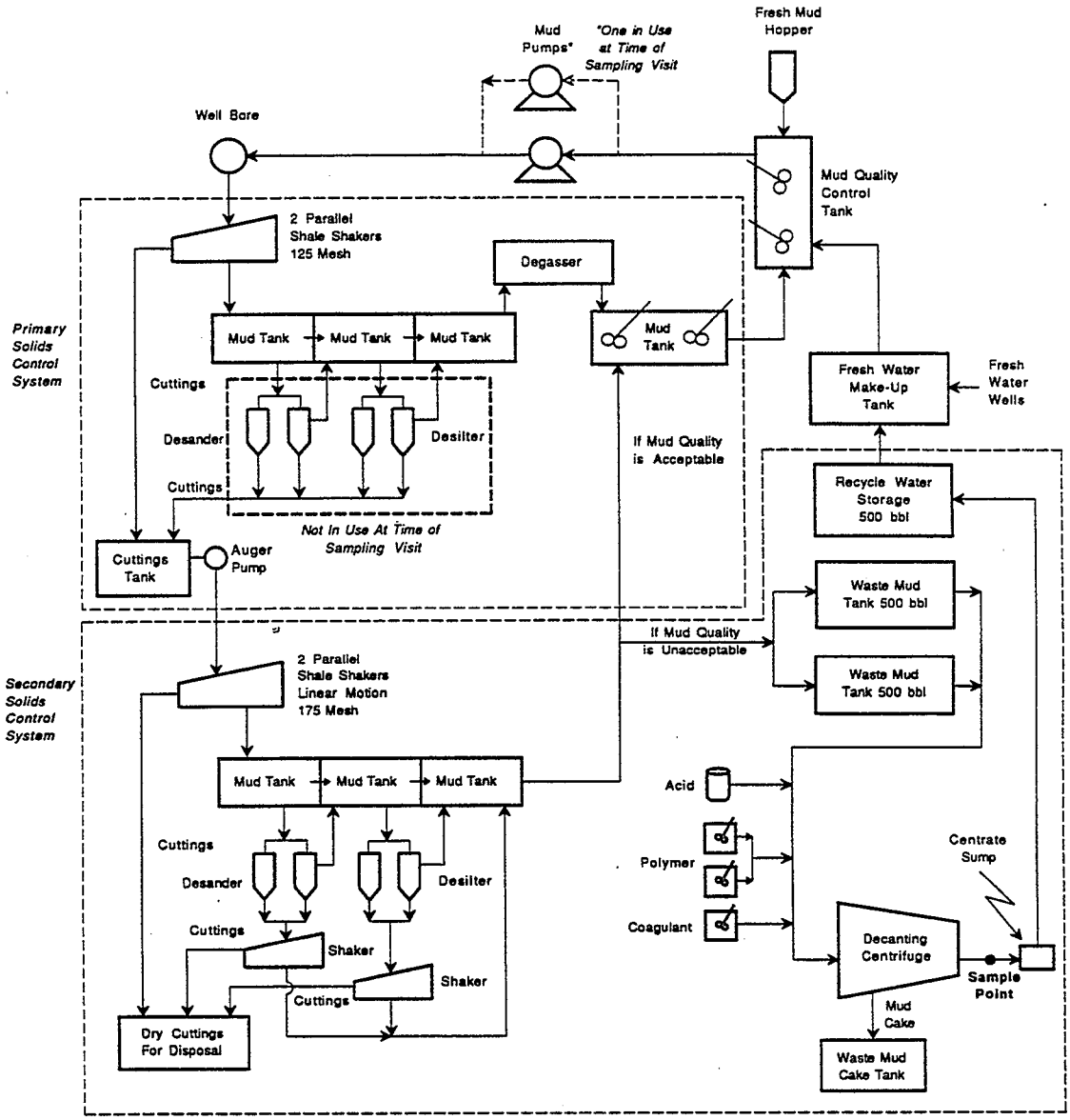


Figure VII-5
GAP Energy Mud Recirculation and Solids Control System

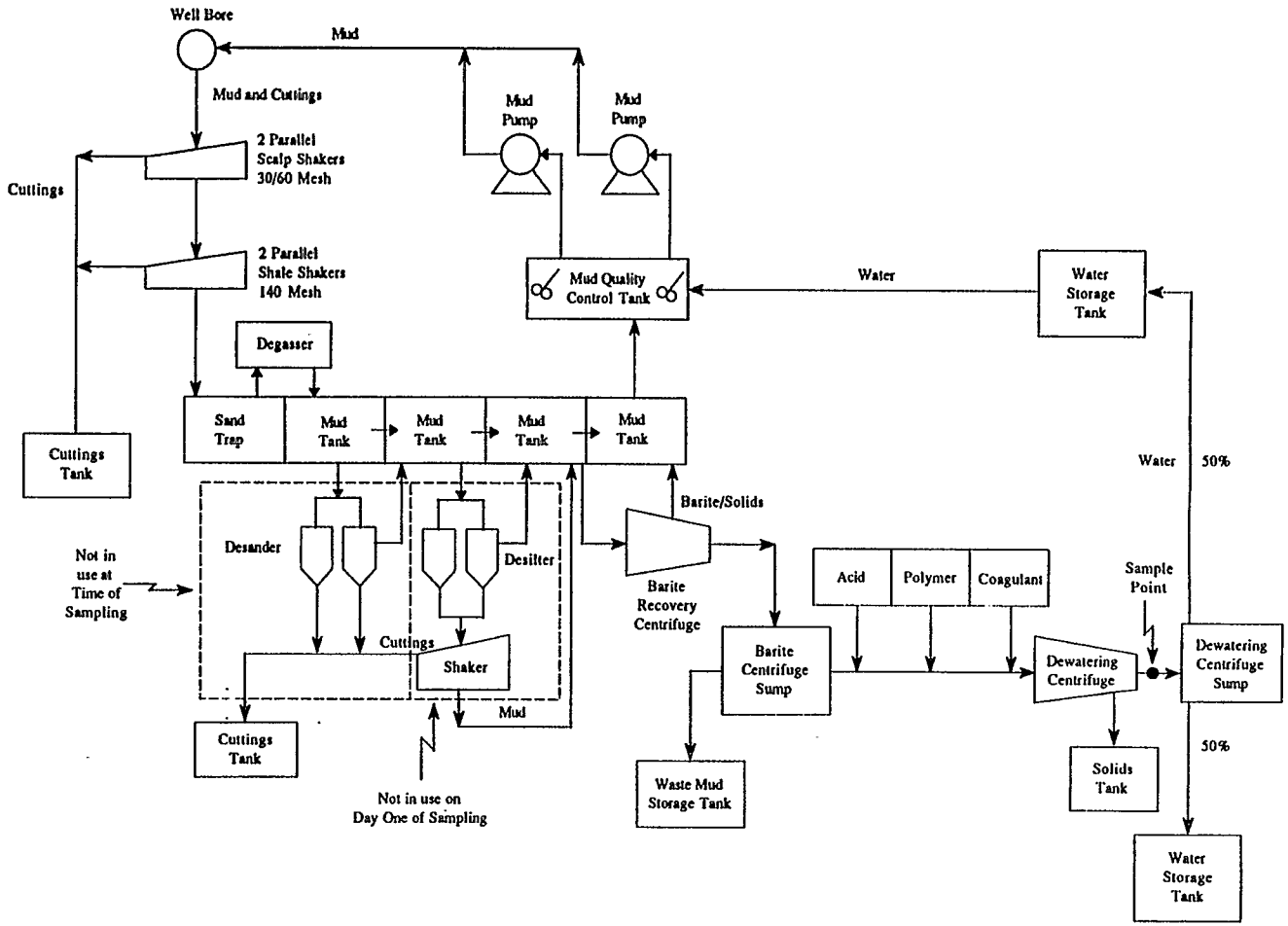


Figure VII-6
ARCO Mud Recirculation and Solids Control System

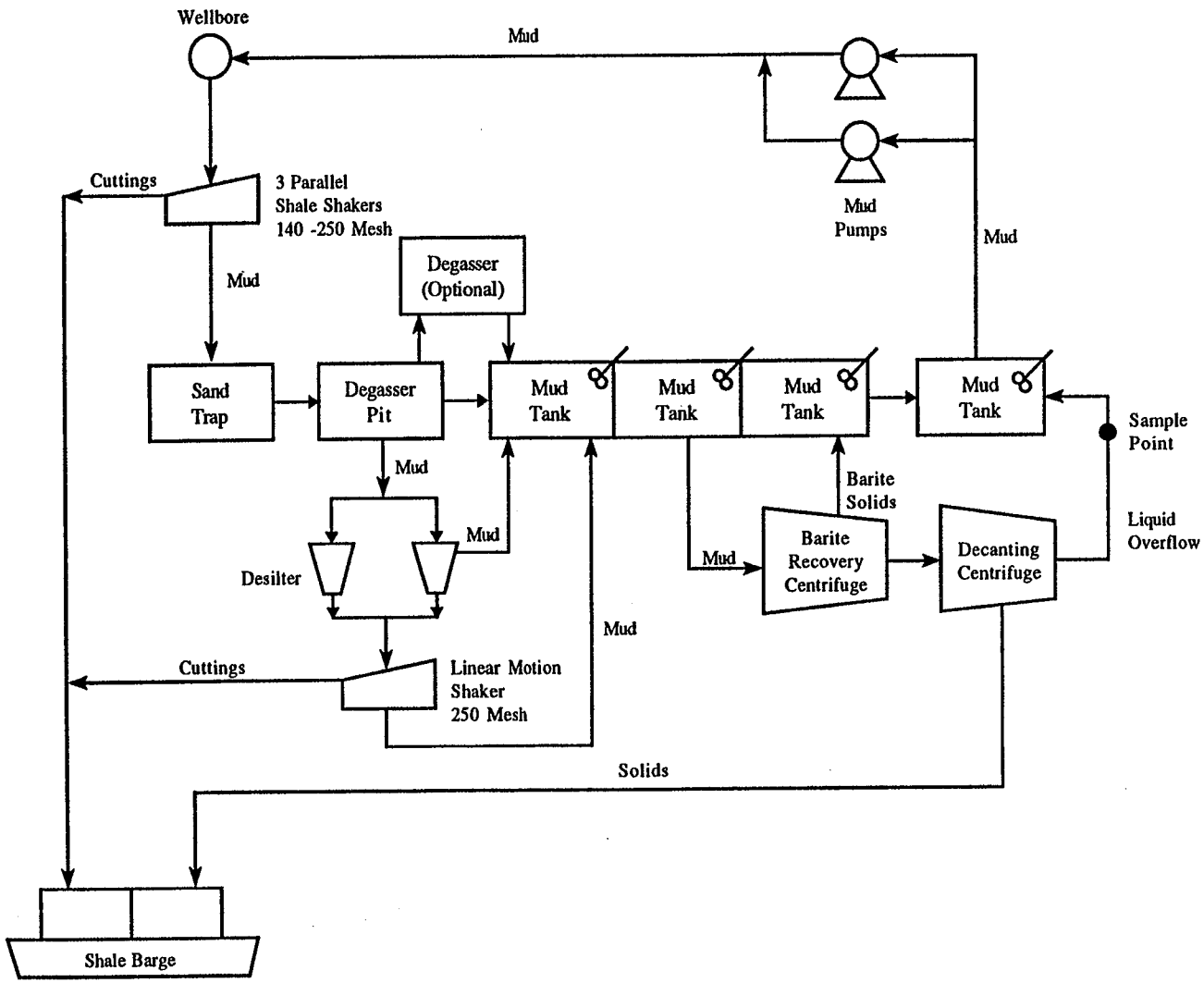


Figure VII-7
UNOCAL Mud Recirculation and Solids Contol
for 11,700 ft to 13,500 ft

TABLE VII-7
CLOSED-LOOP SOLIDS CONTROL SYSTEM EFFICIENCIES

Source	Equipment Used[a]	Reported Efficiency (vol. %)
Walters, 1991[33]	1	31.13
Walters, 1991[33]	2	37.58
Walters, 1991[33]	1	30.40
Walters, 1991[33]	3	88.31
Walters, 1991[33]	3	87.97
Walters, 1991[33]	1	21.73
Walters, 1991[33]	2	45.53
Finke, Aug. 18, 1993[25]	4	72-75
Finke, Aug. 18, 1993[25]	5	>90
Wojtanowicz, 1988[41]	6	99.967[b]
Wojtanowicz, 1988[41]	6	99.945[b]

[a] Classes of equipment:

1: Rig shale shakers, desander, and desilter only.
2: Rig equipment plus rental mud cleaner and centrifuge.
3: Unitized system: 2-4 parallel shale shakers, desander mud cleaner, desilter mud cleaner, microclone, low-speed centrifuge, and high-speed centrifuge.
4: Unitized system: two sets of shale shakers (in series), desander mud cleaner, desilter mud cleaner, and dewatering centrifuge.
5: Same as 4 plus flocculation chemicals and finer hydrocyclones.
6: Dewatering centrifuge and flocculation chemical addition only

[b] Wojtanowicz studied different sizes of dewatering centrifuges with flocculation chemical addition and reported the best two efficiencies observed as measured by weight % of the solids in the centrifuge liquid effluent compared to the centrifuge feed.

The difference in CLS efficiencies with and without chemical addition was apparent from the systems observed during EPA's three drill site visits. All efficiencies reported by the solids control contractors at these sites are general values for the equipment used, as illustrated in Figures VII-5, -6, and -7. None of the efficiencies were directly measured on-site. The solids control contractors at both the GAP and ARCO sites reported efficiencies of approximately 90% when chemical flocculation was used.[1,2] The contractor at the ARCO site estimated efficiencies of 72-75% for the same equipment when chemicals are not added.[2] Similarly, an efficiency of 75% was reported for the system used at the

UNOCAL site, where chemical flocculation was waved due to the availability of annular injection of the decanting centrifuge overflow.[2]

For the purpose of calculating compliance cost estimates, the control technology method that included closed loop solids control assumed an efficiency of 69%, based on data received from operators in Cook Inlet in response to the 1993 Coastal Oil and Gas Questionnaire.[6] Details of this and other CLS assumptions are discussed in Section X.5.2.

5.6 RESERVE PITS

Although their use is being phased out in much of the coastal Gulf of Mexico region, reserve pits are still employed within the coastal subcategory. A reserve pit is an earthen pit (lined or unlined) that is used to contain drilling fluids and wastes such as drill cuttings, discharges from solids control equipment, location drainage, drilling fluid, excess cement, equipment wash-down water, and completion/workover fluids. In addition, the pit contents can be used as reserve fluids in the event that the drilling fluids in the active system are lost to the formation.[23,39] Different types of earthen pits (lined or unlined) are used at land-based drilling sites to manage both solid and liquid materials and wastes.

Pit construction is based on the volume of waste to be placed in the pit. When sizing the pit, the smallest practical volume should be used. This minimizes the size of a land-based drilling location. In addition to drilling wastes, the reserve pit also accumulates precipitation, thus a smaller pit will accumulate less over the course of drilling operations. An industry source indicated that the pit should be designed using the assumption that two barrels of drilling waste will be generated for every foot of hole drilled.[40]

The pit must also be designed to prevent migration of pit contents. This is achieved through the use of adequate berm (levee) height to maintain freeboard in the pit to prevent overflow of pit contents. Louisiana regulations specify that a minimum two feet of freeboard be maintained in the pit at all times (Louisiana Administrative Code, Statewide Order 29-B). In addition, the material used in pit construction must have a low permeability to prevent the pit contents from leaching during the course of drilling operations. If soil of adequate permeability is not available at the drilling site, the pit can be lined.

In terms of site layout, two types of approaches to reserve pit construction are documented in current literature. The following sections discuss conventional reserve pits, which are the historically

traditional approach to land-based drilling waste management, and "managed" reserve pit systems, which reflect current industry efforts to segregate and minimize wastes at the drill site.

5.6.1 Conventional Reserve Pits

In a conventional reserve pit system, one pit is used to contain all of the drilling wastes at the drilling location. These wastes may include drill cuttings, spent drilling fluid, location drainage, excess cement, equipment wash water, and completion/workover fluids. A footprint area of 200 feet by 300 feet would normally be required for a conventional reserve pit at a drilling location with an approximate well depth of 14,000 to 18,000 feet.[42] Assuming a levee ten feet wide encloses the pit, the actual surface dimensions of the pit would be 180 feet by 280 feet. Pit construction companies indicate that the average conventional reserve pit is 200 feet by 200 feet.[43,44] The pit is generally five to six feet deep but depths of eight and ten feet are also used.[44] The depth is limited by the height of the water table. Figure VII-8 is a layout of a typical drilling location where a conventional reserve pit has been used to manage drilling fluids and wastes. Pit construction companies also indicate that they are frequently asked to segment or partition the conventional reserve pits.[43,44]

5.6.2 Managed Reserve Pits

The following text is adapted from a paper presented by EPA at the SPE/EPA Exploration and Production Environmental Conference held in San Antonio, Texas in March 1993.[45]

A managed reserve pit is a waste segregation system that uses two or more pits to prevent contaminated wastes from coming in contact with uncontaminated materials. This can occur when using a conventional reserve pit while drilling into salt formations, if the well experiences a salt-water kick, or if oil-based fluid or fluid containing barite is used for drilling.[46] The number and size of the individual pits or cells depend on the number and volume of distinct waste streams expected to be generated during drilling operations. For instance, one cell would be sized and constructed as the reserve pit to accommodate the volume of drilling fluid required for the operation plus an adequate freeboard. A second cell would be constructed to manage cuttings, a third cell for rainwater runoff which may also be used for rig wash and drilling fluid make-up water. An important design consideration of the managed reserve pit system is to ensure that natural communication between the cells is prevented. The transfer of material between pits is handled using a dragline or manually controlled pumps.

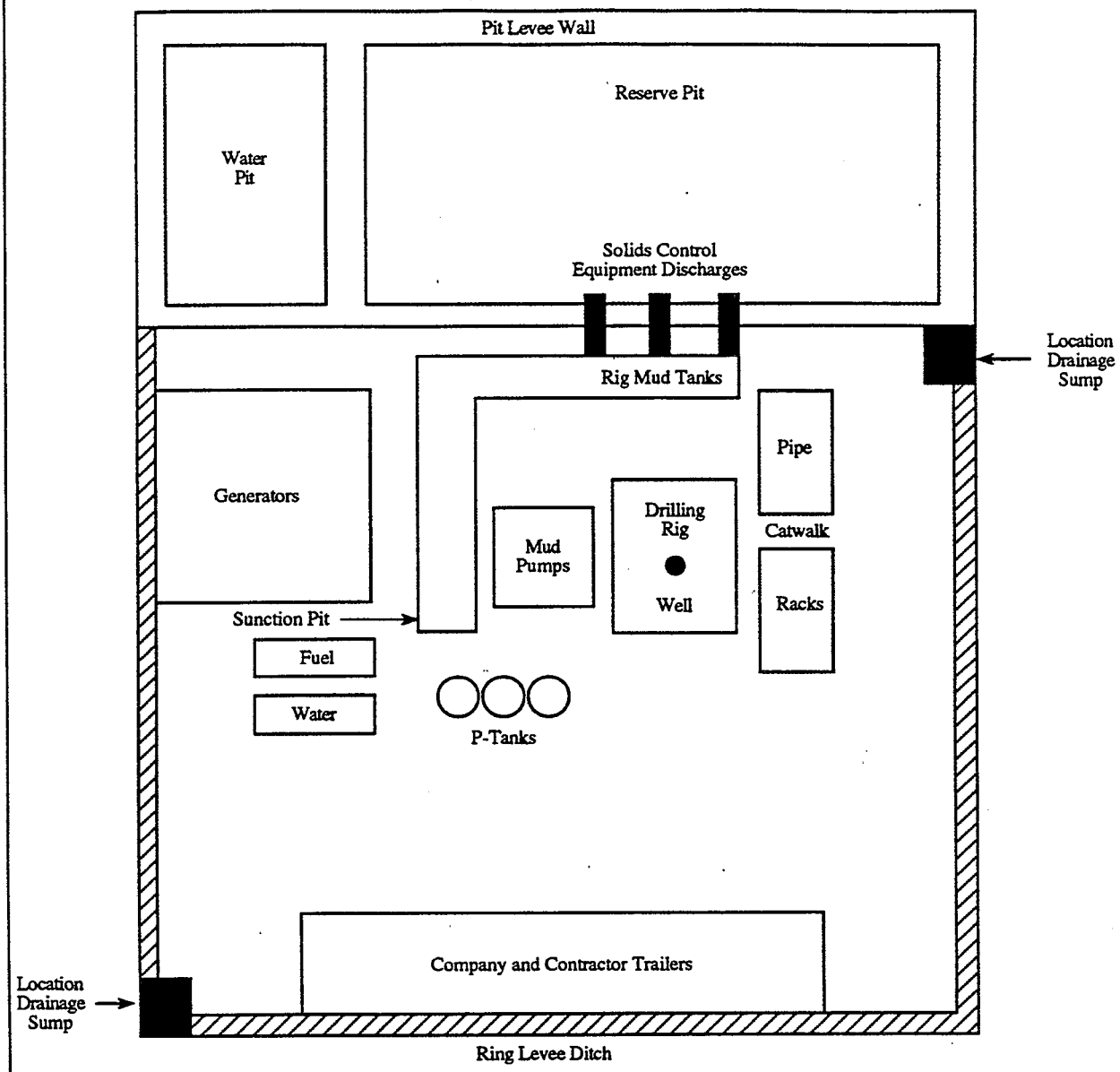


Figure VII-8
Layout of a Drilling Location Utilizing a Conventional Reserve Pit

The entire managed reserve pit system can be constructed in an area that would be occupied by a conventional reserve pit.[42] Thus, while the overall footprint of the managed pit system is comparable to that of a conventional reserve pit, a benefit is derived from keeping contaminated waste separated from waste that might be recycled, reused, or disposed of at a lower cost.

The operation of a managed reserve pit system is summarized as follows.[42] Solids and residual drilling fluids are discharged to the shaker pit from the solids control equipment. Solids from the shaker pit are transferred to the storage pit and fluids are transferred to the settling pit along with rain water and equipment wash water. Following settling, the water is transferred to the treatment pit. Reserve pit treatment often includes lime addition to raise the pH, followed by aeration by mixing the pit contents. Such treatment clarifies the water by causing the solids to settle out. From the treatment pit, water is recycled for continued use in the drilling operations or discharged. The status of the managed pit system is evaluated on a daily basis and consists of assessing the volume of wastes in the system and the distribution of these wastes among the pits in the system.

5.6.3 Pit Closure and Site Restoration

The regulations in the States of Louisiana and Texas specify requirements for pit closure and approved disposal methods for pit contents (Louisiana Statewide Rule 29-B; Texas Statewide Rule 8). The closure and disposal requirements (applicable to conventional and managed reserve pits) include:

- Dewatering and backfilling
- Solidification
- Landfarming and backfilling
- Injection (liquids)
- Burial on-site (solids)
- Treatment and discharge (liquids)
- Off-site commercial disposal.

Disposal of drilling wastes can be accomplished via on-site annular injection, on-site landfarming or burial,[23,43] injection into a dedicated UIC Class II disposal well (either on- or off-site) or hauling off-site for land application at either a centralized commercial facility or a non-commercial site.

Following disposal of pit contents by any of the methods mentioned above, the reserve pit(s) is backfilled with the earthen levee material and/or stockpiled soil from initial excavation of the pit(s). The area may then be graded and restored to predrilling conditions.[42,47]

5.6.4 Reserve Pits on the North Slope

Reserve pits have been the drilling fluids and cuttings disposal method of choice on the North Slope since drilling began in that region. A discussion of the use of reserve pits and other land disposal methods unique to Alaska is included in the document entitled "Oil and Gas Exploration and Production Wastes Handling Methods in Coastal Alaska".[48] However, the North Slope operators have recently ceased using reserve pits and now rely on a grinding and injection system for drilling waste, described in detail in Section 5.10.

5.7 Conservation and Reuse/Recycling

The emergence of the closed-loop solids control system has provided operators with one of the best means of reducing wastes generated and increasing recycling opportunities. Additionally, reuse and recycle is particularly desirable for fluids that have a hydrocarbon (diesel or mineral) liquid base because they are expensive and cannot be discharged. 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.

5.8 Land Treatment and Disposal

This section discusses land-based treatment and disposal methods for drilling wastes at onsite and centralized commercial land treatment and disposal facilities. In addition, this section discusses current land disposal methods in Cook Inlet, Alaska.

5.8.1 Onsite Landfarming

Onsite landfarming of drilling wastes is a potential option in cases where there is adequate space, the soil conditions are suitable, and the oil company is the land owner or has permission from the land owner to landfarm.

The landfarming process consists of spreading a thin layer of the drilling waste over the landfarm area. After spreading the drilling waste, the top soil and humus layer that was stripped in the preparation phase of the drill site is spread over the drilling waste with a nitrogen fertilizer. The drilling waste, topsoil, and fertilizer are mixed through cultivation with a set of disks or a tractor-mounted tiller. The cultivation/fertilizer cycle is repeated about twice a year for two or three years. The time period is dependent on the quantity and the concentration of the drilling waste applied to the soil and the size of the application area.[49] The area can be successfully re-vegetated once the hydrocarbon content in the soil is less than one percent and the chloride content in the soil is less than 1,000 ppm.[49] Seed germination studies have revealed that landfarming operations can be re-vegetated within 180 days.[50]

Microbial decomposition is the major cause of hydrocarbon reduction in landfarming, although evaporation and volatilization of the light-end hydrocarbons is probably significant.[50] To maximize microbial decomposition, the most important aspects of landfarming are to maximize the surface contact between the drilling waste and soil bacteria, to aerate the soil/drilling waste mix to promote aerobic decomposition, and to boost the soil microbe count by providing additional nutrients in the form of high nitrogen fertilizer. The two commonly used fertilizers are 34-0-0 and 11-51-0 (nitrogen-phosphorous-potassium ratio). Fertilizer application rates are typically on the order of 1,000 pounds per acre.[49]

EPA's costing analysis of drilling waste disposal (Section X) did not include onsite landfarming, but rather assumed that all wastes would be sent injected onsite (see Section 5.10) or sent to commercial disposal facilities (see below).

5.8.2 Centralized Commercial Land Treatment and Disposal Facilities

Centralized commercial facilities for non-hazardous oil field wastes (NOW) are treatment and disposal and/or processing facilities that are located offsite from the drilling operation and are generally not operated by an oil and gas operator. In Louisiana, the Department of Natural Resources permits NOW facilities and in Texas, the Texas Railroad Commission permits NOW facilities.

Centralized commercial treatment facilities receive drilling wastes in vacuum trucks, dump trucks, cuttings boxes or barges. In Louisiana, the transportation of drilling wastes in barges is common because of the high frequency of drilling projects occurring in coastal waters. One major commercial waste treatment facility in Louisiana has treatment facilities with barge access and several transfer stations with barge access.[51]

Most of these facilities employ a landfarming technique whereby the wastes are spread over small areas and are allowed to biodegrade until they become claylike substances that can be stockpiled outside of the landfarming area. Another common practice at centralized commercial facilities is the processing of drilling waste into a reusable construction material. This process consists of dewatering the drilling waste and mixing the solids with binding and solidification agents. The oil and metals are stabilized within the solids matrix and cannot leach from the solids. The resulting solids are then used as daily cover at a Class I municipal landfill. Other potential uses for the stabilized material include use as a sub-base for road construction and levy maintenance.[52]

The treatment process most often employed at land treatment facilities consists of a cycle which includes application, treatment, certification, and excavation. The treatment phase is designed to address heavy metals, sodium imbalances in the waste, chloride concentrations in excess of the state regulatory limits, oil and grease concentrations in excess of the regulatory limits and moisture contents. Commercial landfarming facilities typically treat waste in cells designed for a particular amount of waste. When the maximum amount of waste has been applied to a cell, the treatment process begins.[53]

The landfarming treatment process for one commercial NOW facility located in southeast Louisiana is described in the following paragraphs.[51,53]

The treatment cells at this facility range in size from 1.5 to 6 acres and consist of above-ground-level structures surrounded by berms built up to a height of 6 to 8 feet. Topsoil is removed prior to cell construction. Clay deposits under the topsoil serve as natural barriers to groundwater contamination. The clay acts to prevent cell leachate drainage to groundwater and to prevent groundwater infiltration into cells where there is a high natural water table.

The application phase of treatment consists of filling the cell with incoming drilling waste. The maximum application that the state of Louisiana allows is 15,000 barrels per acre over a three month period. Approximately 20 tons per acre of gypsum or calcium sulfate is spread and mechanically mixed with the waste. Through a classic ion exchange chemical reaction, the calcium from gypsum or calcium sulfate replaces the sodium on the soil particles. This step is necessary in reducing the exchangeable sodium percentage (ESP) of the soil. The ESP is a measure of the number of exchange sites on the soil particles which are occupied by sodium ions. The Louisiana regulations for landfarming limit the ESP concentration to 25 percent.

The next step of the treatment phase is flooding of the cell to remove the soluble salts from the soil-waste matrix. Approximately 6 to 12 inches of water is pumped onto the cell and mixed with the waste with mechanical equipment. The higher salt concentrations in the waste drive the concentrations up in the fresh water, thereby lowering the concentrations in the waste. Once the chloride concentrations reach an equilibrium and the water ceases to absorb more salts (at approximately 1,500-2,000 ppm), the solids are allowed to settle out of the water and the water is pumped out of the cell into a surface impoundment prior to injection. The salt removal step is an important step in maximizing the biodegradation process because many microorganisms do not function well in a high salt environment. The treatment process has taken about four to six months at this point.

The next step of the landfarming process consists of treatment of the oil and grease content of the waste. The oil and grease content is lowered by mixing the waste with the soil and through biodegradation. This treatment step consists of cultivation of the soil/waste mixture to improve exposure to the sun and air which maximizes biodegradation. The matrix in the cell is cultivated twice a month for a period of six to eight months.

Once all the material in the cell is treated and all the analytes are below the state-required limitations, the "cleaned" clay-like product is transferred from the cell to a stockpile area onsite. This material is used to maintain or construct new berms around the cells.

5.8.3 Cook Inlet Land Disposal

There are currently no commercial land disposal facilities permitted in Cook Inlet. There are however, several non-commercial waste disposal facilities available to some Cook Inlet operations. These are: Marathon Landfill at Kustatan (west side of Cook Inlet), UNOCAL grinding and injection wells in Kenai gas field (project discontinued due to mechanical failure of the injection well), and UNOCAL Beaver Creek Landfill on the Kenai Peninsula. Marathon and UNOCAL jointly operate the disposal site at Kustatan, located 3 miles north of the Trading Bay facility.[68] Table VII-8 summarizes the waste disposal options available to operators in Cook Inlet.

The site at Kutatan is a landfill used for the disposal of drilling wastes and tank bottoms. This facility services the same platforms as do Trading Bay and Granite Point facilities.[68] The landfill consists of lined cells into which wastes are placed and stabilized. The size of the landfill is 16 modules, each module containing 4 lined cells, for a total size of 64 cells. Each cell can hold approximately 2,000 cubic

TABLE VII-8

SUMMARY OF WASTE DISPOSAL OPTIONS FOR OPERATORS IN COOK INLET[68]

Operator	Solid Waste Disposal Site	Location	Capacity	Restrictions
Marathon	Kustatan Waste Disposal Site	West side of Cook Inlet	615,680 bbl	Limited to waste generated in the Trading Bay unit by Marathon and Unocal
	Beaver Creek Waste Disposal Site	Beaver Creek Production Facility	14,000 cu yds (remaining)	Limited only for wastes generated at Beaver Creek (federal wildelife refuge)
	Clean Soils, Inc. (rotory kiln) - private company	West side of Cook Inlet	Max.: 40 tons/hr feed rate	Used for solids only (dewatering required).
Unocal	Kustatan Waste Disposal Site	West side of Cook Inlet	615,680 bbl	Operating agreement with Marathon
	Kenai Gas Field	West side of Cook Inlet	Pilot project	Project stopped in 1993 due to downhole mechanical failure
Shell Western	Only commercial sites in the lower 48 states	--	--	--
Phillips	Only commercial sites in the lower 48 states	--	--	--
ARCO	Only commercial sites in the lower 48 states	--	--	--

yards or 9,620 bbl of material, for a total capacity of 615,680 bbl. Once a cell has reached full capacity, it is covered and closed. When one module reaches capacity, a new module is developed.[68] To date, only 19,240 bbl of wastes have been disposed at Kustatan.[69] This facility is only accessible and operated in the summer months because of its location and of the harsh climate conditions in Cook Inlet. Due to the shallow waters on the west side of Cook Inlet, only barges can be used to transport the wastes to the west side of Cook Inlet for disposal.

5.9 SUBSURFACE INJECTION OF DRILLING FLUIDS

Subsurface injection of spent drilling fluids is an established oil field practice. If the solids control system at a well includes a dewatering step, the resulting liquid stream may also be injected if it is not being recycled into the drilling fluid system. Subsurface injection can be either through the annulus of an existing casing system, as shown in Figure VII-9, or into a UIC Class II injection well. The process consists of pumping the fluid down hole into a receiving formation. Prior to injection, drilling fluids are typically screened using a shale shaker to remove any large particles. The typical drilling fluid injection system consists of a shale shaker, mud tank, and pump. Triplex (three-plunger) pumps are commonly used as injection pumps. Maintenance of all flow rates, pressures, and injection zones is the responsibility of the oil company in accordance with the requirements of the permit. Annular injection is not feasible in cases where there is a bad cement job or in areas where there is potential of affecting a sensitive production zone.[54]

5.10 GRINDING AND SUBSURFACE INJECTION OF DRILLING WASTE

The process of grinding and injection of drilling muds and cuttings was developed by operators on the North Slope Alaska in mid-1980's. This process is currently being used on the North Slope for the injection of spent drilling fluids and cuttings. EPA has recently learned that several similar projects have also occurred or are planned in coastal areas in the Gulf of Mexico and California,[55] and in the North Sea[56] for the injection of drilling fluids and cuttings. The following sections discuss these projects.

The critical parameters that affect the performance of any grinding and injection system are: drilled solids particle size, the injectable fluid density and viscosity, percent solids in the injectable fluid, injection pressure, and the characteristics of the receiving formation. These parameters and their effect on the design of the grinding and injection system are discussed in detail in the following sections.

5.10.1 Cuttings Processing System and Injection

The cuttings grinding system consists of three separate unit processes: screening, grinding, and slurrification. On the North Slope, cuttings are first conveyed to a large triple-deck classifier where the cuttings are washed with high pressure water to remove residual drilling fluid and are sorted according to size. The underflow from the classifier, which contains particles smaller than 74 microns, and the washwater are sent to the injection slurry pit. The overflow, which contains particles larger than 74 microns, are further processed in a ball mill grinding unit.[57]

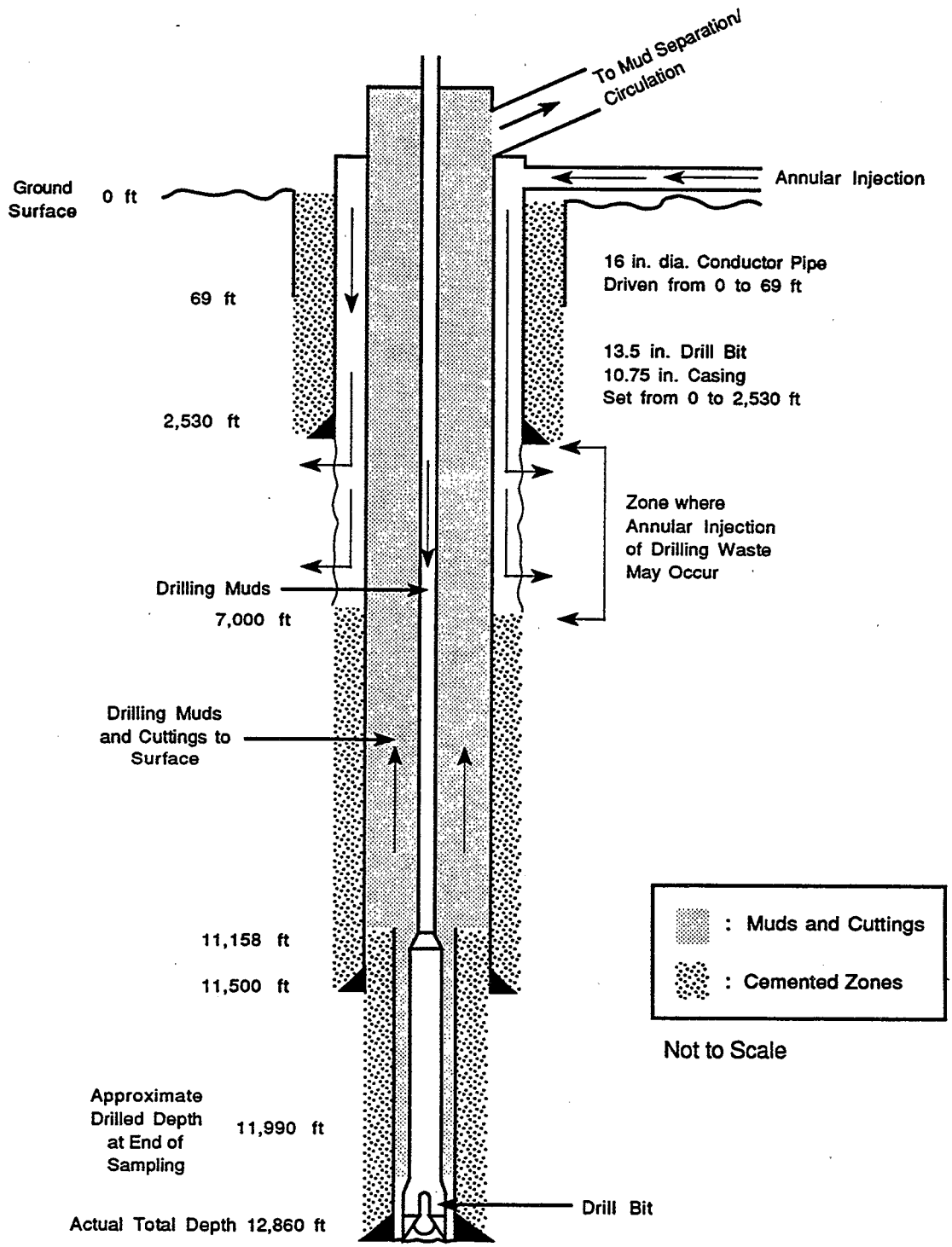


Figure VII-9
Annular Injection During Drilling

The grinding unit is a 30-inch by 34 inch chamber that contains 3,000 lb of 1.5-inch forged steel balls. The cuttings are fed into this chamber for size reduction. In order to achieve the required particle size, the chamber is vibrated at 1,200 cycles with and amplitude of 3/4 inch.[57] After size reduction in the ball mill, cuttings are pumped to a hydrocyclone for further classification. Particles larger than 74 microns are returned to the ball mill for repeated grinding, while particles smaller than 74 microns are sent to the injection pit.

The injection pit has a capacity of 500 barrels and is mechanically agitated to maintain a homogeneous slurry. Chemicals such as bentonite and extenders are added to the pit to increase the solids carrying property, or viscosity of the injection fluid. The injection fluid is typically maintained at a funnel viscosity of 100 seconds per quart.[57]

The final step of this process is the injection system. Ground and slurried cuttings are pumped from the injection pit to the injection pump(s) by hard chrome-lined centrifugal pumps.[57] The centrifugal pumps have a pumping capacity of 500 gallons per minute (gpm). BPX uses a pair of positive displacement piston injection pumps, each with a pumping capacity of 210 gpm. These are 165-horsepower (hp) triplex pumps driven by a 150 hp electric motor through a four-speed gearbox. The injection pressure varies between 600 to 1,000 psi depending on the weight of the fluid being injected. Typically, the density of the injection fluid is maintained within 10 to 11 pounds per gallon (ppg) with a solids content of 25 to 30%.[57]

Successful grinding and injection projects in the Gulf of Mexico coastal region were cited by one company licensed to perform this technology.[58] Drill cuttings generated from drilling operations in the coastal Gulf of Mexico region often consist of bentonitic shale formations which break up easily when hydrated and subjected to high shear pressures. Because of these cuttings properties, the grinding and injection systems employed in the Gulf of Mexico coastal projects take advantage of the transfer pumps' shear force for size reduction.[59] Freshwater or seawater are added to the cuttings stream before and after size reduction. After size reduction, the cuttings slurry is further mixed with freshwater or seawater so that the injectable fluid has a funnel viscosity of 70 to 90 seconds per quart and a density of 11 to 12 ppg.[58]

Similar grinding and injection processes were successfully tested on other drilling fluid systems, mainly on oil-based fluids and cuttings.[56,60,61] With the new grinding and injection technology available and proven on oil-based fluids and cuttings, the use of oil-based fluids followed by grinding and injection

may prove in some cases to be more economical than land disposal, thus further reducing the overall well cost. The cuttings processing systems employed on these projects are similar to the system used on the North Slope. Variations of this process consist of the type of screens used, elimination of cuttings washing systems, and the type of grinding equipment used. Rotating ball mills instead of vibrating ball mills have been successfully used on offshore platforms. Although rotating ball mills are high maintenance pieces of equipment, they are usually employed on offshore platforms for grinding large and relatively high density material. Vibrating ball mills are not typically used on offshore platforms because of the possible structural impact of the weight and of vibration.[13,56]

Cuttings washing is practiced only where water-based drilling fluids are used in drilling operations, such as on the North Slope, because of the potential reuse of these cuttings as construction material.[57]

5.10.2 Receiving Formation Evaluation--North Slope Operations

The injection mechanism for solids-laden fluids differs from that used for solids-free liquids such as produced water. Produced water is injected at a pressure that does not fracture the receiving formation. On the North Slope, successful cuttings injection operations demand that a fracture be created in the receiving formation before injection of the cuttings slurry can occur. Without a fracture, the solids in the slurry would quickly plug up the pore spaces in the formation.[62]

Therefore, the success of the grinding and injection technology depends on the proper selection of the receiving formation. In general, the desired characteristics of the receiving formation are to be unconsolidated, of high porosity (typically 20%), high permeability (typically 0.5 Darcy) material of sufficient thickness (typically 33 feet) and at a sufficient depth not to affect the surrounding environment. The specific values, however, change for different drilling locations.[63]

Injection of a homogeneous cuttings slurry can be achieved through a dedicated wellbore or through the annular space between a string of casing and the exposed formation. The slurry is pumped at a specified rate into the wellbore or the annulus. When the downhole pressure of the fluid exceeds the formation pressure, the formation fractures and the cuttings slurry flows into the fissure. The pumping operation continues until all slurry is injected into the formation.

The optimum injection pressure depends on the characteristics of the receiving formation, and should be continuously monitored. The mechanisms of inducing a fissure in the formation, such as its mode of propagation, its size, its containment, and its impact on nearby wellbores, should be well understood before injecting the cuttings slurry. Fracture modeling can be used to estimate the size and shape of the injection fracture. A new 3-dimensional model has been developed to optimize the design of hydraulic fractures and to simulate drill cuttings injection.[64]

Subsurface geology of the North Slope is uniform throughout the area, making disposal of drilling wastes by injection an attractive alternative to land disposal. North Slope geologic stratification is more suited to injection because of the shale and sandstone formations, and because of the permafrost which underlies most of the North Slope.

Shale, which is composed entirely of clays, is a relatively plastic and low permeability rock. These properties make it a good confining zone. The fracture gradient for shale ranges from 0.8-0.9 psi/ft. For comparison purposes, sandstone (a rock composed of sand sized rock and mineral fragments) has a fracture gradient of 0.55-0.65 psi/ft.[65] The lower the fracture gradient, the easier the formation will fracture. Therefore, sandstone is a better receiving formation than shale because it fractures more easily, while shale is a better confining formation.

Of importance to the oil and gas operations on the North Slope is the continuous permafrost which descends from the surface to depths between 1,000 and 2,000 ft.[57] The permafrost provides a low permeability barrier so that the injected wastes do not migrate upward towards the surface.

5.11 Availability of Injection Wells

As stated above, the uniformity of the underlying geology of the North Slope makes injection of drilling wastes a viable disposal method throughout in that area. In Cook Inlet, Alaska, drilling wastes were injected during a 1994 project at a platform operated by Shell, thus demonstrating that injection zones are available in Cook Inlet.[66] In the coastal Gulf of Mexico area, a statistical analysis of the responses to the 1993 Coastal Oil and Gas Questionnaire indicates that 122 new production drilling projects, or 65% of the 187 new production wells drilled in 1992,[6] utilized annular injection for disposal of drilling wastes.[67]

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SECTION VIII

PRODUCED WATER— CHARACTERIZATION, CONTROL AND TREATMENT TECHNOLOGIES

1.0 INTRODUCTION

The first three parts of this section describe the sources, volumes, and characteristics of produced water from coastal oil and gas production activities. The final 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 water (brine) brought up from the hydrocarbon-bearing strata during the production of oil and gas. 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 is 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 coastal oil and gas industry. The total volume of produced water being discharged by the coastal oil and gas industry is 227.5 million bpy (or 623,000 bpd). The volume of wastewater generated by the oil and gas 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 hydrocarbon fluid production at a given well or production facility. In general, the percent of produced water volume to oil and gas 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 generally greater for facilities producing oil or a combination of both oil and gas as compared to gas-only facilities. The volume of produced water at a given facility 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.

As discussed in Section IV, the entire volume of produced water generated in the North Slope region of Alaska and the coastal region of California is injected for waterflooding, and therefore will not be discussed in this section. In addition, in the Gulf of Mexico states of Florida and Alabama, all coastal facilities inject their produced water, primarily for disposal, and therefore, are not discussed in this section. Produced water characteristics for those coastal areas discharging it (i.e., Cook Inlet, Alaska and Texas and Louisiana) are discussed below.

3.1 GULF OF MEXICO

For the Gulf of Mexico region, the three sources of data that are available for produced water volumes are: the 1993 Coastal Oil and Gas Questionnaire database, the Gulf of Mexico state permit discharger database and the 1992 EPA 10 production facility data. These three data sources are discussed in detail in Section V. Because the Coastal 308 Questionnaire was not a census, the data concerning produced water volumes and other parameters from the survey were statistically extrapolated as estimated industry-wide averages. The Gulf of Mexico state permit discharging facilities database contains comprehensive facility-specific data, but only includes facilities that are discharging. The 1992 EPA 10 production facility study contains data from only 10 selected facilities that primarily inject produced water. The following is a summary of the produced water flow data from these three sources.

According to the statistical analysis of the EPA 1993 Coastal Oil and Gas Questionnaire, hereafter referred to as the coastal questionnaire statistical results, the average produced water generation rate from a coastal facility was 1,923 barrels per day (bpd) for facilities that inject produced water and 2,069 bpd for facilities that surface discharge produced water.[1]

Table VIII-1 presents the produced water volumes, treatment systems information, and hydrocarbon production from the production facilities sampled in EPA's 10-facility study. Details of this

Table VIII-1
Characteristics of the 10 Production Facilities Sampled by EPA[26]

Operator Name	Field Name	Oil/Condensate (bpd)	Gas (MMcf/d)	Brine (bpd)	Treatment Technologies Prior to Injection
Greenhill Petroleum	Bully Camp	1,050	11	8,000	Settling Tanks, Cartridge Filters
Oryx Energy	Chacahoula	213	24	3,000	Settling Tanks
Exxon Corporation	Clam Lake	518	0	7,500	Settling Tanks
Oryx Energy	Caplen	186	35-50	3,559	Settling Tanks
Texaco	Sour Lake	300	0	11,500	Settling Tanks
Texaco	Port Neches	210	0	4,000	Settling Tanks*
Arco	Bayou Sale	1,485	62.2	6,150	Settling Tanks, Parallel Plate Coalescer
Texaco	Bayou Sale	2,381	29.4	6,462	Settling Tanks, Cartridge Filters
Badger Oil Corp.	Larose	200	0	2,500	Settling Tank, Screen Filter
Texaco	Lake Salvador	950	25	7,000	Setting Tanks, Cartridge Filters
Average	-	749	19.4	5,967	-

* No injection at this site.

study are discussed in Section V.4. All of these facilities, except for Texaco Port Neches, disposed of their produced water via subsurface injection. As can be seen from this table, no correlation is apparent between oil or gas production and produced water volumes.

Appendix XI-3 presents the database of the 216 coastal discharging facilities in the Gulf of Mexico. As can be seen from these data, produced water volumes for discharging facilities range from 1 bpd to 144,000 bpd. The average produced water volume for discharging facilities is 2,265 bpd. The total volume of produced water discharged in the Gulf of Mexico is 489,237 bpd.

3.2 ALASKA

Table VIII-2 presents the produced water volume and treatment data for Cook Inlet. As noted in Section IV, there are five platforms that discharge directly into Cook Inlet while the remaining nine pipe their combined production fluids (hydrocarbon and water) to one of three shore-based separation/treatment facilities. The total volume of produced water discharged from platforms in Cook Inlet is 1,860 bpd, and the overall total including the three shore-based facilities is 134,182 bpd. The three shore-based facilities discharge approximately 96 percent of the Cook Inlet produced water, not including the Dillon platform discharges.

4.0 PRODUCED WATER COMPOSITION

Since the 1979 promulgation of the Coastal Oil and Gas BPT Effluent Limitations Guidelines, EPA has conducted several produced water characterization studies. A number of these studies were used in the development of the 1993 Offshore Guidelines. These studies are the 30 Platform Study, the California Sampling Program, and the Alaska Sampling Program, and are described in detail in the Offshore Development Document.[2] Therefore, data from these studies will not be presented individually in this document. In some cases, data summarized in the Offshore Development Document have been used in the tables presented in this section, particularly with respect to certain treatment system performance data and the composition of produced water in Cook Inlet. For the Gulf of Mexico region, the EPA 10 Production Facility Study is the source of produced water composition data. Separate discussions on the characteristics of produced water and the databases used are presented for both the Gulf of Mexico and Cook Inlet regions.

TABLE VIII-2 PRODUCED WATER VOLUMES FOR OIL AND GAS PRODUCTION FACILITIES IN COOK INLET REGION[3]

Facility Name	Operator	Avg. Prod. Water Vol. (bpd)	PW Disch. Location	Treatment Technologies
DISCHARGING PLATFORMS				
Dillon	Unocal	2,650[a]	Platform	Skim Tanks
Bruce	Unocal	160	Platform	Skim Tanks
Anna	Unocal	1,500	Platform	Skim Tanks
Baker	Unocal	30	Platform	Skim Tanks
Tyonek "A"	Phillips	170	Platform	Skim Tanks, Gas Flotation
SHORE BASED TREATMENT/DISPOSAL FACILITIES				
Granite Point	Unocal	300	Spark Platform	Skim Tanks
Trading Bay	Marathon	126,072[b]	Outfall	Skim Tanks, Gas Flotation, Settling Pits
E. Foreland	Shell Western	3,300	Outfall	Skim Tanks, Corrugated Separators
Total		134,182	-	-

[a] Dillon platform was not discharging as of the time of EPA's cost analysis. Recent information indicates that it is currently discharging.[4] During 1991 the discharge volume was 2,650 bpd.

[b] This value is the sum of volumes reported individually for each platform contributing to the Trading Bay facility reported in SAIC, January 6, 1995.

4.1 Composition of Produced Water for the Gulf of Mexico

The 1992 EPA 10 Production Facility Study characterizes BPT-level produced water effluent for the coastal region of the Gulf of Mexico. Although samples were collected at a number of locations within each facility, samples collected at the effluent of the settling tanks were most representative of BPT level treatment.

Table VIII-3 presents the overall summary of occurrence of the organic pollutants detected in the 20 samples of settling tank effluents that were collected. As can be seen from this table, only benzene and toluene were detected in 100 percent of the samples and o&p-xylene, 2-propanone, ethylbenzene, m-xylene and phenol were detected in greater than 50 percent of the samples. An additional 28 organic pollutants were detected in the range from 5 percent to 50 percent of the samples. Out of a total of 232

TABLE VIII-3
PERCENT OCCURRENCE OF ORGANICS FOR SETTLING TANK EFFLUENT SAMPLES FROM THE 1992 EPA 10 PRODUCTION FACILITY STUDY[5]

Pollutant	Units	Number of Independent Samples	Number of Independent Samples w/ Detects	Percent Detects
Benzene	µg/l	20	20	100.0
Toluene	µg/l	20	20	100.0
o+p Xylene	µg/l	20	16	80.0
2-Propanone	µg/l	20	16*	80.0
Ethylbenzene	µg/l	20	15	75.0
m-Xylene	µg/l	20	14	70.0
Phenol	µg/l	20	11	55.0
n-Hexadecane	µg/l	20	10	50.0
Naphthalene	µg/l	20	10	50.0
o-Cresol	µg/l	20	10	50.0
2-Butanone	µg/l	20	10	50.0
Benzoic Acid	µg/l	20	9	45.0
Hexanoic Acid	µg/l	20	9	45.0
n-Tetradecane	µg/l	20	9	45.0
p-Cresol	µg/l	20	9	45.0
n-Decane	µg/l	20	8	40.0
n-Dodecane	µg/l	20	8	40.0
2,4-Dimethylphenol	µg/l	20	8	40.0
n-Octadecane	µg/l	20	7	35.0
n-Eicosane	µg/l	20	6	30.0
2-Hexanone	µg/l	20	6	30.0
2-Methylnaphthalene	µg/l	20	6	30.0
Trichlorofluoromethane	µg/l	20	3	15.0
Benzyl Alcohol	µg/l	20	2	10.0
Methylene Chloride	µg/l	20	2	10.0
n-Docosane	µg/l	20	2	10.0
n-Hexacosane	µg/l	20	2	10.0
n-Tetracosane	µg/l	20	2	10.0
Vinyl Acetate	µg/l	20	2	10.0
1,2:3,4-Diepoxybutane	µg/l	20	2	10.0
Bis(2-Ethylhexyl) Phthalalte	µg/l	20	1	5.0
Chloromethane	µg/l	20	1	5.0
Di-n-Butyl Phthalate	µg/l	20	1	5.0
n-Octacosane	µg/l	20	1	5.0
n-Triacontane	µg/l	20	1	5.0

* Two of the 16 detected samples of 2-Propanone were greater than the upper limit of the calibration range.

priority and non-conventional organics analyzed, 197 were not detected.

Table VIII-4 presents summary analytical data of the settling tank effluents from the 1992 EPA 10 Production Facility Study. Only pollutants that were detected in at least one sample were reported. Any non-detected sample results were given the value of one-half the detection limit value in the derivation of the overall mean values. These data were used as BPT-level effluent concentrations for the Gulf of Mexico region in the development of the Coastal Guidelines.

4.2 Composition of Produced Water for Cook Inlet

Table VIII-5 presents the summary data obtained from several sampling programs that are considered to be representative of the composition of produced water in Cook Inlet. The primary source, a comprehensive Cook Inlet Discharge Monitoring Study was conducted by EPA Region 10 to investigate oil and gas extraction point source discharges.[6] In this study, produced water discharges from production facilities in Cook Inlet (coastal subcategory) were sampled and analyzed for one year, from 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. Flow-weighted averages were then calculated using the mean concentrations from each discharge in this study. This study, however, only provided data for 10 organic pollutants and zinc. Concentrations for the other pollutants included in Table VIII-5 were taken from the BPT-level effluent data from the Offshore Development Document.[2] EPA determined it appropriate to apply effluent data for offshore platforms to these in Cook Inlet because of the similarities in operation. The data for Radium 226 and 228 are from the Alaska Oil and Gas Association's comments on the offshore rulemaking.[7]

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 state and NPDES permits that allow the discharge of coastal produced water to surface water bodies with limits only for the oil and grease content (BPT limitation) in the produced water.

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:

TABLE VIII-4
SUMMARY POLLUTANT CONCENTRATIONS FOR SETTLING EFFLUENT FROM THE 1992 EPA 10 PRODUCTION FACILITY STUDY[5]

Pollutant	Settling Effluent Concentration (ug/l)	Pollutant	Settling Effluent Concentration (ug/l)
CONVENTIONAL AND NON-CONVENTIONAL POLLUTANTS		Trichlorofluoromethane	294.00
Total Recoverable Oil and Grease	52,956.00	**OTHER VOLATILE ORGANICS**	
Total Suspended Solids	133,063.00	Carbon Disulfide	8.48
Ammonia	65,773.00	Chloromethane	28.60
Chlorides	65,111,000.00	m-Xylene	136.00
Total Dissolved Solids	84,036,000.00	o+p Xylene	86.10
Total Phenols	2,030.00	Vinyl Acetate	29.40
PRIORITY POLLUTANT METALS		2-Butanone	122.00
Antimony	166.00	2-Hexanone	35.80
Arsenic	10.80	2-Propanone	913.00
Beryllium	5.56	**PRIORITY POLLUTANT SEMI-VOLATILE ORGANICS**	
Cadmium	22.80	Bis(2-ethylhexl)phthalate	46.00
Chromium	128.00	di-n-Butyl Phthalate	46.00
Copper	180.00	Naphthalene	144.00
Lead	515.00	Phenol	553.00
Mercury	0.58	**OTHER SEMI-VOLATILE ORGANICS**	
Nickel	109.00	Benzoic Acid	3,813.00
Selenium	250.00	Benzyl Alcohol	49.50
Silver	252.00	Hexanoic Acid	790.00
Thallium	180.00	n-Decane	139.00
Zinc	329.00	n-Docosane	38.00
OTHER METALS		n-Dodecane	225.00
Aluminum	1,072.00	n-Eicosane	68.00
Barium	52,573.00	n-Hexosane	36.10
Boron	20,244.00	n-Hexadecane	283.00
Calcium	2,501,000.00	n-Octacosane	35.20
Cobalt	83.60	n-Octadecane	82.90
Iron	15,492.00	n-Tetracosane	38.20
Magnesium	615,699.00	n-Tetradecane	119.00
Manganese	1,301.00	n-Triacontane	35.00
Molybdenum	86.90	o-Cresol	121.00
Strontium	205,500.00	p-Cresol	149.00
Sulfur	9,683.00	1,2:3,4-Diepoxybutane	71.10
Tin	305.00	2-Methylnaphthalene	67.20
Titanium	32.40	2,4-Dimethylphenol	117.00
Vanadium	96.60	**RADIONUCLIDES**	
Yttrium	25.00	Gross alpha (pCi/l)	383.54
PRIORITY POLLUTANT VOLATILE ORGANICS		Gross beta (pCi/l)	312.63
Benzene	4,285.00	Lead 210 (pCi/l)	64.28
Ethylbenzene	115.00	Radium 226 (pCi/l)	172.18
Methylene chloride	170.00	Radium 228 (pCi/l)	228.40
Toluene	3,370.00		

TABLE VIII-5
PRODUCED WATER POLLUTANT CHARACTERIZATION FOR COOK INLET, ALASKA

Pollutant Parameter	Concentration (ug/L)
CONVENTIONALS	
Oil & Grease (mg/L)	35.4[a]
TSS (mg/L)	67.5[b]
PRIORITY METALS	
Arsenic	114.19[b]
Cadmium	22.62[b]
Copper	444.66[b]
Lead	195.09[b]
Nickel	1705.46[b]
Zinc	44.77[a]
PRIORITY ORGANICS	
2,4-Dimethyl phenol	514.70[a]
Anthracene	25.25[a]
Benzene	3386.12[a]
Benzo(a)pyrene	10.56[a]
Chlorobenzene	8.05[a]
Di-n-butylphthalate	16.08[b]
Ethyl benzene	157.73[a]
Naphthalene	933.54[a]
Phenol	431.49[a]
Toluene	1507.43[a]
NON-CONVENTIONALS	
n-Alkanes	1641.5[b]
p-Chloro-m-cresol	25.24[b]
Steranes	77.5[b]
Triterpanes	78[b]
2-Butanone	1028.96[b]
Total Xylenes	542.47[a]
Aluminum	78.01[b]
Barium	55563.80[b]
Boron	25740.25[b]
Iron	4915.87[b]
Manganese	115.87[b]
Titanium	7.00[b]
Radium 226	0.00000265[c]
Radium 228	0.00000750[c]

a: Source - Envirosphere, 1989
b: Source - EPA, January 1993[2]
c: Source - AOGA, 1991; The values shown were converted from pCi/l to ug/l using the conversion of 1 gm = 1 curie. The original values were 1.39 pCi/l for Radium 226 and 3.12 pCi/l for Radium 228.

- Equalization (surge tank, skimmer tank)
- Chemical addition (feed pumps)
- Oil and/or solids removal
- Gravity separators
- Flotation
- Filters
- Plate coalescers
- Filtration (used prior to subsurface disposal)
- Subsurface disposal (injection).

The amount of 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. The removal efficiency and resultant effluent quality achieved by the treatment unit is also 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 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 coastal 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 space, waste characteristics, volumes, existing discharge limitations, and other site specific factors. Oil skimming with gravity separation and/or chemical treatment using settling tanks is widely used in the coastal industry because the support structure is relatively inexpensive (compared to offshore platforms where more compact technologies are installed) and maintenance costs are low compared to more sophisticated technologies. 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 coastal 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 IX.

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 and produced water, flow rates, and retention time. Gravity separation systems

with large residence times are typical for coastal operations, however on the Cook Inlet platforms that do not pipe produced water to onshore facilities, gravity separation systems have limited residence times 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. Many coastal operations configure two or more gravity separators in series with the first separator acting as both an equalization tank and as a gravity separator.

Offshore type platforms such as those in Cook Inlet, Alaska use a devise called a skim pile as the final gravity separation treatment step. 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 VIII-1 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.

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.

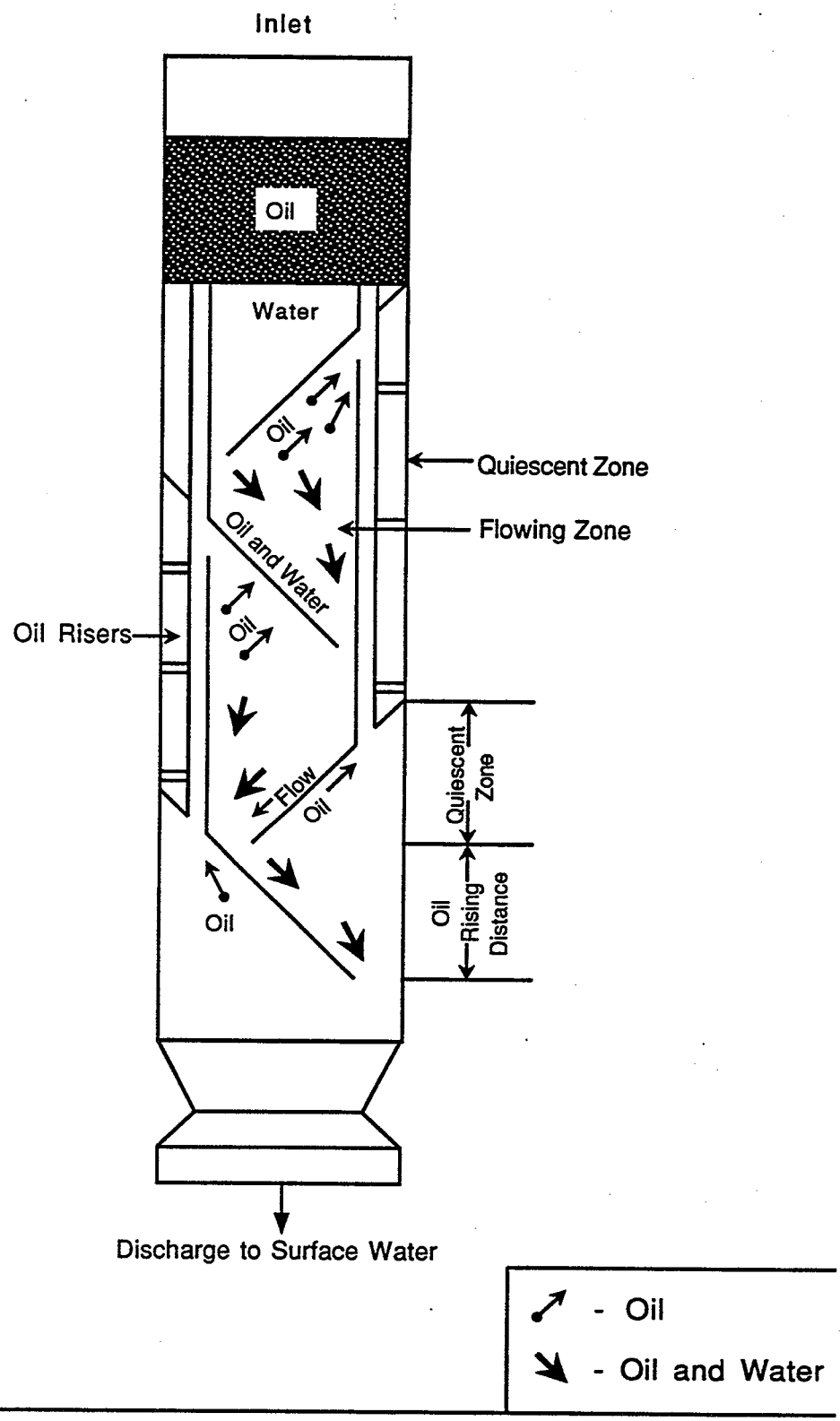

Figure VIII-1
Typical Skim Pile

5.1.5 Gas Flotation

Although gas flotation may be used for BPT treatment (and served as the technology basis for BPT limitations established in 1979), it is currently used at only a small proportion of coastal facilities in the Gulf of Mexico. Results of the 1993 Coastal Oil and Gas Questionnaire show that the majority of coastal operators are using gravity separation instead of gas flotation to comply with current BPT limitations. The questionnaire results showed that only 20 facilities out of the 224 that were surveyed in the coastal Gulf of Mexico area reported using gas flotation.[1] However, improved gas flotation is being considered as a BAT technology for the coastal subcategory and is discussed as such in Section 5.2.1.

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. Gas flotation may also aid in the removal of oil-wet solids, finely divided solids and solids with low specific gravity. These solids become entrained in, and exit the system with the oily 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 in offshore operations.[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. However, space requirements at coastal facilities are not as limited and therefore coastal operators may elect to install DGF.

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. Often the oil and solid particles act as nuclei for the growing gas bubbles. 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 pressurized 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 pressurized saturated water passes through a backpressure regulator before entering the flotation unit. This regulator facilitates the necessary instant pressure drop in the system and creates turbulence for proper dispersion of super saturated water. 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. The more dense suspended material which is not amenable 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 oil particles and floats them to the surface. A skimmer system is used to remove the floated oil and 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 of IGF 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.[9,11,12]

Figure VIII-2 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.

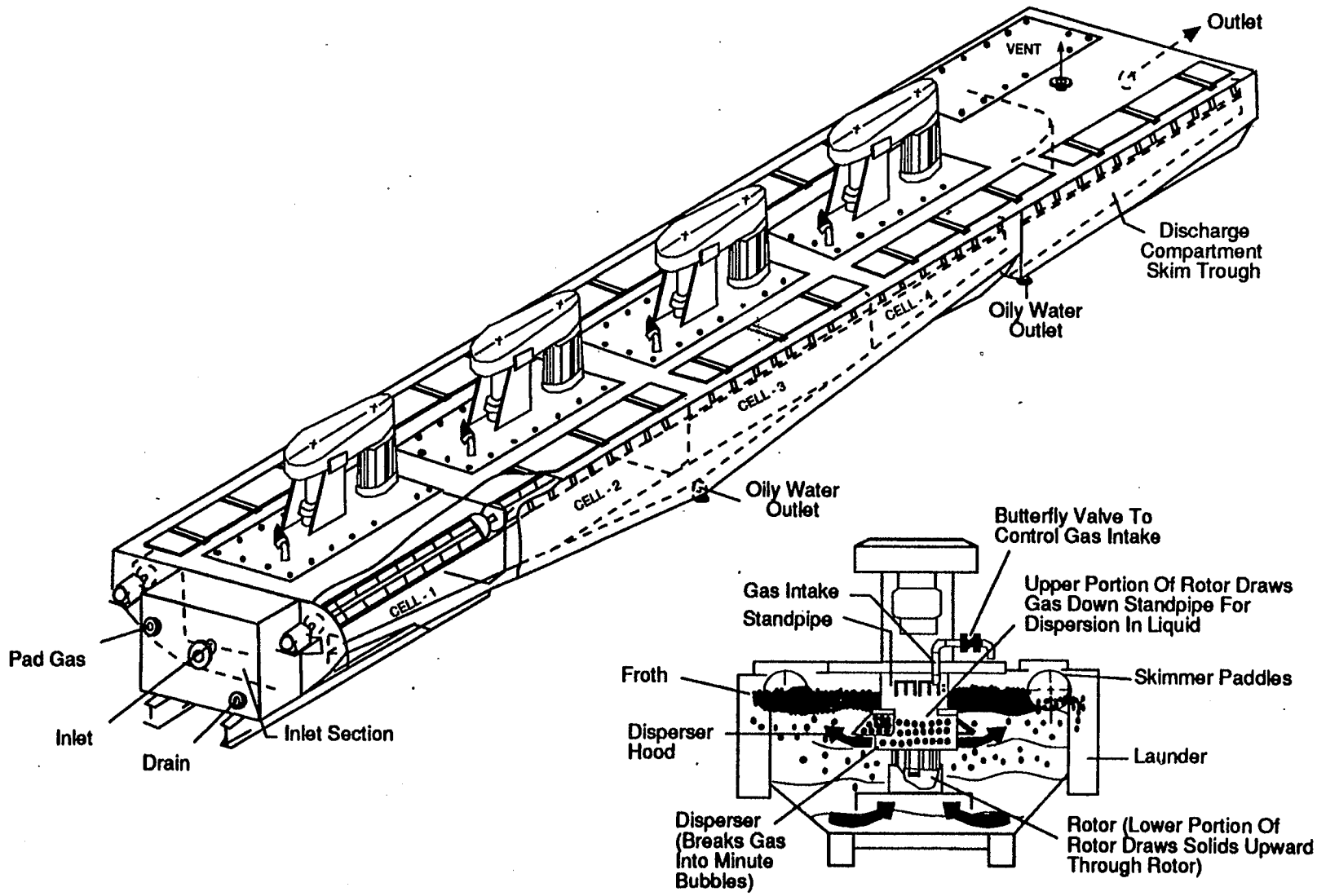

Figure VIII-2
Dispersed Gas Floatation Unit

Source: Paragon Engineering Services

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]

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 gravity separation systems, plate coalescers, and flotation units. The three basic types of chemicals that are used to enhance equipment removal efficiencies in wastewater treatment are:

Surfactants: 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 are sometimes used to treat oil-wet solids. Oil-wet solids tend to settle poorly because the combined lower density of the oil and higher density of the solids results in particles that have neutral buoyancy in water. Surfactants break apart the oil and solids so that they can more readily separate from the water.

Coagulants: 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.

Polyelectrolytes: 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 usually injected into the wastewater in the piping 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 Subsurface Injection and Filtration

Subsurface disposal is sometimes used to comply with BPT limits. Injection is generally used for waterflooding to enhance production (or to meet water standards). At some facilities injection is preceded by a filtration process to protect the formation face from becoming fouled with solids.

Subsurface injection and filtration are identified as BAT technologies as a means of disposing of produced water and therefore are 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 injection, cartridge filtration, 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

During the development of the offshore rule, EPA evaluated the costs and feasibility of improved performance of gas flotation treatment systems to determine whether more stringent effluent limitations based on improved performance of gas flotation would be appropriate. Since most coastal facilities do not currently use this technology it is reasonable to assume that for most coastal the improvements can be designed into any newly installed systems. The performance data for this technology has been adopted from the offshore rule. Table VIII-6 presents summary data for improved gas flotation effluent as compared to settling effluent.

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]

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. Three basic types of chemicals, which are

TABLE VIII-6
PRODUCED WATER EFFLUENT CONCENTRATIONS
GULF OF MEXICO

Pollutant Parameter	Settling Effluent[5]	Improved Gas Flotation Effluent[a]
	Concentrations (mg/l)	
Oil & Grease	52.956	23.5
TSS	133.063	30.0
	Concentrations (μg/l)	
1. Priority Organic Pollutants		
Bis (2-ethylhexyl)phthalate	46.00	46.00[b]
2,4-Dimethylphenol	117.00	117.00[b]
Benzene	4,285.00	1,225.91
Chloromethane	28.60	28.60
Di-n-butylphthalate	46.00	6.43
Ethylbenzene	115.00	62.18
Methylene chloride	170.00	170.00[b]
Naphthalene	144.00	92.02
Phenol	553.00	536.00
Toluene	3,370.00	827.80
2. Priority Metal Pollutants		
Antimony	166.00	166.00
Arsenic	10.80	10.80
Beryllium	5.56	5.56
Cadmium	22.80	14.47
Chromium	128.00	128.00
Copper	180.00	180.00
Lead	515.00	124.86
Nickel	109.00	109.00
Selenium	250.00	250.00
Silver	252.00	252.00
Thallium	180.00	180.00
Zinc	329.00	133.85
3. Other Non-Conventional Pollutants		
Acetone	913.00	913.00[b]
Aluminum	1,072.00	49.93
Ammonia	65,773.00	65,733.00[b]
Barium	52,573.00	35,560.83
Benzoic acid	3,813.00	3,813.00[b]
Benzyl alcohol	49.50	49.50[b]
Boron	20,244.00	16,473.76
2-Butanone	122.00	122.00[b]
Calcium	2,501,000.00	2,501,000.00
Carbon disulfide	8.48	8.48[b]
Chlorides	65,111,000.00	65,111,000.00
Cobolt	790.00	790.00[b]
1,2,3,4-Diepoxybutane	71.10	71.10[b]
Hexanoic Acid	83.60	83.60
2-Hexanone	35.81	35.81[b]
Iron	15,492.00	3,146.15
Magnesium	615,699.00	615,699.00
Manganese	1,301.00	74.16
2-Methylnapthalene	67.20	67.20[b]
Molybdenum	86.90	86.90
n-Decane	139.00	139.00[b]
n-Docosane	38.00	38.00[b]
n-Dodecane	225.00	225.00[b]
n-Eicosane	68.00	68.00[b]
n-Hexosane	36.10	36.10[b]
n-Hexadecane	283.00	283.00[b]
n-Octacosane	35.20	35.20[b]
n-Octadecane	82.90	82.90[b]
n-Tetracosane	38.20	38.20[b]
n-Tetradecane	119.00	119.00[b]
n-Tricontane	35.00	35.00[b]
o-Cresol	121.00	121.00[b]
p-Cresol	149.00	149.00[b]
Strontium	205,500.00	205,500.00
Sulfur	9,683.00	9,683.00
Tin	305.00	305.00
Titanium	32.40	4.48
Trichlorofluoromethane	294.00	294.00[b]
Total Xylenes	222.10	222.10[b]
Vanadium	96.60	96.60
Vinyl acetate	29.40	29.40[b]
Yttrium	25.00	25.00

Sources:
a) Concentrations in this column are from the Offshore Development Document[2] unless otherwise noted.
b) For the purpose of regulatory analysis, these concentrations are substituted using the settling effluent concentrations[5] either because no data were available in the Offshore Development Document or because the offshore gas flotation value was greater than the settling effluent value.

previously discussed in Section 5.1.6, are generally utilized to improve the efficiency of the gas flotation units used for treatment of produced water; these chemicals are surface active agents, coagulating agents, and polyelectrolytes. Inorganic chemicals, such as the aluminum or ferric salts and activated silica, can be used as coagulating agents to bind the particulate matter and to create a structure that can easily entrap air bubbles. Various surface active 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.

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.

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]

For those few coastal facilities that already have gas flotation in place most modifications to improve gas flotation 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 Subsurface Injection

Disposal of produced water by injection 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 (waterflooding).

- Stabilize (support) geologic formations which settle during oil and gas extraction (a significant problem for older, i.e onshore and coastal, more depleted reserves).

Coastal and onshore produced water injection is a well-established practice for disposal of produced water.

As part of the offshore rulemaking process, and in response to industry concerns about the feasibility of injection due to the receiving formation characteristics, EPA evaluated the technical feasibility of implementing this technology at both existing and new offshore facilities.[22] The study showed that injection is generally technologically feasible in all offshore areas, i.e., suitable formations and conditions are available for disposal operations. The same is generally true for the coastal regions in that the geologies of the North Slope and the Gulf Coast consist of formations which can readily accept injected produced water. Other locations may experience problems in being able to inject due to site-specific formation characteristics or proximity to seismically active areas.

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

5.2.2.1 Industrial Practices by Location

Most of the produced water generated in the coastal and offshore areas of California is presently injected for waterflooding to enable recovery of the heavy crude oil that is typically produced in that part of the country. In the Gulf of Mexico, produced water generated in the coastal region is either treated to the BPT limitations and discharged to the surface waters or it is injected for disposal. Coastal injection experiences in Texas and Louisiana have shown that the characteristics of the regional geology make it possible to inject produced water at most locations in the adjacent coastal region. However, in Cook Inlet, there are no formations onshore directly beneath the treatment facilities to accept the large volumes of produced waters treated, making injection onsite unfeasible[27].

The data in Table IV-1 show that EPA estimates that there were 853 production facilities in Texas and Louisiana in 1992 and of those, 325 were discharging produced water to surface waters. The Coastal Oil and Gas Questionnaire Summary Statistics showed that of the production facilities in the Gulf of Mexico that dispose of produced water by injection or surface discharge, an estimated 61 percent were injecting produced water in 1992.[1] Thus, it can be assumed that the majority of the estimated 528 production facilities not discharging in 1992 were disposing of produced water by subsurface injection.

As shown in Table IV-1, EPA estimates that the number of coastal facilities discharging produced water in the Gulf region will drop to 216 by 1996 due to State of Louisiana requirements to cease discharging of produced water based on water quality standards.

All of the coastal operations in the North Slope region of Alaska inject all of their produced water primarily for waterflooding. In Cook Inlet, Alaska, produced water is surface discharged after BPT treatment. However, waterflooding is being performed using seawater.

5.2.2.2 Well Selection and Availability

There are a number of considerations in the planning, design, and operation of a produced water injection system. 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.

5.2.2.2.1 Formation Characteristics

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 injection 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 higher

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 injected 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 injection exceeds fluid withdrawals. Pressure-depleted aquifers of older producing reservoirs are highly desirable as disposal formations, provided the disposal practice will not adversely affect the producing reservoir.

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.[23] Abandoned producing formations are ideal for disposal because the original fluids were trapped in the formation. Fluids injected into those formations also will be trapped and will not migrate into other areas.

5.2.2.2.2 Possible Environmental 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.

Another possible concern is improperly plugged and abandoned wells located near the disposal well. This is particularly true for older fields such as those in the Gulf of Mexico coastal region. Improperly plugged and abandoned wells that penetrate the disposal formation within the range of influence of the disposal well can serve as conduits for migration of the disposed or displaced fluid into drinking water aquifers or into producing formations where it may damage the formation. To prevent this occurrence, most states require as part of the injection well permit application that the operator conduct an area of review (AOR) investigation to locate any improperly plugged and abandoned wells within a certain radius of the proposed injection well. In the state of Texas, this radius is 0.25 miles unless otherwise specified by the permitting authority. Conducting an AOR, at a minimum, involves the search of public records for suspect wells. Any improperly plugged and abandoned well that is located within the specified area must be properly plugged prior to the approval of the injection well permit. At the time of this writing, EPA's Federal Underground Injection Control Program is involved in proposing additional AOR requirements.

5.2.2.2.3 New Versus Converted Wells

Whether the objective is enhanced ("secondary") recovery or disposal, a primary requirement for the proper design of a injection well is that the produced water be delivered to the receiving formation without leaking or contaminating fresh water or other mineral bearing formations. The injection 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 injection from platforms supported on pilings, adequate equipment and storage space must be provided at the facilities.

The drilling of a new injection well is very similar in practice to the drilling of production wells except that injection wells may not need to be drilled as deep as the production wells they serve, if shallower disposal formations are available. The advantages of drilling a new well specifically for produced water injection include the following:

- Location can be selected to minimize surface piping.
- Location can be selected to utilize optimal geologic formations.
- Casing and long string can be sized to handle designed produced water flowrates.
- Casing can be properly cemented to meet regulatory requirements.
- Desired casing grades and weights may be used.

The disadvantages of drilling new injection wells are:

- Costs are higher than converting an existing well.
- Geology and downhole conditions may not be known prior to drilling.

Figure VIII-3 presents a schematic of a typical well drilled for subsurface injection. EPAs' field investigations found that the conversion of existing production wells to injection wells is the most common practice in the coastal Gulf of Mexico region primarily due to availability and costs. Conversions are most commonly performed on depleted production wells using wells whose hydrocarbon production rates have or soon will diminish to the point where they are no longer economical to operate as production wells (i.e. depleted wells). Wells that were never completed (dry holes) and old plugged and abandoned wells may also be used, but may require more work at greater expense.[24]

The most common method of conversion involves recompletion of the well at a shallower depth into a non-hydrocarbon producing formation. In such a case the lower portion of the well is cemented.

5.2.2.2.4 Regional Geological Considerations

California

There is little question about the technical feasibility of injecting produced water at the existing facilities in the coastal region of California because the current practice of this technology is common. In the coastal and offshore subcategories for California, all of the produced water is injected for the sole purpose of enhanced recovery by waterflooding. In fact, at the THUMS facilities in Long Beach Harbor, additional brine to that of the produced water must be injected to provide sufficient pressure maintenance. Injection of produced water is not practiced in areas where there is potential for seismic activity.[40] The coastal geological conditions and engineering requirements for the injection 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

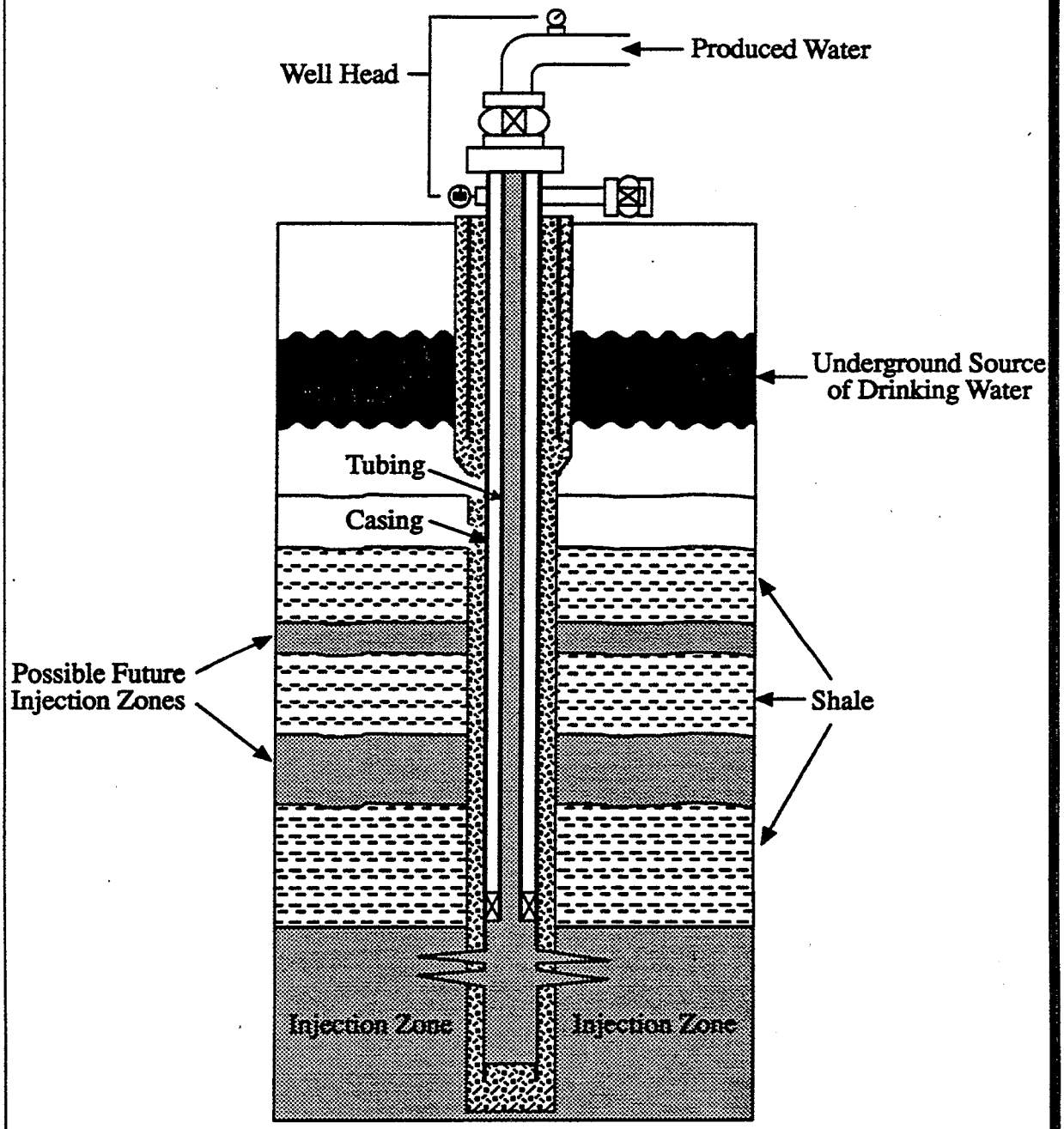

Figure VIII-3
Typical Subsurface Injection Well

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 injection wells, availability of coastal 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 injection of brines from existing sources.

Gulf of Mexico

In the Gulf of Mexico, injection of brines from existing coastal sources is common (see Section 5.2.2.1). The two most common disposal practices are either to pretreat and inject or to treat the brines to the BPT effluent limitations and discharge. Waterflood projects are no longer common in the Gulf of Mexico; it is estimated that less than ten facilities in the Gulf of Mexico inject produced water for pressure maintenance.[25] The primary reason that waterflooding is not common is because, unlike California, extraction of the formation fluids from the reservoirs in the Gulf of Mexico does not necessarily require the additional water drive provided by waterflooding. Secondly, economics prevent secondary recovery operations in the Gulf of Mexico. Additionally, older fields benefit less over time from this practice. The additional oil recovered due to waterflood is not worth the cost of the injection 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.

Injection of brines for disposal from existing and new sources in the coastal Gulf of Mexico region depends on the availability of an adequate number of suitable disposal formations. In the early stages of production, there is little need for injection fluids to enhance recovery and, therefore, the produced water would be injected only for disposal purposes. The coastal injection experience in Texas and Louisiana has shown that injection of produced water is possible where there are suitable disposable formations available. Throughout most of the coastal region of Louisiana and Texas, the oil and gas producing formations are overlaid with alternating sequences of sand and shale sediments formed by ancient rivers and oceans and make up a considerable part of the stratigraphic column.[22] The advantages of using these formations for disposal include:

- Formation thicknesses, depths, porosities and permeabilities are usually available from logs of the production wells and past experience.
- Shallower depths require less drilling and tubing, thereby reducing construction and future remedial well work costs.

- Production wells can be converted to disposal wells without affecting producing reservoir dynamics.

Eight of the nine non-commercial coastal injection facilities in the Gulf of Mexico region investigated by EPA in 1992 were disposing of produced water into sand formations shallower than the producing formations.[26] Several facilities indicated that additional shallower sand formations existed that could be used in the future by recompleting the disposal wells at a shallower depth. The only disadvantage of using shallower formations is that the maximum allowable injection pressure will be reduced. This can result in lower injection pressures and more frequent remedial well work.

Alaska

In the North Slope region of Alaska, all produced water generated is injected with the major portion being used for waterflooding. Waterflooding is also practiced in Cook Inlet, however, seawater is used rather than the produced water. The water flooding occurring in Cook Inlet has reached "parity" which means that the volume of seawater injected is essentially equal to the combined volume of oil and produced water that is brought to the surface. Therefore, it is conceivable that the seawater could be replaced with produced water with the difference (equal to the volume of oil extracted) being made up with seawater.

A study of the technological feasibility and the economic analysis of subsurface disposal in Cook Inlet was performed for produced water from the Trading Bay.[27] In this report, three injection alternatives were considered and evaluated: 1) treatment and injection for waterflooding at the platform; 2) piping produced water to an onshore facility for treatment and return to the platform for injection for waterflooding; and 3) piping produced water to an onshore facility for treatment and injection for disposal. In this study, alternatives 1 and 2 were reported to be technically feasible, however, several operational problems were identified that could affect the system. These problems, along with preventative remedial measures are discussed below.

For the third alternative, the study suggests that the available Tyonek sands injection formations directly beneath the Trading Bay Facility (which discharges 94% of the Cook Inlet produced waters) are not suitable to accept the large amounts of produced water generated at this facility. Although significant in gross pore volume, these formations are broken up into numerous smaller reservoirs. Continuous injection into any one reservoir could cause the reservoir to become overpressurized, threatening to cause fracturing and migration to shallower potable water aquifers and possibly triggering seismic activity. In

addition, the Tyonek formations contain significant amounts of water-sensitive clays which, when injected with the relatively fresh produced water from the Trading Bay Facility, could result in severely or completely restricted permeability.[27]

5.2.2.3 Technical Problems

Some of the technical problems that may be associated with subsurface injection of produced water are described below. In general, these potential problems can be avoided or remedied through engineering and operational applications such as the use of treatment chemicals. Possible solutions for each of the problems are also discussed.

Formation Plugging and Scaling - Scales and sludges that are commonly found in produced water disposal systems include: calcium carbonate, magnesium carbonate, calcium sulfate, barium sulfate, strontium sulfate, iron sulfide, iron oxide, and sulfur. These scales and sludges can form in collection and distribution lines, treating equipment, well tubulars and at the injection formation.[28]

Scale and sludge differ in that scale is a deposit formed in place on surfaces in contact with water, while sludge may be formed in one place and deposited in another. Sludges may collect in low flow rate areas of a system such as tanks and vessels, in the bends of lines and on filter surfaces.[28]

Scales and sludges are formed from water as the waters adjust to changes in equilibrium. Changes in equilibrium are caused by temperature changes, pressure changes, chemical changes, and the mixing of two or more stable but incompatible waters. Scale may form as a result of a chemical reaction between the water, or some impurity in the water, and the pipe. Corrosion products, such as iron oxide or iron sulfide, may be scales of this type. Other precipitates, such as sulfur, may form when water with hydrogen sulfide is mixed with water with a high dissolved oxygen content.[28]

The solubility of calcium carbonate (a common component of groundwater) is influenced by the concentration of dissolved carbon dioxide in water. If calcium carbonate is present in an underground formation and the concentration of dissolved carbon dioxide in the formation water is increased, the amount of dissolved calcium carbonate will increase. When the dissolved carbon dioxide concentration is reduced, such as when carbon dioxide-rich produced water comes to the surface where the pressure is lower and it comes into contact with air, the reverse occurs, and the carbon dioxide is released and

calcium carbonate will precipitate.[29] Also, the solubility of most scales decreases with decreasing temperatures.

All of the produced water operations in the 1992 EPA 10 Production Facility Study sampling effort maintained closed systems that exclude air using gas blankets. When the produced water samples were cooled and exposed to air, a noticeable increase in turbidity and a color change occurred for most samples. The turbidity was probably the result of calcium carbonate precipitation and the color change was probably the result of the oxidation of dissolved iron.

Scale Prevention - Scale formation is normally preventable. Once formed, however, scale removal is expensive and may cause some permanent damage. Individual waters or mixtures of waters should be tested prior to the design of the produced water disposal system to determine if scale deposition will be a problem. The waters that are to be added to an existing system should also be tested prior to hookup.[28]

Scale deposition of waters can be predicted with moderate accuracy using conventional water analysis and the Stiff-Davis method of predicting the approximate solubility of calcium carbonate and calcium sulfate in produced waters. Compatibility tests will also indicate if scale formation is to be expected.[28]

Depending on the type of scale involved, methods of preventing or removing scale prior to injection include: maintaining a closed system using gas blankets; use of scale inhibiting chemicals; use of acid treatment; use of settling tanks with chemical addition; filtration; and prevention of mixing incompatible waters.

In Cook Inlet, Alaska, the operators have expressed concern that the produced water contains a significant amount of scale-forming ions, primarily calcium carbonate, and that the use of treated produced water for waterflooding will result in the rapid plugging of the injection wells. One problem associated with this is that the onshore produced water treatment systems at Trading Bay, Granite Point and East Forelands do not maintain closed systems with gas blankets throughout the system. Therefore, there is a greater potential for produced water from these systems to develop calcium carbonate scale. However, the use of the remedies discussed above such as gas blankets and chemical treatment should substantially alleviate this problem.

In addition to scales and sludges, production formation solids such as sands are commonly found in produced water disposal systems. This is especially true for produced waters from unconsolidated sand formations which are common in the Gulf Coast region. Formation solids referred to as produced sand in this report are most commonly removed using settling tanks and filters in the coastal areas of the Gulf of Mexico.

Formation Swelling - The injection of water with a lower total dissolved solids or salt content than the injection formation water can cause clay particles embedded in the formation to swell. However, this is generally not a problem for produced water injection in the Gulf Coast region because produced water in the Gulf Coast region generally has a total dissolved solids or salt content which is several times that of seawater. This swelling in turn increases the necessary injection pressure and may decrease the injection capacity of the injection well. This phenomenon was reported by the Campbell Wells facility at Bourg, Louisiana which injected a high proportion of relatively fresh washwater (about 73 percent) from their land treatment operation along with produced water from commercial clients (about 27 percent).[30] The result was that higher injection pressures were necessary but injection was not prevented. In Cook Inlet, the use of seawater for waterflooding does not appear to have created a swelling problem. This problem can also occur at facilities that combine a significant quantity of contaminated stormwater with produced water for disposal.

Corrosion - A more common problem encountered in combining fresh water, such as stormwater, with produced water for injection is corrosion caused by dissolved oxygen. The corrosion of metals in a produced water disposal system is usually caused by electrochemical reactions. In this type of reaction an anode (electron donor) and cathode (electron acceptor) must exist in the presence of an electrolyte (ionic solution) and an external circuit. Anodes and cathodes can exist at different points on the steel surfaces with the steel providing the external circuit. A brine solution provides an excellent electrolyte. Thus, an electric circuit can be set up in the unprotected, produced water-handling pipelines with iron being oxidized at one portion of the system (cathode) and iron being reduced and corroded away in another portion (anode).

Corrosion damage can occur uniformly as a gradual thinning of the anode portion, or it can occur in the form of pitting where localized electrolytic cells are set up. It can also occur as galvanic corrosion when two different metals come into contact and form an electrolytic cell.

Dissolved oxygen is a major producer of corrosion. Oxygen-induced corrosion is the result of an electrochemical reaction between a metal, such as iron, and the oxygen where the oxygen accepts electrons and the metal donates electrons. While oxygen is normally absent in formation waters, it is unavoidably absorbed by contact with air in open produced liquid handling systems and can also be introduced with the addition of contaminated stormwater.

Corrosion Prevention - At three of the ten production facilities that EPA sampled, contaminated stormwater was periodically added to the produced water for treatment and disposal.[26] The dissolved oxygen in the stormwater can be removed using a chemical (oxygen scavenger) which combines with the oxygen. In addition, the use of closed systems with gas blankets can prevent the introduction of oxygen to the system.

Incompatibility of Injected Produced Waters with Receiving Formation Fluids - In the design and operation of a produced water injection system, the compatibility of injected produced waters with the fluids already in the receiving formation is an important consideration. Incompatibility occurs when one or more of the chemicals in the produced water reacts with chemicals in the existing reservoir fluid to cause an undesirable effect, such as precipitation of scale. This condition could also occur if incompatible waters from different reservoirs or surface sources are to be mixed prior to injection. Precipitation damage resulting from incompatible fluids is usually in the form of plugged pore spaces in the injection zone. Precipitates that may be associated with incompatible fluids include calcium carbonate, magnesium carbonate, calcium sulfate, barium sulfate, and strontium sulfate. Both barium sulfate and strontium sulfate are highly insoluble in water and are extremely difficult to remove.

Incompatibility Prevention - Treating produced water to prevent incompatibility consists of reducing the strength of or removing the reactive element or otherwise altering the nature of the injected fluid using treatment chemicals.

Bacteria - The presence of bacteria in a system may present a corrosion or plugging problem. Bacteria in oil field waters may be aerobic (active in presence of oxygen), or anaerobic (active in the absence of oxygen).

Iron bacteria are aerobic and are active in removing iron from water and depositing it in the form of hydrated ferric hydroxide. They are commonly active in fresh waters but are occasionally found in produced waters containing oxygen. The removal of oxygen by the bacteria causes an anaerobic

condition to exist under the ferric hydroxide iron deposits on vessel walls where sulfate reducing bacteria can grow and corrode the vessel walls. Both types of bacteria are easily controlled with bactericides.[28]

Aerobic bacteria, or slime formers, can grow in sufficient numbers to cause significant well plugging. Aerobes are indicators of excessive bacterial activity in oxygen-bearing waters and if present in a closed system indicate that air contamination exists. The slimes that are formed shield the metal surfaces from oxygen and provide an environment for the growth of sulfate reducing bacteria. Control of aerobic bacteria is generally accomplished by treatment with an organic biocide.[28]

Anaerobes are active in the absence of oxygen but are not killed by the presence of oxygen. Anaerobes, except sulfate reducers, multiply slowly and normally are found under slime deposits. They are effectively killed with bactericides. Although chlorine could be used, in a closed system chlorine is not used because it is an oxidizing agent.[28]

Sulfate reducing bacteria are the most common and economically significant of the bacteria found in salt water disposal and injection systems. Sulfate bacteria are economically significant due to the corrosion problems associated with them. Sulfate reducing bacteria are anaerobic and have the ability to convert sulfate to sulfide. Sulfate reducers are most active in neutral to mildly acidic waters, are frequently found under slime deposits, and are most prolific under corrosion products, tank bottoms, filters, oil water interfaces, and dead water areas, such as joints, crevices, and cracks in cement linings. Sulfate reducers may also exist naturally in some oil and water producing strata.[28]

In addition to being corrosive, hydrogen sulfide is highly toxic and can cause embrittlement of steel. Hydrogen sulfide is sometimes present in significant quantities in the hydrocarbon producing formations where it was created in the past by sulfate reducing bacteria that were present in the formation. When brought to the surface, it separates out with the gas phase. This type of natural gas is referred to as "sour gas" and is a potential health problem for operators. Thus, its presence requires safety training of operators and the use of special safety equipment and preventive measures. In addition, the corrosion and embrittlement problem may require the use of special steel alloys or coatings in the production equipment. The sour gas must be treated to remove hydrogen sulfide prior to delivery to the pipeline.[31]

The operators at Cook Inlet have expressed concern that the replacement of seawater with treated produced water for use in waterflooding will result in the growth of sulfate reducing bacteria.[27] They

say that the result will be that the bacteria will plug the formation and will generate hydrogen sulfide which will return to the surface with the produced fluids creating corrosion and safety hazards. The reason that this does not currently occur is that the seawater does not contain the nutrients necessary to promote bacterial growth. However, they claim that the standard treatment chemicals used in processing the produced water contains nutrients that will promote bacterial growth and that the previous use of seawater for waterflooding has introduced a substantial quantity of sulfate to the formations.

Bacteria Prevention - As noted above, the prevention of bacterial growth is primarily remedied with the use of bactericides which are injected into the produced water treatment system influent. In addition, if process treatment chemicals are the source of nutrients that are conducive to bacterial growth, the substitution of these chemicals with ones that do not contain the nutrients can be an effective preventive measure.[32]

Injection Into Producing Formations - Injection into producing formations is not extensively practiced in the coastal region of the Gulf of Mexico because of potential problems that waterflooding can cause by adversely changing the field pressure.[22] These pressure changes can cause a production loss from nearby production wells either by coning at the injection wellbore or, if there is directional permeability within the reservoir, the rapid return of injected water back to the production wellbore. Increased pressure can also cause movement of the formation fluid containing the oil and gas away from the production 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 injection into a producing formation.

5.2.2.4 Down-Hole Remedial Measures

During the life of an injection system, formation capacity may decrease significantly due to formation plugging (from suspended solids, precipitation, hydrocarbons, or bacteria) or fouling of flowlines from scale or biological growth. Should these problems develop, the following remedial measures have been used to increase and prolong capacity.[28]

Acidizing - In many cases the receptivity of a formation may be improved or restored by acid treatments. In carbonate formations, acid will dissolve or etch fluid passageways through the treated area of the formation, creating an enlarged effective well bore. In all formations, foreign materials introduced while drilling, completing, or injecting into a well may block or plug the formation. Acid cleanup

treatments may dissolve, loosen, shrink, or affect these foreign materials so that they may be removed by swabbing, or dispersed by flushing. A well should never be left shut-in following acid treatments. The spent acid and residual products should be removed from the well bore immediately after the reaction time of the acid.[28]

Only one of the 10 injection production facilities in the 1992 EPA coastal sampling effort reported performing an acid treatment and reported that the well injectivity improved for only a short period of time. One of the commercial facilities in the 1992 EPA coastal sampling effort reported that they routinely added acid to their first equalization tank prior to injection. This was most likely done to reduce the quantity of scales and sludges present in the incoming water shipments as well as those that may form as a result of the mixing of water from different sources. Scales and sludges that are effectively treated with acid include calcium carbonate, magnesium carbonate, iron oxide, and iron sulfide.[28]

Sand Jetting or Under Reaming - An injection well completed in open hole (without casing) may cease to take water because of damage or plugging at the formation face. The formation can be reconditioned by removing the face of the formation with a high velocity jet of sand-laden fluid, or by cutting away the face of the formation using an underreamer. In cases of insoluble scale damage, these methods could be more effective than acid treating.[28] None of the nine non-commercial or two commercial injection facilities in the 1992 EPA Coastal sampling effort reported performing a sand jetting or underreaming operation on an injection well.[33]

Backwashing - Periodically, wells can be backflowed to clean the formation face. Backwashing is performed by sparging gas, usually nitrogen, near the bottom of the injection tubing which creates an upward flow of injection/formation fluid and solids that are plugging the formation face. This operation is similar in principal to backwashing a filter. The fluids and solids are captured in tanks and are hauled offsite for treatment and disposal. In some cases the fluids and solids are treated onsite, and the treated fluids are injected. Special strings of tubing are used to facilitate this operation. One practice that is becoming increasingly more common is the use of coil tubing. Coil tubing refers to a long flexible metal tube that is stored on a large spool. The tube is inserted down the well production tubing to perform the backwash. The method is replacing the old method of using rigid threaded pipe sections which takes more time and manpower to utilize. This operation was the most commonly cited remedial measure conducted by the facilities in the 1992 EPA Coastal sampling effort.[33]

Treating with Solvents, Dispersants, and Other Chemicals - In special cases where injection wells have suffered loss of receptivity from known or identifiable causes, chemical treatments for the specific cause may be appropriate. Treatments of this type include solvents to remove asphaltines or paraffins, converter type treatments for the relatively acid-insoluble scales such as calcium sulfate or barium sulfate, fresh water for the removal of salt blocks, and emulsion breakers for an emulsion problem.[28]

5.2.2.5 Pretreatment of Produced Water Prior to Injection

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 injection pressures. However, excessive injection pressure may fracture the receiving formation causing the escape of produced water into freshwater or other mineral bearing formations. Injection well permits specifically identify the maximum allowable injection pressure which is based on an estimation of the injection formation fracture pressure. Also, additional energy (fuel) is necessary to obtain the higher discharge pressures and consequently results in increased air emissions.

Most coastal treatment systems are classified as closed systems which operate in the absence of air. As stated earlier, all of the non-commercial production facilities visited by EPA in 1992 used closed systems.[33] 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 can include gravity separation, gas flotation, and/or filtration. At coastal facilities in the Gulf of Mexico region, the most common form of pretreatment used is gravity separation (settling) and filtration using cartridge or bag filters. These technologies can be used as treatment prior to discharge or injection, and are described in detail in Section 5.2.3.1. The settling tanks are usually part of the existing BPT treatment system whereas, the filters are usually installed with the injection system to prevent the plugging of the injection formation. Filters are used especially at facilities located in water. Facilities located over land may opt to delete the filtration step and conduct periodic well workovers instead. Well workovers in water areas are more expensive (see Section XI.3.2.1.2). Filtration is discussed in more detail in the following section.

5.2.3 Filtration

Filtration is widely used for produced water treatment as a polishing step for the removal of suspended solids following the oil separation processes prior to discharger or injection. Filtration is generally utilized to improve the injection characteristics of produced water.[28] Filtration using cartridge filters is commonly used at coastal facilities in the Gulf of Mexico as a pretreatment step prior to injection to prevent plugging of the injection formation, and was included in the compliance cost estimates for the subsurface injection option for produced water in the coastal Gulf of Mexico region (see Section XI). Filtration can also be used as a treatment step prior to surface disposal.

Crossflow membrane filtration was investigated in detail in the development of the Offshore Effluent Guidelines where it was determined that widespread use is hampered by operational problems. Therefore, this technology was not selected for consideration in any options for the coastal subcategory.

5.2.3.1 Cartridge Filtration

Cartridge filtration involves the passage of water through disposable filter elements (cartridges) to remove solids. The cartridges are housed in a filter chamber that can hold from several, and up to 27 or more cartridges, depending on the flow capacity of the unit. Figure VIII-4 presents a schematic diagram of a typical cartridge filtration system. The filter element consists of a hollow cylinder of tightly wrapped twine that is several inches in diameter. The cartridges come in various grades ranging from five micrometers (u) nominal pore size to 50u or greater. The chamber is arranged so that water enters one end and is forced tangentially through the fibers of the cartridge to the center and out of one end of the cartridge. As solids build up within and on the outside of the cartridges, the pressure drop across the filter increases. The pressure drop is monitored by the operator and when the pressure drop exceeds a specified amount, usually between 10 psi and 20 psi, the filter chamber is taken out of service, opened up, and then the cartridges are replaced with new ones. The frequency of filter changeout is dependant on the quality and flowrate of the influent and was observed in the field to range from several days to a week or more.

A typical arrangement is two sets of filters arranged in parallel, with each set capable of processing the entire flow so that the flow can be alternated from one set to the other to allow for continuous operation during filter changeout. In some arrangements, each set of filters consist of two filters in series with finer grade filters in the downstream position. This arrangement extends the life of the finer filter which will clog up more quickly without prefiltration.

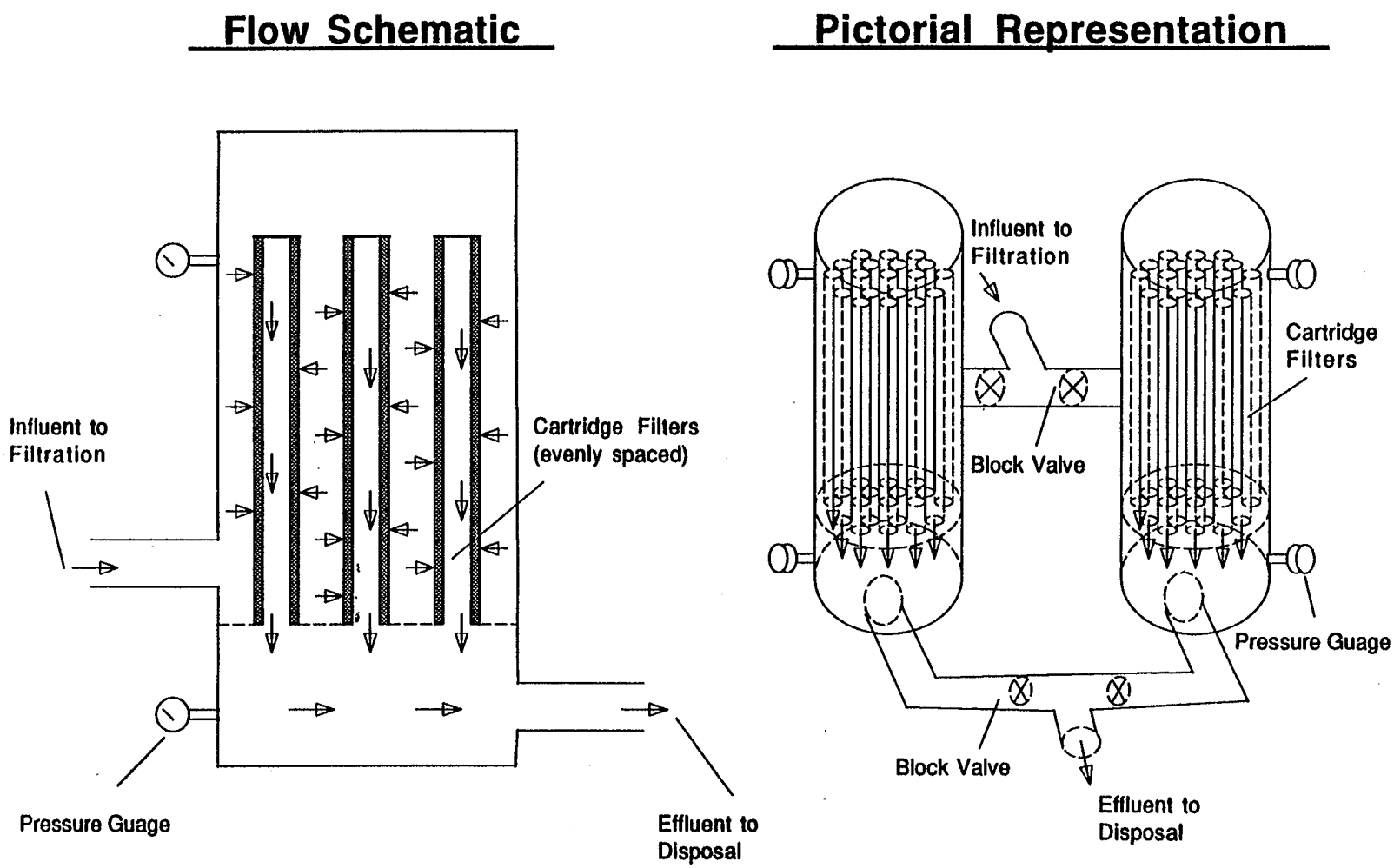

Figure VIII-4
Cartridge Filter

At the 10 production facilities investigated by EPA in 1992, cartridge filtration was used by three of the four facilities that utilized filtration as a pretreatment step prior to injection.[26] Table VIII-7 presents a summary of the produced water influent and effluent data from these three facilities. The cartridge filtration systems used at the three production facilities consisted of the following: Greenhill Petroleum at Bully Camp used a single stage 40u filter; Texaco at Bayou Sale and Texaco at Lake Salvador used a two-stage filtration system with 25u filters followed by 10u filters. It should be noted that each of these facilities used gas blanket systems to prevent air from coming into contact with the produced water. When the samples were collected, the samples developed an increase in turbidity after contact with air. This turbidity increase was the result of the precipitation of scale particles such as calcium carbonate that formed when the samples came in contact with air. This resulted in an increase in TSS. Therefore, the observed TSS concentrations in Table VIII-6 may not be representative of the actual concentrations as they existed in the closed systems.

Oil and Grease reduction averaged 28% across the filters from these three sites. However, one site realized an 8% increase in oil and grease concentrations. Of these three sites, only one site employed chemical addition during water separation and this was a surfactant. Oil and grease reduction across this filter averaged 30%, however, oil and grease effluent concentrations averaged 78.5 mg/l (the highest average oil and grease level of all 3 sites).[34]

A review of other pollutant reductions across the filters for these three sites does not show notable reductions. Other parameters including TOC, total phenols, aluminum, lead, benzene, and toluene showed increases of 1 to 5%.

A preliminary estimate of oil and grease effluent limitations using these data resulted in a daily maximum of 65 mg/l and a monthly average of 40 mg/l.[34] The long term average was estimated to be 24 mg/l. As a result of this information, EPA does not consider cartridge filtration as a candidate technology for BAT or NSPS because not only do pollutant concentrations sometimes increase, but for the pollutants that are removed, the removal is not as effective as improved gas flotation.

5.2.3.2 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

TABLE VIII-7
INFLUENT AND EFFLUENT POLLUTANT CONCENTRATION MEANS FROM CARTRIDGE FILTRATION[5]

Pollutant	Influent Mean (ug/l)	Effluent Mean (ug/l)	Pollutant	Influent Mean (ug/l)	Effluent Mean (ug/l)
CONVENTIONAL AND NON-CONVENTIONAL POLLUTANTS			**PRIORITY POLLUTANT VOLATILE ORGANICS**		
Total Recoverable Oil and Grease	49,903.50	31,426.17	Benzene	6,689.41	6,721.49
Total Suspended Solids	139,916.67	136,791.67	Ethylbenzene	63.24	63.10
Ammonia as Nitrogen	75,946.67	73,936.67	Toluene	5,190.74	5,227.20
BOD 5-day	742,833.33	677,083.33	**OTHER VOLATILE ORGANICS**		
Chemical Oxygen Demand (COD)	1,239,333.33	1,218,250.00	Carbon Disulfide	19.93	19.87
Chloride	70,753,000.00	71,423,083.33	m-Xylene	193.35	184.07
Fluoride	803.33	1,130.00	o+p Xylene	118.47	111.64
Nitrate/Nitrite	536.17	530.31	Vinyl Acetate	56.42	55.37
Sulfate	21,366.67	18,608.33	2-Butanone	221.59	223.08
Total Dissolved Solids	115,377,666.67	117,719,166.67	2-Hexanone	54.67	52.75
Total Organic Carbon (TOC)	325,150.00	328,175.00	2-Propanone	1,513.29	3,401.09
Total Phenols	2,362.62	2,407.25	**PRIORITY POLLUTANT SEMI-VOLATILE ORGANICS**		
Total Sulfide (Iodometric)	1,000.00	2,175.00	Di-n-Butyl Phthalate	39.79	32.50
PRIORITY POLLUTANT METALS			Naphthalene	222.04	215.07
Cadmium	60.93	60.86	Phenol	946.66	936.57
Chromium	139.92	134.80	**OTHER SEMI-VOLATILE ORGANICS**		
Copper	145.78	144.53	Benzoic Acid	7,637.95	7,355.70
Lead	430.10	422.33	Hexanoic Acid	1,761.82	2,064.23
Nickel	281.28	273.92	n-Decane	210.06	109.34
Selenium	786.67	820.00	n-Dodecane	155.67	252.75
Silver	560.13	590.21	n-Eicosane	55.17	50.33
Thallium	1,022.98	5,515.33	n-Hexadecane	221.50	201.25
Zinc	651.58	394.86	n-Octadecane	52.83	48.50
OTHER METALS			n-Tetradecane	72.88	72.74
Aluminum	1,403.17	1,426.42	o-Cresol	107.47	147.06
Barium	50,337.67	51,124.42	p-Cresol	312.70	257.83
Boron	28,059.33	28,750.67	1,2:3,4-Diepoxybutane	70.77	76.64
Calcium	2,411,483.33	2,413,591.67	2Methylnaphthalene	75.67	72.67
Cobalt	227.87	223.55	2,4-Dimethylphenol	183.74	184.64
Iron	15,934.83	15,993.83			
Magnesium	485,158.33	490,460.00			
Manganese	1,431.45	1,443.99			
Molybdenum	155.33	153.99			
Sodium	39,042,000.00	38,845,166.67			
Sulfur	2,150.00	2,195.00			
Tin	299.93	311.83			
Titanium	24.07	30.92			
Vanadium	324.28	322.39			
Yttrium	21.27	43.98			

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.[28] Figure VIII-5 shows the schematic of a multi-media granular filter.

The offshore three-facility study evaluated granular filtration systems designed to pretreat produced water following oil separation and prior to injection.[35] These particular operations inject produced water either because of a zero discharge permit requirement or for enhanced oil recovery. The three facilities 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.

EPA statistically analyzed the data from these facilities to determine effluent levels achievable from add-on granular media filtration technology. Table VIII-8 presents the performance of granular 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 flocculants to enhance separation, thus improving filtration performance.

5.2.3.3 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 VIII-6 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.[36] In addition to the high velocities of produced water across the membrane 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

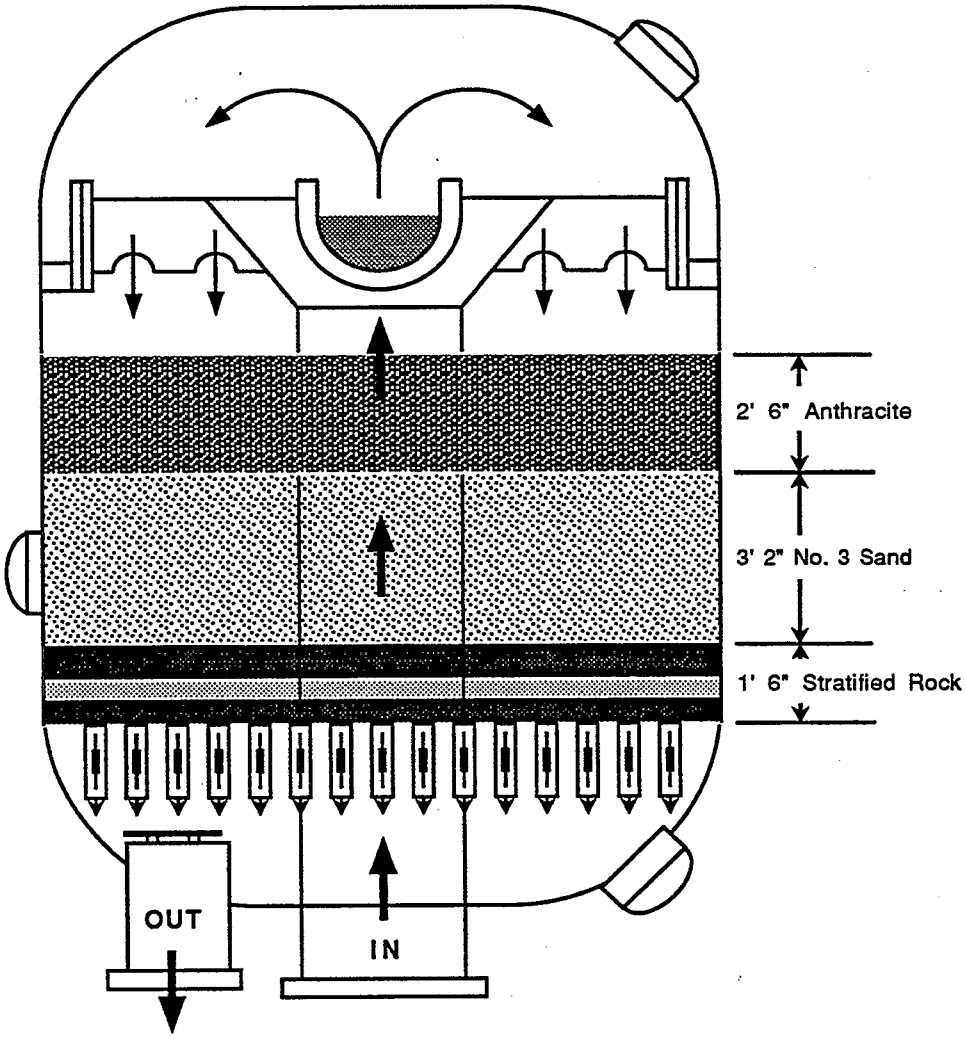

Figure VIII-5
Multi-Media Granular Filter

TABLE VIII-8

GRANULAR MEDIA FILTRATION PERFORMANCE[35]

	TSS (mg/l)[a]	O&G (mg/l)[b]
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%

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

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. This technology was investigated during the development of the Offshore Guidelines.

One type of crossflow membrane filtration system is currently being operated on two different platforms located in the Gulf of Mexico. One is a 5,000 barrel per day full scale unit processing a partial stream (slip stream) of the produced water for waterflood injection purposes.[37] The ceramic membranes used in these filtration modules are made of porous alumina. The alumina membranes have a pore size of 0.8 microns. 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. A backpulse cycle serves to constantly replace the "dynamic membrane" with a fresh

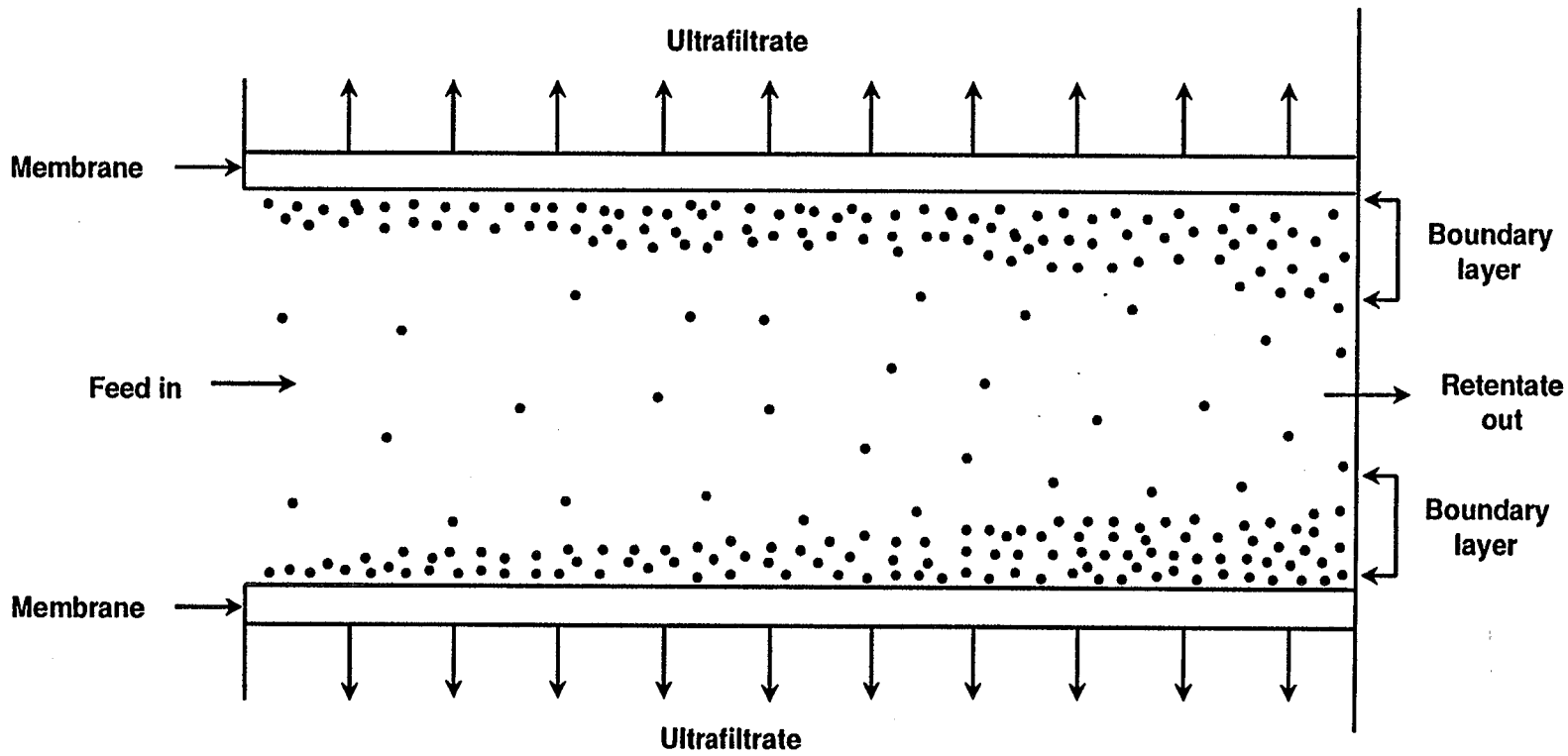

Figure VIII-6
Flow Dynamics of a Crossflow Filter

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.[38]

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 sampling program also analyzed the filtration process for removal efficiencies and potential concentration of TSS, organic compounds, metals, and radionuclides. Table VIII-9 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.[39]

A more detailed description of this technology can be found in the Offshore Development Document.[2]

TABLE VIII-9

MEMBRANE FILTRATION PERFORMANCE DATA FROM THE MEMBRANE FILTRATION STUDY[39]

Pollutant Parameter	Influent (μg except where noted)			Effluent (μg except where noted)		
	MIN*	MAX*	MED*	MIN*	MAX*	MED*
Oil & Grease						
Freon (mg/l)	16.33	42.67	19.67	3	7.67	4.67
Hexane (mg/l)	8.0	21.67	11.0	3.0	6.33	3.33
Total Petroleum Hydrocarbon (mg/l)	16.33	42.67	19.67	3.0	7.67	4.67
TSS (mg/l)	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

5.2.4 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 coastal 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 IX

MISCELLANEOUS WASTE— CHARACTERIZATION, CONTROL AND TREATMENT TECHNOLOGIES

1.0 INTRODUCTION

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

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

This section also includes a brief description of the minor waste streams associated with coastal 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 WELL TREATMENT, WORKOVER, AND COMPLETION FLUIDS

The definitions for well treatment, workover, and completion fluids (TWC fluids) are as follows:[1]

- **Well Treatment Fluids** are "any fluids 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."

Table IX-1 lists the data used in the compliance cost analysis for TWC fluids, presented in Section XII. These data include the number of wells discharging TWC fluids, the average volume discharged per job, and the total annual discharge volumes. The sources and derivation of these data are described in the following section.

TABLE IX-1

DATA USED IN TWC FLUID COMPLIANCE COST ANALYSIS

Fluid	Number of Discharging Wells (1992)	Average Volume Discharged per Well (bbls/job)	Total Volume Discharged per Year (bbs/yr)
Workover/Treatment	350	587	205,450
Completion	334	209	69,806
TOTAL	684	---	275,256

[1] Values are for coastal Gulf of Mexico operations only. No cost analysis was performed for Cook Inlet TWC fluids, based on the current practice of commingling TWC fluids with produced water (see Section XII for details regarding the cost analysis).

2.1 WELL TREATMENT, WORKOVER, AND COMPLETION FLUID VOLUMES

The volume of well treatment, workover, 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.[2] 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 fluid discharges. 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).[3] 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.[1] Discharge volumes for specific workover, completion and well treatment activities are presented in Table IX-2. This information indicates that discharges can range from 100 to 1,000 barrels.[4]

TABLE IX-2

TYPICAL VOLUMES FROM WELL TREATMENT, WORKOVER, AND COMPLETION OPERATIONS[4]

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

A statistical analysis of the results of the 1993 Coastal Questionnaire shows that in 1992, workover, treatment, and completion operations in the coastal Gulf of Mexico region discharged an average of 587 barrels of waste workover/treatment fluids and 209 barrels of waste completion fluids.[5] Workover and treatment fluids are presented in this document together because they are both used during production. Completion fluids are generated separately during completion just prior to production. For the purpose of developing compliance cost estimates, these volumes (presented in the survey as volume per year) are assumed to be average discharges per job because the survey results also indicate a workover/treatment fluid discharge frequency of between 0.78 and 1.87 times per year.[5] The numbers of wells discharging TWC fluids were derived from survey results and state Discharge Monitoring Report (DMR) data. The survey results indicate that in 1992, 219 wells discharged workover/treatment fluids and 209 wells discharged completion fluids.[5] A comparison of the number of wells in the survey to the number of wells for which DMR data are available revealed that the survey count of wells must be increased by a factor of 1.6 for an accurate count of existing wells.[6] Thus, the estimates of 219 wells discharging workover/treatment fluids and 209 wells discharging completion fluids were increased to 350 and 334, respectively. These well counts were then used to estimate the total annual volume of TWC fluids currently discharged: 205,450 barrels of workover/treatment fluid and 69,806 barrels of completion fluid, for a total of 275,256 barrels of TWC fluids discharged per year.

Volumes of fluids used for workover, completion, and well treatment operations were collected for a Cook Inlet Discharge Monitoring Study. Table IX-3 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.[7] Average discharge of TWC fluids ranged from 80 to 647 barrels per job.

TABLE IX-3

VOLUMES DISCHARGED PER JOB DURING WORKOVER, COMPLETION, AND WELL TREATMENT OPERATIONS FROM THE COOK INLET DMR STUDY[7]

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	320.8	148
Average	647	282	106	132	80

The 1993 Coastal Questionnaire also provided data regarding volumes of TWC fluids discharged in Cook Inlet, Alaska.[8] Volumes of workover/treatment fluids reported in the survey as discharged ranged from 300 to 18,000 barrels per well per year. These volumes were reported by two of the 13 active platforms in Cook Inlet. The 18,000-bbl discharge volume was a total of three discharges throughout the year, so the average per-job discharge volume is 3,150 bbls of workover/treatment fluid. Discharged completion fluid volumes ranged from 360 to 2,720 barrels per well for the year, and were reported for four wells on two different platforms. The average per-job discharge volume is 2,243 bbls of completion fluids. A total annual TWC discharge volume for all platforms in Cook Inlet was

calculated to be 58,574 barrels per year, based on the above per-job volumes and a seven-year schedule for drilling new wells and recompletions provided by Cook Inlet operators.[9] All discharges of TWC fluids to Cook Inlet reported in the survey were commingled with produced water for treatment prior to discharge.

2.2 WELL TREATMENT, WORKOVER, AND COMPLETION FLUIDS CHARACTERISTICS

2.2.1 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."[2] 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.[10]

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.[11] The solutions remain in the formation for 12 to 24 hours and are then pumped back to the surface.[2]

Common well treatment fluids include: hydrofluoric acid, hydrochloric acid, ethylene diaminetetracetic 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 anti-sludging agents.[4] Additives include: iron sequestering agents, corrosion inhibitors, surfactants, viscosifiers, and fluid diverters.[12] 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.[11] A corrosion inhibitor is always used during an acid stimulation job because the acids used are extremely corrosive to the steel piping and equipment.[2,13] Table IX-4 lists some of the typical chemicals used during well treatment.

TABLE IX-4

WELL TREATMENT CHEMICALS[14]

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-sulfonic acid 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 siliceous 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%

2.2.2 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.[3] 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.[14] 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.[15] Commonly used bridging agents are: ground calcium carbonate, sodium chloride, oil soluble resins, and calcium lignosulfonates.[16] The fluids are selected to be compatible with the formation to minimize damage to the formation and should perform the following functions.[4,16,17]

- 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.[16] 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.[17] Table IX-5 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.[16]

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.[16]

TABLE IX-5

COMMON BRINE SOLUTIONS USED IN WORKOVER AND COMPLETION OPERATIONS[16]

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.

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.[16]

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.[2] 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 commercially available 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. The primary functions of additives in completion and workover fluids are listed in the guide 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 filtration reducers are added to reduce fluid loss to the formation and can include bentonite clays, sodium carboxymethylcellulose, and pregelatinized starch.[18] Table IX-6 identifies specific additives to completion and workover fluids.

TABLE IX-6

ADDITIVES TO COMPLETION AND WORKOVER FLUIDS[4]

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.[12]

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

The most comprehensive source of analytical data for TWC fluids is an ongoing study of "associated wastes" by the EPA Office of Solid Waste (OSW), Waste Management Division.[19,21] The term "associated wastes" is used in the OSW study to describe miscellaneous and minor wastes associated with the exploration, development, and production of oil and gas resources. This study includes data from samples of TWC fluids collected in Texas, New Mexico, and Oklahoma during sampling efforts in 1992. Table IX-7 provides the average concentrations of pollutants found in selected TWC fluid samples from the OSW study.[20] In general, the pollutant characteristics of TWC fluids vary considerably from job to job. Therefore, the data in Table IX-7 are listed as ranges as well as averages.

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

TABLE IX-7
POLLUTANT CONCENTRATIONS IN TREATMENT, WORKOVER, AND COMPLETION FLUIDS[19]

Pollutant Parameter	Pollutant Concentration (µg/l)	
	Range	Average
Conventionals		
Oil & Grease	15,000.0 - 722,000.0	231,688.00
Solids, Total Suspended	65,500.0 - 1,620,000.0	520,375.00
Priority Pollutant Organics		
Benzene	477.0 - 2,204.0	1,341.00
Ethylbenzene	154.0 - 2,144.0	1,149.00
Methyl Chloride (Chloromethane)	0.0 - 57.0	29.00
Toluene	298.0 - 1,484	891.00
Fluorene	0.0 - 123.0	62.00
Naphthalene	0.0 - 1,050.0	525.00
Phenanthrene	0.0 - 128.0	64.00
Phenol	255.0 - 271.0	263.00
Priority Pollutant Metals		
Antimony	0.0 - 148.0	29.60
Arsenic	0.0 - 693.0	166.00
Beryllium	0.0 - 25.1	8.64
Cadmium	7.6 - 82.3	26.08
Chromium	48.0 - 1,320.0	616.82
Copper	0.0 - 1,780.0	277.20
Lead	0.0 - 6,880.0	1,376.00
Nickel	0.0 - 467.0	115.52
Selenium	0.0 - 139.0	42.94
Silver	0.0 - 8.0	1.60
Thallium	0.0 - 67.3	13.46
Zinc	0.0 - 1,330	362.94
Other Non-Conventionals		
Aluminum	0.0 - 13,100.0	6,468.40
Barium	66.5 - 3,360.0	498.10
Boron	4,840.0 - 45,200.0	15,042.00
Calcium	1,070,000.0 - 28,000,000.0	10,284,000.00
Cobalt	0.0 - 40.9	8.18
Cyanide, Total	0.0 - 52.0	52.00
Iron	7,190.0 - 906,000.0	384,412.00
Manganese	187.0 - 18,800.0	5,146.00
Magnesium	10,400.0 - 13,500,000.0	5,052,280.00
Molybdenum	0.0 - 167.0	63.00
Sodium	7,170,000.0 - 45,200,000.0	18,886,000.00
Strontium	21,100.0 - 343,000.0	142,720.00
Sulfur	72,600.0 - 646,000.0	245,300.00
Tin	0.0 - 135.0	27.00
Titanium	0.0 - 283.0	74.58
Vanadium	0.0 - 4,850.0	1,156.00
Yttrium	0.0 - 131.0	41.92
Acetone	908.0 - 13,508.0	7,205.00
Methyl Ethyl Ketone (2-Butanone)	0.0 - 115.0	58.00
M-Xylene	335.0 - 3,235.0	1,785.00
O-+P-Xylene	161.0 - 1,619.0	890.00
4-Methyl-2-Pentanone	198.0 - 5,862.0	3,028.00
Dibenzofuran	136.0 - 138.0	137.00
Dibenzothiophene	0.0 - 222.0	111.00
N-Decane (N-C10)	0.0 - 550.0	275.00
N-Docosane (N-C22)	237.0 - 1,304.0	771.00
N-Dodecane (N-C12)	0.0 - 1,152.0	576.00
N-Eicosane (N-C20)	0.0 - 451.0	226.00
N-Hexacosane (N-C26)	173.0 - 789.0	481.00
N-Hexadecane (N-C16)	0.0 - 808.0	404.00
N-Octacosane (N-C28)	0.0 - 422.0	211.00
N-Octadecane (N-C18)	281.0 - 1,868.0	1,075.00
N-Tetracosane (N-C24)	312.0 - 1,289.0	801.00
N-Tetradecane (N-C14)	513.0 - 1,961.0	1,237.00
P-Cymene	0.0 - 144.0	72.00
Pentamethylbenzene	0.0 - 108.0	54.00
1-Methylfluorene	0.0 - 163.0	82.00
2-Methylnaphthalene	0.0 - 1,634.0	817.00

operations. Samples were collected of fluids during five workover operations (one using weak acid, EDTA), two completion operations, and three well treatments using acid.[7]

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 IX-8 summarizes the analytical results from the Cook Inlet Discharge Monitoring Study.

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

2.3.1 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. EPA's general permit limiting the discharges from coastal oil and gas drilling operations in Texas and Louisiana further prohibits discharges of TWC fluids to freshwater areas (58 FR 49126). 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.

Treatment and disposal of well treatment, workover, and completion fluids with the produced water varies depending on how the fluids resurface, their reusability, and their volume in relation to produced waters they may be commingled with. The fluids are often commingled with the produced waters, especially where the proportion of produced water to TWC fluids is high enough to overcome the interference the TWC fluids may have on the produced water treatment system. 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 large concentrated slugs of TWC fluids.[11] Operators in Alaska also treat and dispose of these fluids with their produced water.[8,23] In California, facilities commingle the workover, completion and well treatment fluids with the produced water.[2]

TABLE IX-8

ANALYTICAL RESULTS FROM THE COOK INLET DISCHARGE MONITORING STUDY[7]

	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)

TWC fluids may be treated separately from the production fluid stream if they resurface as a discrete slug. It is especially advantageous to separately collect them if they are heavily weighted and can be reused. 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. However, treatment fluids are not reused because they react with the formation and lose their treatment ability.[2]

2.3.2 Additional Technologies Considered

Additional controls considered for this proposed rulemaking are limitations on oil and grease or zero discharge. The technology basis for these other controls on TWC fluids is commingling and treating with the produced water or sending the fluids separately to commercial disposal facilities. A detailed discussion of produced water treatment technology is presented in Section VIII.

3.0 DECK DRAINAGE

For coastal operations in the Gulf of Mexico, EPA investigated the deck drainage generated from drilling operations and production operations separately. Generally, deck drainage generated during drilling may vary in volume, characteristics, and its method of collection from that generated during production. Deck drainage from production operations occurs over a long period of time while drilling operations occur only for a relatively short and finite period of time. However, this distinction can not be made in Cook Inlet, since both drilling and production operations occur simultaneously on the same platform.

3.1 DECK DRAINAGE SOURCES

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

For drilling operations this includes drainage from the drilling deck itself. For land-based drilling operations, deck drainage includes runoff from the entire area within the levee surrounding the drilling operation which often includes parking areas plus office and living quarters. Deck drainage at land-based drilling operations is collected in a ditch that surrounds the entire drilling operation. Just outside of the ditch is a levee constructed of the material excavated from the ditch. This combined levee and ditch,

referred to as the ring levee, prevents contaminated runoff from exiting the site and prevents uncontaminated offsite runoff from entering the site.

For water-based (e.g., posted-barge) drilling operations, deck drainage includes drainage from the drilling deck itself plus all process area drains and exposed areas. Deck drainage is collected in a sump tank and is then pumped into a barge for reuse or disposal. Deck drainage from relatively uncontaminated areas such as heliports are often collected and discharged separately from other deck drainage sources.

For production operations, deck drainage primarily consists of runoff from diked separation and treatment equipment and storage tank areas. The deck drainage can include oil and produced water from spills and leaking equipment, wastes from tank and equipment cleaning operations, and spilled process treatment chemicals. The deck drainage is usually collected in a sump or skim tank for treatment and discharge or it is commingled with produced water for treatment and disposal.

3.2 DECK DRAINAGE VOLUMES

3.2.1 Total Volumes

Table IX-9 presents the overall total volume of deck drainage disposed by both drilling and production operations in the Gulf of Mexico and Cook Inlet.

TABLE IX-9

ANNUAL VOLUME OF DECK DRAINAGE DISPOSED

Region	Drilling Operations (bpy)	Production Operations (bpy)	Total (bpy)
Gulf of Mexico	937,286	9,932,332	10,869,618
Cook Inlet	628,475		628,475
Total			**11,498,093**

3.2.2 Gulf of Mexico-Production Operations

The predominant source of deck drainage at production facilities in the Gulf coastal region is from rain falling within bermed and diked areas. During the 1992 EPA 10 Production Facility Sampling

Programs, it was observed that deck drainage collection systems can cover areas ranging from several hundred square feet for small satellite tank batteries to much larger areas covering tens of thousands of square feet. The New Orleans area receives an average annual rainfall of 53.7 inches of rain compared to 14.7 inches in Anchorage, Alaska.[24] The statistical analysis of the 1993 Coastal Oil and Gas Questionnaire data estimated that the average volume of deck drainage from production facilities is 11,644 bpy.[5] By multiplying this value with the estimated 853 total number of production facilities,[6] the result is an estimated total annual deck drainage volume of 9,932,332 bbls for all production facilities in the Gulf coastal region. Using the average deck drainage volume of 11,644 bpy and the rainfall reported for the New Orleans area in 1992 of 60 inches[25] the area covered by the average production facility is estimated to be 9,806 square feet.

For most of the facilities, the proportion of deck drainage to produced water volume will be low. The estimated average facility produced water volume reported in the survey was 701,663 bpy for facilities that inject and 754,762 bpy for facilities that surface discharge.[5] The average deck drainage volume of 11,644 bpy is only 1.7% and 1.5% respectively of these average produced water volumes.

Although no one reported that they injected deck drainage in Question A42b of the Questionnaire, the Summary Statistics indicate that, based on the response to Questions A39b, 19.5% of the facilities that reported deck drainage data do not discharge produced water and at the same time commingle deck drainage along with the produced water for disposal. Therefore, EPA estimates that 7,995,527 bbls (80.5%) of the total estimated volume generated by production operations is being surface discharged.

3.2.3 Gulf of Mexico-Drilling Operations

Because of the significant differences in the deck drainage collection area covered and the deckdrainage handling equipment, EPA investigated deck drainage from land-based and water-based drilling operations as separate sources. The two data sources that were investigated to obtain estimates of the average volumes of deck drainage generated for disposal from land-based and water-based drilling operations were the 1993 Coastal Questionnaire data and the three coastal drilling site visits conducted by EPA in 1992. After a review of the Coastal Questionnaire and the trip reports, it was determined that a different method for estimating deck drainage volumes would be necessary for land-based versus water-based operations. These methods are discussed below.

3.2.3.1 Total Deck Drainage Volumes

Table IX-10 presents the per well and overall total volumes of deck drainage generated by water-based drilling operations in the Gulf of Mexico region. Tables IX-11 and IX-12 present the per well and overall total volumes of deck drainage generated by drilling operations in the Gulf of Mexico region based on the data and assumptions presented below.

TABLE IX-10

ANNUAL DECK DRAINAGE VOLUMES CURRENTLY DISCHARGED FROM WATER-BASED DRILLING OPERATIONS IN THE COASTAL GULF OF MEXICO REGION

Type of Well	Total Number of Wells[a]	Volume Discharged per Well (bbl)[b]	Total Volume Discharged (bbl)
New and Exploratory	152.2	516	78,535
Recompletions and Sidetracks	182.4	567	103,421
Total	**334.6**	**--**	**181,956**

a See Section 3.2.3.3
b See Section 3.2.3.4

TABLE IX-11

LAND-BASED DRILLING OPERATIONS DECK DRAINAGE PER WELL VOLUMES

Type of Well	Drilling Days	Volume Generated (bbl)	Volume Disposed (bbl)	Volume Reused (bbl)
New and Exploratory[a]	30	7,876	5,901	1,975
Recompletion and Sidetracks[b]	15	3,938	2,766	1,172

a See Section 3.2.3.5
b See Section 3.2.3.6

TABLE IX-12

LAND-BASED DRILLING OPERATIONS DECK DRAINAGE TOTAL VOLUMES ALL WELLS

Type of Well	Total Number of Wells[a]	Volume Generated[b] (bbl)	Volume Disposed[b] (bbl)	Volume Reused[b] (bbl)
New and Exploratory	79.8	628,505	470,900	157,605
Recompletion and Sidetracks	95.6	376,473	264,430	112,043
Total	**175.4**	**1,004,978**	**755,330**	**269,648**

a See Section 3.2.3.3
b (Number of Wells) X (Per Well Volumes in Table IX-11)

3.2.3.2 Estimation of the Proportion of Land-based Versus Water-based Drilling Operations

It is important to distinguish between land- and water-based drilling operations because land-based systems cover a larger area. Such systems utilize ring levels which tend to collect more rainwater. Answer to three questions in the 1993 Coastal Oil and Gas Questionnaire were used to estimate the proportions of land- and water-based drilling rigs. One is the reported type of drilling rig used for the injection wells is Question A18. Although these are injection wells and not production wells, it can be argued that the location of injection wells is likely to be proportionately the same as most of the production wells at a typical injection facility. The second and third sources come from two questions in Table B-7 requesting information on the number of wells that reported using either trucks or barges for hauling drilling waste. Question B27 requests the transport capacity, and Question B28 requests the number of vessels. In both cases, only barge and truck responses were counted since tugs are used to move the barges. Table IX-13 shows the number of facilities or drilled wells in the survey that indicated truck- or barge-based operations in each of these questions. The percentages of land-based versus water-based responses for all three sources were then averaged together to get the estimated overall proportion of each type of well in the region.

3.2.3.3 Numbers of Wells

Using the information reported in Question B2 in the Coastal Questionnaire, the well-type data were divided into six categories; "exploratory," "new production," "new and exploratory," "recompletion," "sidetrack of existing well," and "other and service". The estimated total wells for the

TABLE IX-13
PROPORTION OF LAND-BASED VERSUS BARGE-BASED OPERATIONS REPORTED IN THE COASTAL SURVEY

Type of Response	Number of Responses to Question A18[a]	% of Total	Number of Responses to Question B27[b]	% of Total	Number of Responses to Question B28[c]	% of Total	Average %
Truck	26	37.7%	9	34.6%	8	30.8%	34.4%
Barge	43	62.3%	17	65.4%	18	69.2%	65.6%
Total	69	100%	26	100%	26	100%	100%

[a] Question A18: What was the rig configuration for your injection well? Land-based, barge-based, or other?
[b] Question B27: What was the chosen mode of transporting drilling waste and its capacity? Barge, truck, tug, or other?
[c] Question B28: How many vessels or vehicles were required to dispose of drilling waste?

Gulf of Mexico coastal area that belong in each of these categories are provided in Table IX-14. Since the sample size was small for "exploratory" and "sidetrack of existing well" (only four for each), these two categories were combined with "new production" and "recompletion," respectively. In addition, the "other and service" wells were predominantly "rig workovers" and some "through-tubing plug backs". Since "other and service" wells mostly were not drilling operations, they are not included in this analysis. These numbers are used to calculate estimated annual deck drainage volumes for each type of drilling operation. Table IX-15 presents the estimated number of wells in these categories that are land-based and barge-based using the percentage split described in Table IX-13. For the purposes of estimating the volumes of deck drainage generated, EPA assumed that new production and exploratory wells are similar in nature and thus are grouped together. EPA also assumed the same is true for recompletions and sidetracks of existing wells.

3.2.3.4 Volumes Generated Per Well

The data in Table IX-13 show that, based on a review of the Coastal Questionnaire, the majority of the responses were from water-based operations. The one water-based drilling operation from the three EPA coastal drilling site visits was an unusually deep well and did not report the deck drainage volume because it was combined with and included in the total volume reported for waste drilling mud and wash water.[26] Therefore, the average volume surface discharged from water-based drilling operations for exploratory and new production wells, which is 516, was selected for use in this analysis based on responses to the Coastal Survey database.

TABLE IX-14
ESTIMATED NUMBER OF WELLS DRILLED IN 1992 IN COASTAL GULF OF MEXICO AND DURATION OF DRILLING[5]

Type	Number	Days To Drill
Exploratory	45	9.8
New production	187	21.4
New and Exploratory	232	19.3
Recompletion	241	8.5
Sidetrack of existing	37	10.6
Recompletion and Sidetrack	278	-
Other and service	177	19[a]

a Only one well reported days drilling because most of these wells were "rig workovers" and thus were not drilled.

TABLE IX-15

NUMBER OF WELLS BY LOCATION AND WELL TYPE CATEGORIES

Access	Well Type	Total Wells Each Type	Land vs. Water Proportions	Number of Wells
Land	New & Exploratory	232	34.4%	79.8
Land	Recompletion & Sidetracks	278	34.4%	95.6
Water	New & Exploratory	232	65.6%	152.2
Water	Recompletion & Sidetracks	278	65.6%	182.4

A review of a printout of the Coastal Questionnaire database shows that the majority of the deck drainage reported in Table B-9 was from water-based drilling operations.[8] Only one entry was clearly land-based and reported that 1,069 bbls of deck drainage were generated and were trucked 30 miles to a commercial facility. The average volume of deck drainage discharged to surface waters from water-based operations, including all exploratory and new production wells except the one land-based well, was

516 bbls per drilling job. The volumes ranged from 60 bbls to 2,318 bbls. In general, the higher volumes were for deeper wells which take longer to drill and therefore generate more deck drainage.

For water-based recompletions and sidetracks of existing wells, the estimated average deck drainage volumes discharged for these categories are 824 bbls and 310 bbls respectively.[5] These volumes were averaged together to get the volume of 567 bbls discharged because of the low number of survey responses for each category; two and three, respectively. The values reported in the questionnaire database are the volumes disposed and thus already take into account any reduction in volume due to reuse of deck drainage as mud make-up water. This may explain why the recompletion volume is greater even though the drilling time is lower for recompletions.

A review of the site visit data in Table IX-16 shows that both of the land-based drilling operations were deeper wells and longer in duration than the estimated average well in the Coastal Questionnaire.[5] In the survey, the estimated average well depth was 8,429 ft for exploratory wells and 8,487 ft for new production wells, and the estimated average drilling duration was 10 days and 21 days, respectively. Because the site visit data appear to represent greater than average values, a methodology was developed for estimating the average volume of deck drainage generated by land-based drilling operations rather than use the site visit data directly. The methodology utilized the drill site dimensions, annual rainfall data, estimated mud make-up water volume and average drilling operation duration. Based on this methodology, EPA estimates that land-based drilling operations dispose of 5,901 bbls of deck drainage per well.[27] The assumptions used are described below.

3.2.3.5 Assumptions for New and Exploratory Wells

- Deck drainage and area runoff are collected in the cellar and ring levee ditch.
- The drilling pad area will be 350 ft x 350 ft with a total surface area of 122,500 sq ft. These were the dimensions of the ARCO drilling operation in the Sabine Wildlife Refuge and represent the minimum area requirements.[28]
- Drilling time will be 30 days. The estimated average drilling time from the Coastal Survey was approximately 20 days (see Table IX-14), however this did not include time to test the well and to plug and abandon or complete the well. The additional 10 days accounts for these activities.
- The amount of rainfall is based on the average 30-day rainfall for New Orleans Louisiana using the 1993 annual rainfall amount of 52.7 inches.[29] The 30-day average rainfall total is 4.33 inches.

TABLE IX-16

SUMMARY OF DECK DRAINAGE INFORMATION FROM THE THREE COASTAL DRILLING SAMPLING SITE VISITS IN LOUISIANA[26,28,30]

Operator/ Type of Operation	Waste Type	Mud Type/ Drilling Interval	Treatment and Disposal	Surface Area (sq ft)	Volume Generated (bbls)	Days of Drilling
UNOCAL/ Posted Barge	Deck Drainage	Water base/ 0-13,555 ft	Drains to shale barge	7,236	Commingled with water based mud. Total mud + water = 2,515 bbls	57
		Oil base/ 13,555- 19260 ft	Drains to shale barge then annularly injected	7,236	4,199 bbls of wash water was injected	123
	Rainwater	Both intervals	Drains to a sump	7,236	Not reported	180
ARCO/ Land Rig	Deck Drainage and Rainwater	Water base/ 0-TD(14,928 ft)	Contained in levee and trucked to commercial facility	122,500 sq ft	12,440	63
GAP Energy/ Land Rig	Deck Drainage and Rainwater	Water base/ 0-TD(12,860 ft)	Contained in levee and trucked to commercial facility; 8000 bbls were surface discharged during heavy rain	164,025 sq ft	7,060 (commercial) 8,000 (surface)	96

- Rainwater will be used as make up-water for drilling fluids.[30] The amount used will be equal to the volume of waste mud generated minus the solids content of the mud. The estimated average volume of mud disposed as reported in the Coastal Survey Statistics was 3,038.5 bbls. The drilling fluid solids content ranged from below 10% to around 35% by volume at the three sampled drilling operations.[26,28,30] A solids content of 35% will be used as a conservative estimate since it will result in a lower volume of deck drainage that is recycled. This results in a deck drainage reuse volume of 1,975 bbls.

3.2.3.6 Assumptions For Recompletion and Sidetrack of Existing Land-based Wells

- Table IX-14 shows that for recompletions and sidetracks, the average days to drill were 8.5 and 10.5 or roughly one half the time to drill a new well. Therefore, the amount of rainwater generated is assumed to be one-half that of newly drilled wells (i.e., one-half the average 30-day rainfall; 15 days duration). Although recompletions may use smaller equipment and smaller pads, there is not sufficient information available to estimate the size of the reduction in volume. The 15-day average rainfall total is 2.16 inches and is based on the New Orleans annual 1993 rainfall data.[29]

- Rainwater will be used as make-up water for drilling fluids.[30] The amount used will be equal to the volume of waste mud generated minus the solids content of the mud. The estimated average volume of mud disposed as reported in the Coastal Survey Statistics was 1,803 bbls (Note that this volume is close to half the volume reported for newly drilled wells). The drilling fluid solids content ranged from the low 20's to around 35% by volume at the three sampled drilling operations. A solids content of 35% will be used as a conservative estimate. This results in a deck drainage reuse volume of 1,172 bbls.

3.2.4 Cook Inlet Alaska

For Cook Inlet platforms, deck drainage can originate from both drilling and production activities and thus are different from the Gulf of Mexico operations discussed above. Table IX-17 presents the deck drainage volumes obtained from the Coastal Questionnaire and an EPA site visit. Of the 10 platforms in Cook Inlet that transfer produced fluids to shore for separation, only four treat and discharge their deck drainage at the platform. The remaining six commingle deck drainage with production fluids and transfer the combined stream to shore-based facilities for separation and disposal of the deck drainage along with the produced water. At the five platforms that separate produced fluids on the platform, deck drainage is treated along with the produced water and discharged through the skim pile. The arithmetic average of four reported discharge volumes (44,891 bpy) was used by EPA in studying costs and impacts of deck drainage options. By adding the reported volumes to the calculated volumes reported in Table IX-17, the total volume disposed from Cook Inlet platforms is estimated to be 628,475 bpy.

TABLE IX-17

ANNUAL DECK DRAINAGE VOLUMES DISPOSED IN COOK INLET, ALASKA

Facility	Platform	Deck Drainage Volume (bbl/yr)	
		Reported	Average[c]
Trading Bay	King Salmon	--	44,891
	Dolly Varden	4,000[a]	--
	Steelhead	--	44,891
	Monopod	--	44,891
	Grayling[d]	--	44,891
Granite Point	Spark	--	44,891
	Spurr	--	0
	Granite Point[d]	--	44,891
E. Foreland	SWEPI "A"[d]	65,000[a]	--
	SWEPI "C"[d]	81,000[a]	--
Dillon	Dillon[e]	--	44,891
Bruce	Bruce[e]	29,565 (max. 95,630)[b]	--
Anna	Anna[e]	--	44,891
Baker	Baker[e]	--	44,891
Tyonek "A"	Tyonek "A"[e]	--	44,891
Total			**628,475**

[a] Source: 1993 Coastal Oil and Gas Survey (Operators did not claim confidentiality of information for deck drainage data)
[b] Source: Wiedeman, May 1, 1993
[c] Average Volume = (4,000 + 65,000 + 81,000 + 29,565)/4 = 44,891 bbl/yr
[d] These platforms do not commingle deck drainage with produced fluids. Deck drainage is treated and discharged at the platforms.
[e] These platforms commingle deck drainage with produced water and discharge both at the platform after treatment.

3.3 DECK DRAINAGE CHARACTERISTICS

Oil and grease are the primary pollutants identified in the deck drainage waste stream. 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.[31]

EPA's analytical data for deck drainage comes from the data acquired during the Offshore Oil and Gas rulemaking effort. As part of this effort, EPA evaluated Discharge Monitoring Reports (DMRs) for deck drainage discharges from 32 oil companies located in the Gulf of Mexico.[32] 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 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 and grease. The DMR data included oil and grease concentrations of deck drainage discharges. Table IX-18 presents the monthly averages of deck drainage oil and grease concentrations for the two years evaluated. 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 and grease.

TABLE IX-18

CHARACTERISTICS OF DECK DRAINAGE FROM OFFSHORE GULF OF MEXICO PLATFORMS[32]

	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

Also, as part of the Offshore Oil and Gas rulemaking effort, EPA conducted a comprehensive 4-day sampling program at three oil and gas production facilities in June of 1989, 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. 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 from three separate oil and gas subcategories. 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).[33,34,35]

Samples of treated and untreated deck drainage were collected at two of the facilities; the THUMS facility and the Shell Beta Complex. The range of pollutant concentrations in untreated deck drainage are presented in Table IX-19. As can be seen from the data in Tables IX-18 and IX-19, the pollutant concentrations can vary widely from place-to-place and over time. In these samples, eight toxic metals were detected, most notably lead (ranging in concentration from 25 - 325 ug/l) and zinc (ranging in concentration from 2,970 - 6,980 ug/l). The presence of lead, copper and zinc may be related to the presence of these metals in standard drill pipe thread compound. Organics were also present including benzene, toluene, xylene and naphthalene. These organic pollutants are commonly found in oil.

The content and concentrations of contaminants in deck drainage can also depend on chemicals used and stored at the oil and gas facilities. An additional study on deck drainage in Cook Inlet reviewed during the development of the Offshore Guidelines showed that discharges from this wastestream may also contain paraffins, sodium hydroxide, ethylene glycol methanol and isopropanol.[36]

3.4 Deck Drainage Control and Treatment Technologies

3.4.1 BPT Technology

BPT limitations for deck drainage prohibit the discharge of free oil. Typical BPT technology for compliance with this limitation is a sump, or skim tank or skim pile which facilitates gravity separation of any floating oil prior to discharge of the deck drainage. Deck drainage treatment systems typically use gravity flow to convey the flow, and the skim tanks generally do not require a constant power source for operation. Thus, deck drainage generated at facilities located in powerless remote locations (such as satellite tank batteries) can be effectively treated.

3.4.1.1 Cook Inlet

Typical platforms such as those in Cook Inlet are equipped with drip pans and gutters to collect deck drainage. The drainage flows by gravity to 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. Figure IX-1 is a schematic of a generic production platform flow system. The water from the sump is discharged to the surface via a submerged outfall or a skim pile. Skim piles which are common only to relatively deep water platforms, such as in Cook Inlet, remove that portion of oil which quickly and easily separates from water (see Figure VIII-1). 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

TABLE IX-19

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	$151x10^4$-$568x10^4$		
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.

of no flow, oil will rise to the quiescent areas below the underside of inclined baffled plates where it coalesces. 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

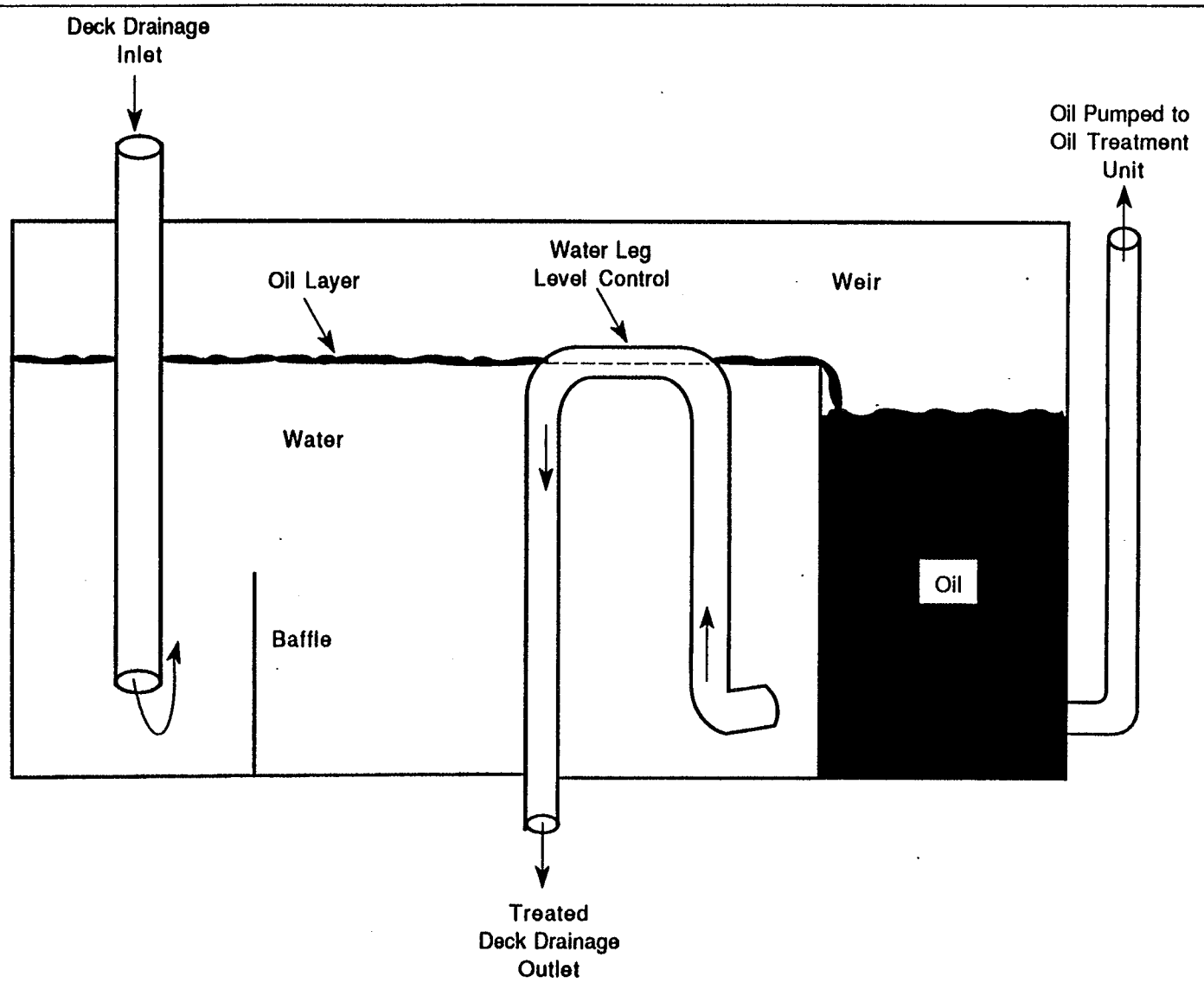

Figure IX-1
Deck Drainage Sump

with production oil. At some facilities deck drainage contaminated with oil is commingled with produced water and is treated in the produced water treatment system.

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.[36]

Some platforms in Cook Inlet 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]

At the Bruce Platform in Cook Inlet, deck drainage from diked areas flows to a 300-bbl skim tank where oil is skimmed off and pumped to the oil processing system. The effluent from the skim tank is then commingled with produced water in two 600-bbl settling tanks. The combined effluent is discharged 10 feet below the water surface.[23]

On the jackup drilling rig, Adriatic 8, contaminated deck drainage is retained in the drilling deck area using four inch collars. The deck drainage is collected in a 20-bbl skim tank that can hold approximately one week's worth of deck drainage. The water then passes through a 7-ft high by 2-ft diameter separator and is then discharged.[23]

3.4.1.2 Gulf of Mexico-Production Operations

Typical production operations in the Gulf area that use elevated platforms are equipped with drip pans and gutters to collect deck drainage and direct it to a sump where oil skimming occurs prior to discharge below the water surface. Skim piles are not used because of the generally shallow water. Figure IX-2 presents a schematic diagram of a sump/skim tank. In this tank, deck drainage enters near the bottom at one end and passes over a baffle into a quiescent zone where oil floats to the surface. The separated oil passes over a weir and is pumped to the oil-water treatment unit such as a gun barrel.

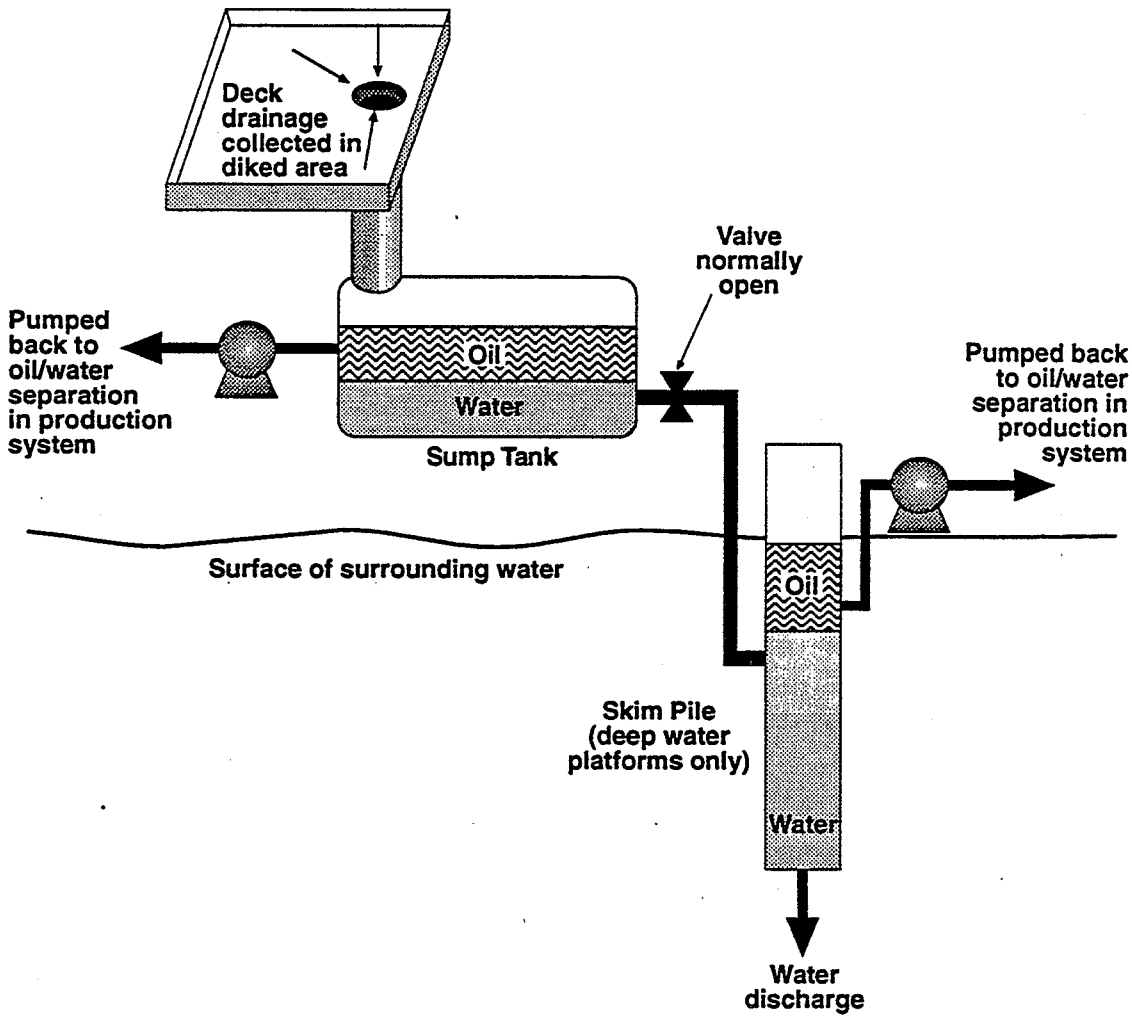

Figure IX-2
Deck Drainage Treatment System

Treated deck drainage exits the skim tank from a port near the bottom of the tank and passes through an inverted "U" shaped pipe and is discharged below the water surface. The inverted "U" shaped pipe controls the liquid depth in the tank and is referred to as the water leg. These tanks are usually installed below the deck near the water surface to take advantage of using gravity flow in the deck drainage collection system.

Operations that are located on land or fill are usually equipped with earthen or concrete beams with a depression in one area that acts as a sump to collect drainage. The collected water may be either sent to a treatment system, commingled with produced water for treatment and disposal, or discharged without treatment. Three of the 10 coastal facilities sampled by EPA in 1992 commingled deck drainage with produced water prior to treatment and subsurface injection.[37] Three facilities used skim tanks prior to surface discharge and the remaining five discharged deck drainage without treatment, if no sheen was visible.

3.4.1.3 Gulf of Mexico-Drilling Operations

Deck drainage is periodically pumped from the ring levee ditch or collection sump and is disposed by one or more of the following four methods: (1) hauled offsite in vacuum trucks or barges for disposal, (2) reused as make-up water in drilling fluids, (3) subsurface injection through the annulus of the intermediate casing of the well being drilled or (4) surface discharge.

Deck drainage from the drilling deck contains a considerable amount of drilling fluid and is almost always collected, treated, and disposed in the same manner as waste drilling fluids. For many land-based drilling operations in the Gulf region, at least a portion of the deck drainage, particularly site runoff, is used as make-up water for drilling fluid. For deck drainage that is not reused in this manner and does not meet the state discharge limitations, the treatment and disposal method is either annular injection or transportation to and disposal at an offsite commercial facility. For water-based drilling operations, deck drainage is collected in a sump tank and can be combined with waste mud for offsite disposal. Although deck drainage from oil-base drilling operations can be treated using gravity separation, EPA observed that the common practice is to dispose of the untreated water by injection or transport it to a commercial disposal facility.[26,28,30]

3.4.2 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" (SWEPI "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. 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, while some operators diverted deck drainage to a sump tank to be treated and discharged.[38] As noted earlier, three of the ten Gulf coastal production facilities visited by EPA in 1992 commingled deck drainage with produced water prior to treatment and disposal by subsurface injection. For platforms that use shore-based oil/water separation, the deck drainage wastewater that fails the sheen test is diverted and pumped to shore along with produced water for treatment. A corrosion inhibitor and/or an oxygen scavenger is usually added to compensate for the introduction of the oxygen-enriched deck drainage water.

Difficulties encountered in commingling the whole deck drainage waste stream with the produced waste water stream include:[12]

- The resulting flow variations could 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 sent to the produced water treatment system could create hydraulic overloading of the equipment because of the highly variable nature of the flow rate. An add-on treatment specifically designed to capture and treat deck drainage, other than the type of sump/skim pile systems typically used, 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 zero discharge for all deck drainage poses problems with storage and handling capacity during severe storm events, EPA considered the capturing of only the first 500 bbls (first flush) and commingling it with produced water for disposal at production operations and commingling it with drilling wastes for disposal at drilling operations. Rainfall in excess of the 500 bbl volume would be subject to BPT limitations. The volume of 500 bbls was selected because it is a standard storage tank volume and would capture approximately 3.5 inches of rainfall at an average production operation (see Section XIII.3.2). The installation of larger tanks was considered to be too costly.

The current BPT limitations allows for use of non-powered systems that utilize gravity to collect and treat deck drainage. The commingling of the first flush volume has several technical problems including:

- Above-deck storage tanks would require the installation of a sump and high capacity pumps (e.g.,two 200-gpm pumps) to handle sudden surges in flow.
- Many coastal facilities are unmanned and have no power source available to them. Generators or fuel powered pumps would be required at these locations that otherwise would not need them.
- Facilities that do not have a power source capable of driving high capacity pumps would need to use gravity to direct the first flush volume to the storage tank. This would require the installation of the tank below the deck which may not be feasible in many instances.
- Control systems that would prevent the overflow of an already full tank, during severe or back-to-back storms would be required.
- The storage tanks would require additional deck space that would add significant costs, especially for water-based facilities.
- Isolating the first flush at land-based drilling operations, that use ring levees, would be difficult because the first flush volume could become mixed with deck drainage already in the ring levee at the time of a storm event. The installation of a separate collection system, including pumps and tanks, would add significant cost.

The volume of contaminated deck drainage can be reduced by segregating the clean area of the site from the potentially contaminated area.[39] This involves using a segregation berm to separate the office trailer and parking/truck maneuvering areas which generate relatively little pollution from the

drilling equipment, pipe racks, and waste storage areas. Such a set up which also recycled the dirty water into the mud system was reported to result in a 40% savings to location and waste management costs.[39] Direct measurement of Figure 6 in the Longwell and Akers article indicated that 44% of the drill pad was segregated as the clean area and that the storage volume in the ditch (ditch length) was also reduced by 44%. The storm water from the non-contaminated side of the drilling site is assumed to be clean enough to be discharged without treatment. Other ways of reducing rainfall contamination are methods of "Best Management Practices" which are described in Section XVII of this document.

4.0 PRODUCED SAND

Produced sand consists of the accumulated formation sands and other particles (including scale) generated during production as well as the slurried particles used in hydraulic fracturing. This waste stream also includes sludges generated by chemical flocculation used in solids separation processes for produced water such as filtration or sedimentation. The following sections describe the sources, volumes, characteristics, and treatment methods for produced sand.

4.1 PRODUCED SAND SOURCES

Produced sand is generated during oil and gas production by the movement of sand particles in producing reservoirs into the wellbore, by silica material spilling off the face of the producing formation and by the precipitation of scale and other solid particles. The generation of produced sand usually occurs in reservoirs comprised of young, unconsolidated sand formations.[40] 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).[41]

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 and/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.[42] One source indicates that desanders or desilters (hydrocyclones) are used to remove sand if the volume produced is high.[41] However, observations during the EPA 1992 Production Sampling Program indicate that for

lower production volumes more typical of coastal situations, sand removal is primarily achieved by tank cleanouts and that desanders are seldom used.[37] 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.[43]

4.2 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.[41,42] Oil producing reservoirs will typically generate more produced sand than gas producing reservoirs. This is because oil reservoirs generate more liquids (both oil and water) which are more viscous than gas and thus the liquids will remove and carry the sand more easily to the surface than gas. Also, the greater water volumes associated with oil reservoirs will create more scale particles. 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.[44] Table IX-20 presents a summary of the produced sand volumes data.

TABLE IX-20
PRODUCED SAND VOLUMES GENERATED

	Gulf of Mexico		Cook Inlet	
Source	Produced Sand Generated	Frequency	Produced Sand Generated	Frequency
Oil & Gas Questionnaire	74 bbls[a]	1/2.9 yr[a]	365 bbl[8] 1 bbl[8] 1 bbl[8] 1 bbl[8]	--
Trip Reports	106 bbls[37] 400 bbls[37]	1/1 yr[37] 1/1 yr[37]	600 bbl[23]	1/2+yr[23]

a: Estimated average from SAIC, September 30, 1994.[5]

4.2.1 Gulf of Mexico

224 production separation facilities in the Gulf of Mexico provided produced sand data in the 1993 Coastal Questionnaire.[8] Of these 224, a total of 37 facilities reported produced sand generation

volumes. The average volume generated was 74 bbls. Since produced sand is not collected from process equipment every year, the survey only represents a snapshot of produced sand collection for the year of 1992. The average frequency of generation of produced sand for these 37 facilities ranged between 2.2 times per year and once every 2.9 years. Although only 16.5% of the facilities reported produced sand volume data, this does not indicate that 83.5% of the 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, or that the volume was unknown.

The annual sand generation rates obtained during EPA's 1992 10 production facility study ranged from 106 to 400 bbls for facilities with produced water flowrates of 6,462 and 7,000 bpd respectively.[37] In addition, one of the two commercial produced water injection facilities sampled by EPA in 1992 reported an annual sand generation rate of 50 bbls with an average produced water flowrate of 5,000 bpd.[45] It is likely that some of the produced sand in the produced water received by the commercial facility would have settled out in the production equipment and produced water storage tanks prior to being sent to commercial disposal.

The questionnaire indicates that only one of the operators surveyed discharged produced sand at three of their facilities in 1992. The operator indicated that this practice would be discontinued in the near future.[46] All other operators dispose of produced sands via landfarming, underground injection, landfilling, or onsite storage. The total sand production from the three sites discharging sand was 144 bbls which is a small proportion of produced sand generated in the region.

4.2.2 Cook Inlet

Four of the platforms in Cook Inlet reported produced sand generation volumes in the 1993 Coastal Questionnaire.[8] One reported generating 365 bbls in 1992 while the remaining three reported only one bbl for 1992. Operators of the Bruce Platform in Cook Inlet reported that they had removed 600-bbls of produced sand for disposal from their two 600-bbl produced water settling tanks two years prior to EPA's visit in August 1993.[23] Therefore, the amount generated per platform can vary greatly. The current produced sand disposal practice in Cook Inlet is zero discharge via land disposal and storage for future land disposal.[47,48] In the past, produced sand from the Bruce Platform had been sent to the Kenai Gas Field for storage. This produced sand has recently been ground and injected as part of a pilot project to grind and inject stored wastes and the contents of old reserve pits.[23]

4.3 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.[12] The oil content of unwashed produced sand can range from a trace (expected in sand from blowdown) to as much as 19 percent by volume.

During the EPA 1992 Production Sampling effort, samples of settling tank bottoms were collected at four facilities and analyzed for conventional, non-conventional, organic pollutants and metals and radionuclides.[37] These samples are considered representative of produced sand. Table IX-21 presents the maximum and minimum concentrations detected in these samples. Due to a limited volume available at some of these sites, not all analytes were analyzed for all of the samples. For the two samples that were analyzed for oil content, the concentration ranged from 12.7 to 19 percent. All toxic metals were present except silver, with most notable contributions from copper (32.15 mg/kg) and lead (171.94 mg/kg).[49] The toxic organic pollutants present were similar to those found in produced water including benzene, ethylbenzene, toluene, xylene, propanone, and phenanthrene.

4.4 PRODUCED SAND 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.[44] 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 IX-3 presents a schematic diagram of a closed hole perforated completion with gravel packing.

TABLE IX-21

RANGE OF POLLUTANT CONCENTRATIONS IN PRODUCED SAND FROM THE 1992 COASTAL PRODUCTION SAMPLING PROGRAM[49]

Pollutant	Units	Number of Samples	Number of Detects	Minimum Value	Maximum Value
CONVENTIONAL AND NON-CONVENTIONAL					
Total Recoverable Oil & Grease	µg/kg	3	3	84,000.00	328,562.87
Oil Content	%	2	2	12.70	19.00
Total Solids	µg/kg	3	3	76.00	1,052,084.21
BOD 5-day (Carbonaceous)	µg/kg	3	3	16,000.00	161,413.51
Total Organic Carbon (TOC)	µg/kg	3	3	20,000.00	285,693.11
Ph	Ph	3	3	6.70	10.50
Chloride	µg/kg	3	3	1,360.78	25,000.00
Fluoride	µg/kg	3	3	1.30	368.25
Nitrate/Nitrite	µg/kg	3	1	9.30	19.00
Total Releasable Sulfide	µg/kg	3	1	120.00	200.00
Total Sulfide (Isometric)	µg/kg	3	2	26.14	2,000.00
PRIORITY POLLUTANT METALS					
Antimony	mg/kg	4	1	0.30	4.50
Arsenic	mg/kg	4	2	8.30	34.0* 0
Beryllium	mg/kg	4	3	0.10	0.20
Cadmium	mg/kg	4	2	0.93	2.20
Chromium	mg/kg	4	4	3.70	26.60
Copper	mg/kg	4	4	6.50	72.00
Lead	mg/kg	4	4	25.70	510.00
Mercury	mg/kg	4	1	0.10	0.20
Nickel	mg/kg	4	4	4.90	12.50
Selenium	mg/kg	4	1	4.00	4.00
Thallium	mg/kg	4	1	2.70	2.70
Zinc	mg/kg	4	4	63.80	11,700.00
NON-PRIORITY POLLUTANT METALS					
Aluminum	mg/kg	4	4	879.00	71,100.00
Barium	mg/kg	4	4	201.00	3,680.00
Boron	mg/kg	4	4	26.80	328.00
Calcium	mg/kg	4	4	6,020.00	23,500.00
Cobalt	mg/kg	4	4	1.70	3.50
Iron	mg/kg	4	4	4,650.00	14,300.00
Magnesium	mg/kg	4	4	602.00	3,030.00
Manganese	mg/kg	4	4	54.50	121.00
Molybdenum	mg/kg	4	2	1.60	15.70
Sodium	mg/kg	4	4	13,300.00	32,800.00
Strontium	mg/kg	2	2	131.00	256.00
Sulfur	mg/kg	4	4	1,570.00	5,890.00
Tin	mg/kg	4	3	3.80	349.00
Titanium	mg/kg	4	4	14.60	60.80
Vanadium	mg/kg	4	4	2.90	18.60
Yttrium	mg/kg	4	4	2.30	5.80
PRIORITY POLLUTANT VOLATILE ORGANICS					
Benzene	µg/kg	3	3	55,352.86	283,445.00
Ethylbenzene	µg/kg	3	3	33,170.00	296,995.00

TABLE IX-21

RANGE OF POLLUTANT CONCENTRATIONS IN PRODUCED SAND FROM THE 1992 COASTAL PRODUCTION SAMPLING PROGRAM[49]

Pollutant	Units	Number of Samples	Number of Detects	Minimum Value	Maximum Value
Methylene Chloride	µg/kg	3	2	193.37	54,140.35
Toluene	µg/kg	3	3	89,417.14	355,835.00
Trichlorofluoromethane	µg/kg	3	2	30,707.14	250,754.39
NON-PRIORITY POLLUTANT VOLATILE ORGANICS					
M-Xylene	µg/kg	3	3	18,827.14	161,610.00
O+P Xylene	µg/kg	3	2	70,039.68	116,645.00
2-Propanone	µg/kg	3	1	222,183.05	222,183.05
PRIORITY POLLUTANT SEMI-VOLATILE ORGANICS					
Acenaphthene	µg/kg	3	1	8,511.33	8,511.33
Anthracene	µg/kg	3	1	10,442.33	10,442.33
Fluorene	µg/kg	3	2	12,115.33	19,521.00
Naphthalene	µg/kg	3	3	46,547.00	57,003.33
Phenanthrene	µg/kg	3	2	19,739.00	26,779.67
2,4,6-Trichlorophenol	µg/kg	3	1	139,153.33	139,533.33
NON-PRIORITY POLLUTANT SEMI-VOLATILE ORGANICS					
Acetophenone	µg/kg	3	1	50,996.67	50,996.67
Biphenyl	µg/kg	3	2	25,620.33	50,769.33
Dibenzofuran	µg/kg	3	1	15,397.00	15,397.00
Dibenzothiophene	µg/kg	3	2	4,873.33	6,826.33
n-Decane	µg/kg	3	3	7,302.67	169,263.33
n-Docosane	µg/kg	3	3	53,659.33	199,183.33
n-Dodecane	µg/kg	3	3	50,642.33	716,843.33
n-Eicosane	µg/kg	3	3	139,153.33	333,090.00
n-Hexacosane	µg/kg	3	3	20,380.00	123,716.67
n-Hexadecane	µg/kg	3	3	250,070.00	554,033.33
n-Octacosane	µg/kg	3	3	5,543.67	150,746.67
n-Octadecane	µg/kg	3	3	225,183.33	463,686.67
n-Tetracosane	µg/kg	3	3	64,200.00	187,440.00
n-Tetradecane	µg/kg	3	3	253,220.00	439,433.33
n-Triacontane	µg/kg	3	3	16,789.00	393,873.33
1-Methylfluorene	µg/kg	3	3	31,473.33	88,670.00
1-Methylphenanthrene	µg/kg	3	2	10,717.33	38,270.00
1-Phenylnaphthalene	µg/kg	3	1	5,124.00	5,124.00
2-Isopropylnaphthalene	µg/kg	3	1	39,190.00	39,190.00
2-Methylnaphthalene	µg/kg	3	2	96,533.33	155,923.33
2-Phenylnaphthalene	µg/kg	3	2	6,012.00	6,871.33
3,6-Dimethylphenanthrene	µg/kg	3	1	19,858.33	62,333.33
4-Aminobiphenyl	µg/kg	3	1	31,025.67	31,025.67
RADIONUCLIDES					
Gross Alpha	pCi/g	4	1	834.00	872.00
Gross Beta	pCi/g	4	4	12.00	668.00
Lead 210	pCi/g	4	3	4.20	11.70
Radium 226	pCi/g	5	4	2.60	6.90
Radium 228	pCi/g	5	3	2.70	6.50

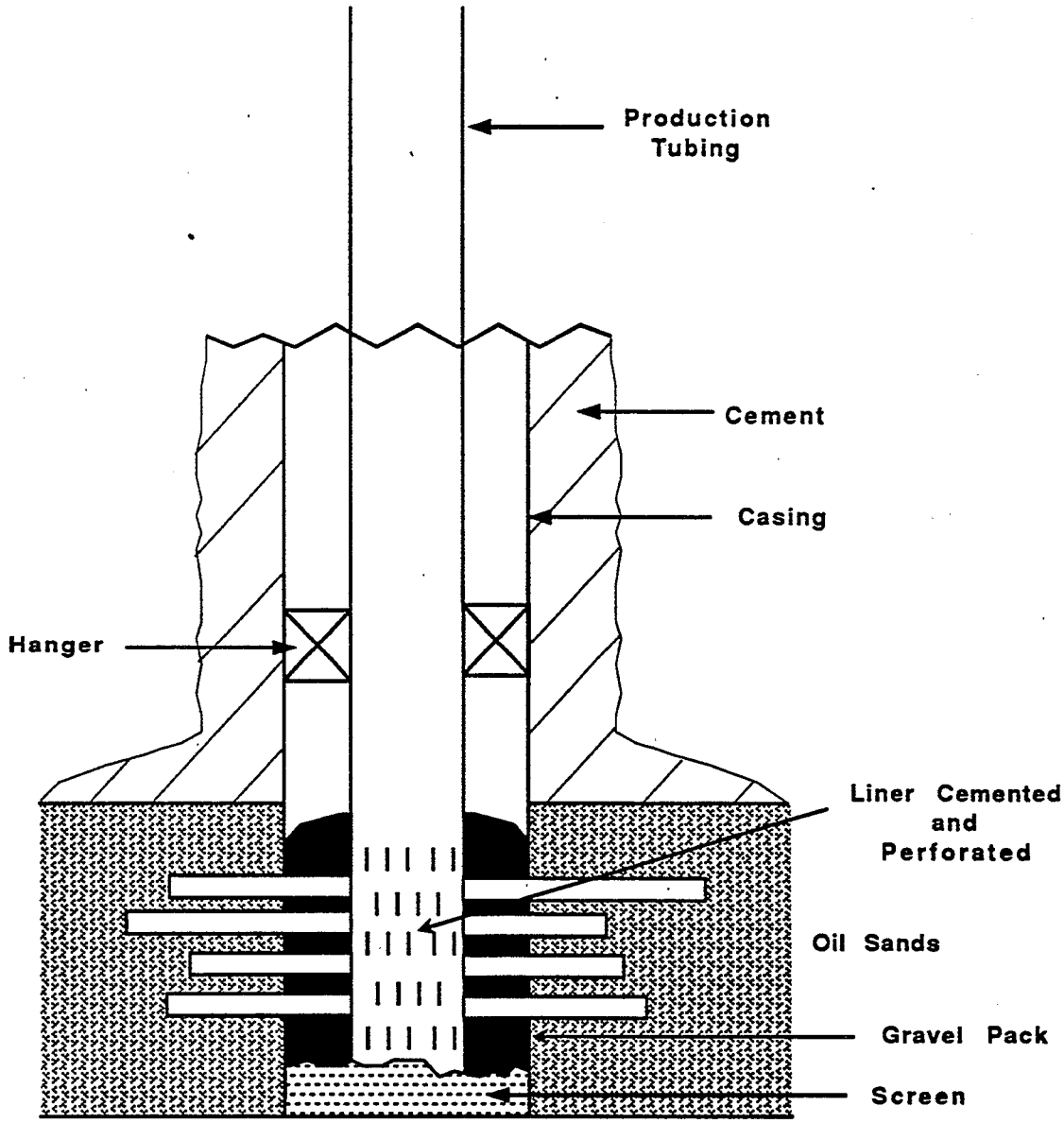

Figure IX-3
Closed Hole Perforated Completion (With Gravel Pack)

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.[44] In addition, produced sand contained in liquids such as oil and water do not pose as great a physical erosion problem due to the lower velocities of these fluids and the lubricating properties of the liquids.

4.4.1 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 land application or hauling the sand to a commercial facility for final disposal.

Of the 10 coastal production facilities in the Gulf of Mexico region visited by EPA in 1992, only one reported onsite disposal of produced sand. At this facility located in Texas, produced sand is removed from the produced water treatment tanks and deposited on the ground within the diked area. Samples are collected for oil and grease analysis and if the concentration is below 1.0 percent, they are allowed to dispose of the produced sand by spreading it on their sand and gravel roads.[50] The remaining nine production facilities reported that they transport produced sand to commercial disposal facilities.

Data from the 1993 Coastal Questionnaire indicate that 4.6 percent of the coastal facilities in the Gulf of Mexico inject produced sand and that the remainder is either landfilled, stored onsite for future disposal, hauled offsite for disposal or is encapsulated and disposed in abandoned wells.[5]

Since only one operator in the Gulf of Mexico reported discharge of produced sand and that operator reported their intention to discontinue this practice in the near future, this information indicates that the current practice of the industry is zero discharge. The one operator that reported discharge of produced sand indicated that the sand was first treated by sand washing prior to disposal.[46] A detailed discussion of sand washing technology and its capabilities is presented below.

4.4.2 Additional Technologies

Several methods other than zero discharge via land disposal 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, thermal treatment and air flotation. Most of the sources consulted did not provide data or cleaning efficiencies for the treatment of produced sand.

The only technology for which performance data are available is sand washing with detergents. Data submitted from an industry supported study for the offshore subcategory demonstrate the variability of oil content in washed sand. The oil content of washed produced sand in the study ranged from 0.99 to 4.6 percent by weight.[51] Data submitted by the industry regarding sand washing technology performance at offshore sites demonstrates that even in the case of a sand washing system that generates sand capable of meeting a no free oil limitation, residual liquids and solids (by-products from washing) remain which are unable to meet the no free oil limitation and must be disposed in a matter other than surface discharge.[52]

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.[53] 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.[53] 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.[54]

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 and therefore the addition of extra platform space would be required. 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 offsite for disposal. Since sand washing is designed to only reduce the oil content, produced sand that contains certain levels of Naturally Occurring Radioactive Material (NORM) must be transported to shore for disposal depending on state requirements. In addition, sand washing can generate additional wastes, such as oily solids and oily water, which require further treatment and disposal.

5.0 DOMESTIC WASTES

5.1 DOMESTIC WASTE 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.

5.2 DOMESTIC WASTE 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.[36,55] For drilling rigs, rather than require flow measurement, the State of Louisiana requires operators to report the estimated domestic waste volume as equal to 0.7 bbs/day (30 gal/day) per person occupying the rig.[26] The 1993 Coastal Questionnaire statistics estimate that 76 percent of production facilities discharge domestic/sanitary wastes with an average volume of 2,049 bpy (282 bpd).[5] 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 IX-22 and IX-23 summarize the volume and characteristics of domestic wastes for offshore platforms which would reflect domestic waste in Cook Inlet.

5.3 DOMESTIC WASTE 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 and State permits prohibit discharges of foam (as no visible foam). Where existing discharges may be experiencing discharges of foam, measures taken to remediate the situation can include the relocation of the discharge to a standpipe with a subsurface discharge location and careful selection and use of detergents.

TABLE IX-22

TYPICAL UNTREATED COMBINED SANITARY AND DOMESTIC WASTES FROM OFFSHORE FACILITIES[56]

Number of Persons	Flow (gal/day)	BOD (mg/l)		Suspended Solids (mg/l)		Total Coliforms (x 10)
		Average	Range	Average	Range	
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 IX-23
TYPICAL OFFSHORE SANITARY AND DOMESTIC WASTE CHARACTERISTICS[57]

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

5.3.1 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., in the BCT and NSPS limitations on domestic waste.

EPA compiled U.S. and international regulations governing the discharge of domestic wastes into ocean waters from ships and fixed or floating platforms. Although these Coast Guard regulations are primarily intended for offshore and international waters, EPA Region VI has adopted them as part of the domestic wastes limitations in the General Permit for coastal drilling operations (58 FR 49126).

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 IX-24 summarizes the garbage discharge restrictions from fixed or floating platforms.

In summary, 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 the exception that food wastes may be discharged from fixed and floating platforms located beyond 12 nautical miles from the nearest land (33 CFR 151.75).

6.0 SANITARY WASTES

6.1 SANITARY WASTE 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

TABLE IX-24
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.

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.[58] Monthly average sanitary waste flow from Gulf Coast platforms was 35 gallons per day based on discharge monitoring reports.[59] For drilling rigs, rather than require flow measurement, the State of Louisiana requires operators to report the estimated sanitary waste volume as equal to 0.00006 MGD/day (60 gal/day) per person occupying the rig.[26] The EPA 1993 Coastal Oil and Gas Questionnaire statistics estimate that 76 percent of production facilities discharge domestic/sanitary wastes with an average volume of 2,049 bpy (282 bpd).[5]

6.2 SANITARY WASTE CONTROL AND TREATMENT TECHNOLOGIES

There are two alternatives to handling of sanitary wastes from coastal 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 wastestream.

7.0 MINOR DISCHARGES

The term "minor" discharges is used to describe all point sources originating from coastal 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) is used as hydraulic fluid in blowout preventer (BOP) stacks during drilling of a well. The blowout preventer 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. Such discharges are limited to deep water operations such as in Cook Inlet. BOP fluid released from above water applications would be captured as deck drainage and treated and disposed accordingly.

7.2 DESALINATION UNIT DISCHARGE

This is the residual high-concentration brine discharged 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 surface as a separate waste stream.

7.3 FIRE CONTROL SYSTEM TEST WATER

The local water source which may be treated with a biocide, is used as test water for the fire control system on platforms and other facilities. This test water is discharged directly 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 at production and drilling operations. Biocides can be used to control biofouling in heat exchanger units. Non-contact cooling waters are kept separately and discharged directly to the surface.

7.5 Ballast and Storage Displacement Water

Two types of ballast water are found in production and drilling operations: tanker and platform ballast. Tanker ballast water can be either salt/brackish 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.

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 surface.

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 in Cook Inlet 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 Cartridge Filters

Filtration using cartridge filters is commonly used at coastal facilities as a pretreatment step prior to injection to prevent plugging of the injection formation and was included as a pretreatment in the subsurface injection option for produced water in the Gulf of Mexico region. Cartridge filters are not reusable and must be disposed as solid waste when replaced. The waste filters are typically disposed in sanitary landfills.

7.16 Natural Gas Glycol Dehydration Wastes

A common step in processing natural gas is dehydration using a desiccant such as triethylene glycol. In this process natural gas is brought into contact with a glycol stream which has an affinity for and adsorbs water vapor. The glycol is then passed through a reboiler where the water is distilled out of the solution. This vaporized water is then condensed into a liquid waste stream. This waste stream may be returned to the produced water treatment and disposal system or it may be surface discharged. Sometimes impurities will build up in the glycol solution requiring that it be replaced. Spent glycol can be regenerated onsite through distillation or it is hauled offsite for regeneration or disposal.

7.17 Minor Wastes Volumes and Characteristics

Information concerning the characteristics, discharge volumes, and the frequency of discharge of these minor waste streams is limited. Table IX-25 provides a range of discharge volumes for the minor waste streams that were identified for the offshore category. Data concerning the characteristics and volumes of test fluids, diatomaceous earth filter media, bulk transfer operations, and painting operations are not available.

TABLE IX-25
MINOR WASTE DISCHARGE VOLUMES[15]

Waste	Discharge Volume
BOP fluid	10 - 500 gal/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
Cartridge filters	1,300 - 2,500 cartridges/year
Glycol dehydration condensate	Unknown

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SECTION X

COST AND POLLUTANT LOADING DETERMINATION OF DRILLING FLUIDS AND DRILL CUTTINGS

1.0 INTRODUCTION

This section presents incremental costs and pollutant reductions for the proposed regulatory options for drilling fluids and drill cuttings. Incremental compliance costs beyond BPT were developed for each disposal/control option for Cook Inlet, Alaska only. Compliance costs were not developed for the other coastal regions where oil and gas activity exists, because, as discussed in earlier sections of this report, discharges of drilling fluids and drill cuttings do not occur in these areas.

2.0 OPTIONS CONSIDERED AND TOTAL COSTS

Three disposal options were considered for control and treatment of drilling fluids and drill cuttings for this rule. These options are:

Option 1: Zero discharge for all areas except Cook Inlet where discharge limitations require toxicity of no less than 30,000 ppm (SPP), no discharge of free oil and diesel oil and no more than 1 mg/l mercury and 3 mg/l cadmium in the stock barite (these limitations are reflective of current practice in Cook Inlet and are similar to the offshore limitations).

Option 2: Zero discharge for all areas except Cook Inlet where discharge limitations would be the same as Option 1, except toxicity would be set at a limitation between 100,000 ppm (SPP) and 1 million ppm (SPP).

Option 3: Zero discharge for all areas.

Costs for any of the options are applicable only to Cook Inlet operators (since they are the only coastal operators currently not meeting zero discharge). Since Option 1 is reflective of current practice in Cook Inlet, no costs are attributed to this option. Thus, costs and pollutant removals that are incremental to current practice were only determined for Option 2 and 3. Incremental costs and loadings above BPT-level limitations were determined for Options 1 and 2 as part the BCT cost test analysis for those options (see Section 6.0).

Option 1 consists of four basic requirements: (1) a toxicity limitation set at 30,000 ppm in the suspended particulate phase; (2) a prohibition on the discharge of diesel oil; (3) no discharge of free oil based on the static sheen test; and (4) limitations for cadmium and mercury set in the stock barite at 3 mg/kg and 1 mg/kg, respectively. The 100,000 to 1,000,000 ppm toxicity limitation in Option 2 would replace the 30,000 ppm requirement in Option 1. Options 1 and 2 apply to the drill cuttings as well as drilling fluids since drilling fluid adheres to cuttings and is discharged along with the drill cuttings.[1] The same pollutants found in drilling fluids are thus found on the wet drill cuttings.

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.[2] The toxicity limitation would apply to any periodic blowdown of drilling fluid as well as to bulk discharges of drilling fluid systems and cuttings. The term "drilling fluid systems" refers to particular types of drilling fluids 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 either land disposal or injection of the spent drilling fluid system to comply with the effluent limitations. 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 and cuttings at any time.

For Options 1 and 2, diesel oil and free oil would serve as "indicators" of toxic pollutants, and thus these discharges would be 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 these limitations. Diesel oil would 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; (2) transport to shore for recovery of the oil, reconditioning of the drilling fluid for reuse, and land disposal of the drill cuttings; or (3) grind and inject the drilling wastes. 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 would 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 would be regulated to control the metals content of the barite component of any drilling fluid discharges. Compliance with this requirement would involve use of barite from sources that either do not contain these metals or contain the metals at levels below the limitation.

Option 2 would require all operators to meet the same zero discharge limitation for the drilling fluids and cuttings in all areas except for Cook Inlet. In Cook Inlet, the drilling fluids and cuttings discharges would be required to meet the same limitations as in Option 1 except that a more stringent toxicity limitation would be imposed. Instead of meeting a toxicity limitation of 30,000 ppm (SPP), a toxicity limitation between 100,000 ppm (SPP) and 1 million ppm (SPP) would be met.

The toxicity limitation range of between 100,000 ppm (SPP) and one million ppm (SPP) reflects the range of toxicity measurements resulting from EPA's evaluation of the current practice for drilling in Cook Inlet. As discussed previously in section V, an attempt was made in this evaluation to determine the volumes of drilling wastes being discharged and their respective toxicity levels. Because of the lack of identified discharge volumes for some of the toxicity test results, this determination could not be completed. Using the 83 percent of drilling wastes which reflects the fraction of test results less toxic than 100,000 ppm (SPP), and coincidentally also reflects the fraction of identified volumes less toxic than one million ppm (SPP), costs and discharge loadings were developed for this option. (The method used to derive this range is separate and distinct from the statistical methodologies generally used by EPA in effluent guidelines regulations to derive 30-day average and daily maximum limitations calculated from the 95th and 99th percentiles, respectively.) However, due to the above discussed limitations with the data base, EPA is currently only able to estimate an achievable toxicity limit in the range of 100,000 ppm (SPP) to one million ppm (SPP). EPA is continuing to evaluate toxicity test results and volumes and any other data for drilling fluids used and discharged in Cook Inlet in an effort to derive a more specific limitation and resulting revisions of costs and loadings. A supplemental notice presenting the data and revised results and soliciting comment may be necessary prior to promulgation.

For Option 2, the 100,000 to 1 million ppm (SPP) toxicity limitation would be based on a combination of recycling and reuse, onshore disposal or grinding and injection where the limit is not attained, and product substitution to attain the limit. Option 3 would prohibit the discharge of drilling fluids and cuttings from all coastal oil and gas drilling operations. This option utilizes grinding and injection and onshore disposal as a basis for complying with zero discharge of drilling fluids and cuttings. The technology option alternatives for Cook Inlet have been developed taking into consideration that Cook Inlet operations are unique to the industry due to a combination of climate, transportation logistics, and structural and space limitations.

Table X-1 presents the estimated total costs and annual costs attributed to each of the three options presented above. The derivation of these costs are described in detail in the remainder of this section.

3.0 OVERVIEW OF METHODOLOGY

To evaluate the incremental compliance costs and pollutant removals associated with regulatory options considered in this rulemaking, the following information was used:

TABLE X-1

COST OF DRILLING FLUIDS AND CUTTINGS CONTROL OPTIONS

Option	Total Costs*	Annual Cost
Option 1 Zero discharge for all areas except Cook Inlet where discharge limitations require toxicity of no less than 30,000 ppm (SPP), no discharge of free oil and diesel oil and no more than 1 mg/l mercury and 3 mg/l cadmium in the stock barite.	$0	$0
Option 2 Zero discharge for all areas except for Cook Inlet where discharge limitations would be the same as Option 1, except toxicity would be set to meet a limitation between 100,000 ppm (SPP) and 1 million ppm (SPP).	$6,991,463	$1,370,685
Option 3 Zero Discharge for all areas.	$23,380,320	$3,889,386

* All costs were calculated based on the drilling activity plans or schedules as provided by the industry which actually covered a 7-year period, from 1996 through 2002.

- Number of new coastal wells that will be drilled and number of existing coastal wells that will be recompleted in the 7-year period following promulgation of this rule in the Cook Inlet region of Alaska;
- Typical volumes of drilling wastes which will be generated from drilling a new well or a recompletion;
- Characteristics of the drilling waste including additives, volumes and composition; and
- Drilling waste disposal equipment, transportation, methods, and costs.

A set of detailed spreadsheets was developed for predicting industry-wide compliance costs and pollutant removals for each regulatory option considered. All costs are for BAT or BCT, and no costs will be attributed to NSPS since there are no plans for construction of any new development wells from new platforms in Cook Inlet. (All well drilling will be from existing platforms and is therefore defined as existing sources.) In characterizing the coastal Alaska drilling industry, EPA used the drilling activity plans or schedules as provided by the industry which actually covered only a 7-year period, from 1996 through 2002, because no information on drilling beyond this time was available.[3] The typical volumes

of drilling fluids and cuttings generated during a drilling event were estimated based on information provided by the industry in the 1993 Coastal Oil and Gas Industry Questionnaires (see Worksheet 1 in Appendix X-1). The disposal costs were estimated based on the cost and operation information provided by the industry (see Worksheets 2 to 5 and 2T to 5T in Appendix X-1).

EPA also considered the logistical difficulties of transporting drilling wastes in the Cook Inlet as part of its costing analysis of the options. To achieve zero discharge, certain platforms would transport drill wastes to a transfer and storage station on the eastern side of Cook Inlet by supply boat where it would be transferred to barges for transport to an existing landfill facility on the west side of the Inlet. During the summer months, during ice conditions, the wastes would be stored at the transfer station until they could be transported.

3.1 CURRENT PRACTICE

BPT effluent limitations for coastal drilling fluids and cuttings prohibit the discharge of free oil (using the visual sheen test). However, because of either EPA general permits, state requirements, or operational preference, no drilling fluids and cuttings discharges are occurring in the North Slope, the Gulf coast states, or California. The only coastal operators discharging drilling fluids and cuttings are located in Cook Inlet. In Cook Inlet, neither diesel nor mineral-oil-based drilling fluids or resultant cuttings may be discharged to surface waters because they have been shown to cause a visible sheen upon the receiving waters. Compliance with the BPT limitations may be achieved either by product substitution (substituting a water-based fluid for an oil-based fluid), recycle and/or reuse of the drilling fluid, grinding and injection, or by onshore disposal of the drilling fluids and cuttings at an approved facility.

NPDES permits issued by EPA for Cook Inlet drilling operations have also included BAT limitations based on "best professional judgement" (BPJ). The permit requirements allow discharges of drilling fluids and drill cuttings provided certain limitations are met including a prohibition on the discharges of free oil and diesel oil, as well as limitations on mercury, cadmium, toxicity and oil content (see Section III for a summary of the permits). Operators may employ any number of the following waste management practices to meet those permit limitations:

- Product substitution - to meet prohibitions on free oil and diesel oil discharges, as well as the toxicity and/or clean barite limitations,

- Onshore treatment and/or disposal of drilling fluids and drill cuttings that do not meet the toxicity and clean barite limitations,
- Waste minimization - enhanced solids control to reduce the overall volume of drilling fluids and drill cuttings,
- Conservation and recycling/reuse of drilling fluids, and
- Grinding and injection.

4.0 BASIS FOR ANALYSIS AND ASSUMPTIONS

The following sections describe the assumptions and input data used to develop compliance costs and pollutant reductions for drilling wastes in the Cook Inlet region. These sections include the following topics:

- **Drilling Activity**: The volumes of generated drilling waste were calculated based on the number of drilling events and the average volume of waste generated from each drilling event. The generated drilling waste volumes were used in both compliance cost and pollutant loadings analysis.

- **Drilling Waste Volumes**: The drilling waste volumes were the major component of the compliance cost and pollutant loading calculations. The compliance costs and pollutant loadings were calculated from drilling waste volumes and the unit disposal costs, and pollutant concentrations in drilling waste.

- **Drilling Fluid Characteristics**: The drilling fluid characteristics such as density, percent solids, density of dry solids, and concentration of barite were used for the purpose of calculating the pollutant loadings.

- **Drill Cuttings Characteristics**: The density of drill cuttings was used to calculate the total suspended solids (TSS) loading from the spent drill cuttings.

- **Mineral Oil Content**: The major source of organic pollutants in the drilling waste was assumed to be the mineral oil pills used to free stuck pipe. The average reported usage of mineral oil pills and concentration of organic pollutants present in the mineral oil were the bases for calculating the organic pollutants loadings.

- **Barite Characteristics**: The major source of metals in the drilling wastes was assumed to be barite. The amount and characteristics of the raw barite used will determine the concentrations of metals in the drilling fluids. Stock barite that meets regulated metals limitations is referred to as "clean barite." For the purpose of calculating the metals concentrations in drilling fluids, the metals concentrations of clean barite was used.

- **Toxicity Test Failure Rates:** The volume of drilling waste brought to shore for disposal is a function of the compliance failure rates. In order to calculate the compliance costs and pollutant loadings of Option 1 (30,000 ppm toxicity limit) and Option 2 (1,000,000

ppm toxicity limit), the estimated toxicity test failure rates for these limitations were used.

- **Grinding and Injection**: For the Cook Inlet operators for whom landfilling of wastes is not economical to meet the zero discharge requirement of Option 3, EPA investigated the option to grind and inject their drilling waste.

- **Transportation and Onshore Disposal Costs:** Local landfill disposal of the generated drilling waste in Cook Inlet requires transportation to a transfer station or a temporary onshore storage facility via V-hulled supply boats because of sea ice conditions in winter time and highly fluctuating tides in summer. Barges and/or trucks are used to transport the generated drilling waste to a landfill disposal facility from the transfer station. The unit cost of onshore disposal of the generated drilling waste was calculated for each operator based on information obtained from the industry. These unit disposal costs were used to calculate the total compliance costs for Options 2 and 3 based.

Sources of information and data used to develop compliance costs and pollutant reductions include: (1) the Development Document for offshore oil and gas regulations[2], (2) the 1993 Coastal Oil and Gas Questionnaires, (3) correspondence with operators in Cook Inlet, (4) communications with vendors and suppliers serving operation in Cook Inlet, and (5) EPA trip reports. Details of much of the input data are presented in Section VII. The following information is specific to this costing effort.

4.1 Drilling Activity

As stated in Section 2.0, the Agency based the incremental cost analysis and pollutant removal estimations on the total volume of drilling waste generated in Cook Inlet for the 7-year period following the promulgation of this rule from 1996 through 2002. The total volume of muds and cuttings generated was estimated from the projection of the number of wells to be drilled by the industry and the average volume of waste generated from each well. Table X-2 presents the projected drilling activities of the operators in Cook Inlet based on information provided by the industry. Due to the confidential nature of some of the information provided by the industry, a detailed discussion of the estimates listed in Table X-2 is provided in a supporting document.[3]

Out of the five Cook Inlet operators, information obtained by EPA in 1993 indicated that one of them had no plans to drill in the Inlet. Recent (1995) information from an additional Cook Inlet operator relates that this operator also no longer has plans to drill in the Inlet.[3] EPA conservatively estimated that this operator ("C") would have drilled 6 new wells (out of a total of 36 for all of the Cook Inlet operators) in the next 7 years. Due to the fact that this is very recent information, the cost and economic

TABLE X-2
SUMMARY SCHEDULE OF DRILLING ACTIVITIES BY OPERATORS IN COOK INLET, ALASKA FOR 7 YEARS AFTER PROMULGATION[3]

Operator*	Number of New Wells to be Drilled	Number of Existing Wells to be Recompleted
A	3	1
B	27	18
C	6	0

* Operator identities are confidential.[3] Operator B is actually a combination of two companies, but are operated by one.

analysis was performed assuming only one operator, instead of two operators, will not be drilling. However, retaining the six drillings of Operator "C" in the analysis will not only provide a conservative estimate of the costs and economic impacts, but may serve to cover future changes in oil and gas activity should decisions be made to resume drilling.

4.2 Drilling Waste Volumes

EPA estimates that the total amount of drilling fluids and cuttings annually generated from the drilling activities listed above is 79,776 barrels per year. The volumes of drilling fluid and drill cuttings generated per drilling event, including new wells and recompletions, were calculated based on the drilling schedules in Table X-2, and the muds and cuttings generation rates for three well depth intervals as reported by the industry in the 1993 Oil and Gas Questionnaires. Details of calculations and assumptions used to determine waste volumes are provided in Appendix X-1. The methodology used in determining the typical well depth and the total drill waste generated per drilling event are presented in the following paragraphs.

The methodology used for estimating the industry-wide volume of drilling fluids and drill cuttings discharged is based on the volumes generated from production wells drilled in Cook Inlet. Drilling data from the 1993 Questionnaires for seven wells were entered in a spreadsheet and the average depths and volumes of waste generated were calculated. All wells considered in this estimation were drilled in three

intervals to an average total depth of 11,765 feet. The volume of drilling waste (drilling muds and cuttings) generated from an average 11,765-foot well was estimated to be 14,354 barrels with an average dry cuttings content of 19 percent by volume (Appendix X-1). Since no information was available on the volumes of drilling waste generated during recompletion of existing wells, EPA assumed that the volume of muds and cuttings generated during an average recompletion is equal to the average volume of muds and cuttings generated during the last drilling interval of a new well. This volume was estimated to be 2,194 barrels and was assumed to contain 19 percent dry cuttings by volume (Appendix X-1). This volume is a conservative estimate when compared to the volumes estimated for recompletions in the Gulf of Mexico: 1,803 barrels of fluid and 72 barrels of cuttings per job.[4]

The estimated drilling waste generation rate and the percent dry cuttings were used to estimate the total volumes of waste fluids and cuttings generated for each operator. The estimated total industry-wide volume of fluids and cuttings generated is the sum of all volumes estimated for each operator. An industry source stated that currently, the volume of non-complying drilling waste is generally less than 1 percent of the total generated waste volume.[5] Therefore, EPA estimates that one percent of all generated drilling waste in Cook Inlet is currently not meeting the existing permit limitations in this region and therefore cannot be discharged.[5] Since all disposal costs are directly proportional to the amount of fluids and cuttings that are currently generated, all estimated total volumes were reduced by one percent (1%) to reflect current practice. Thus, the amount of drilling fluids and cuttings discharged is estimated to be 1% less than the ambient generated. Based on this information, EPA's estimates are that approximately 78,978 bbls per year (or a total of 552,846 over the next seven years) are being discharged in Cook Inlet.

4.3 DRILLING FLUID CHARACTERISTICS

Since the drilling fluid characteristics change as drilling proceeds to greater depths, an average mud density was assumed for the purposes of determining the pollutant loadings. Based on the information provided by the industry in the 1993 Coastal Oil and Gas Questionnaire and information obtained through sampling trips, EPA assumed a 10 pound per gallon mud with 11 percent solids by volume to have the average characteristics (density) of the mud system used over the entire drilling project.[6] Using the same bases of information, the density of dry solids and concentration of barite in this mud were estimated to be 1,025 pounds per gallon and 24 pounds per gallon, respectively.[7] The drilling fluid characteristics are also discussed in Section VII of this document.

4.4 DRILL CUTTINGS CHARACTERISTICS

In order to calculate the total suspended solids (TSS) loading due to spent drill cuttings, the density of drill cuttings was estimated. Based on a geological stratigraphic profile provided by the industry, drill cuttings were estimated to have a density of 980 pounds per barrel on a dry weight basis.[8] For the purpose of the pollutant loading analysis for this rule, the volume of dry cuttings was also estimated based on 19 percent of total volume of drilling wastes.[9] Since dry cuttings are generally comprised of inert material, no hydrocarbons or metals were assumed to be present in the dry drill cuttings. Drill cuttings characteristics are also discussed in Section VII of this document.

4.5 MINERAL OIL CONTENT

Based on information obtained from the 1993 Oil and Gas Questionnaires, EPA assumed a mineral oil content of 0.02 percent by volume in the entire volume of drilling waste generated from drilling operations in Cook Inlet.[10] Since there are no significant sources of organic pollutants in the drilling waste other than any oil based lubricant added to the drilling fluid system, it is assumed that the mineral oil is the only source of organic pollutants in the spend drilling fluid and drill cuttings. Table X-3 presents the organic constituents in the mineral oil used to calculate the pollutant loadings for this rulemaking. The concentrations in Table X-3 are averages of concentrations for three types of mineral oil presented in the Offshore Development Document.[2]

4.6 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 and thus, provide EPA with the bases to determine pollutant reductions for each technology option. The concentrations of cadmium and mercury are directly related to the concentrations of other priority pollutants of concern in barite.[11] The current individual NPDES permits in Cook Inlet have limitations on the concentrations of cadmium and mercury in the raw (or stock) barite. Stock barite that meets regulated metals limitations is referred to as "clean" barite. For the purposes of calculating the BAT metals concentrations in drilling fluids, the metals concentrations of clean barite was used.

The mean metals concentrations for "clean" barite are presented in Table X-4. The metals concentrations represent averages of data from *Region 10 Discharge Monitoring Report Data*.[11] The

TABLE X-3

ORGANIC CONSTITUENTS IN MINERAL OIL
(mg/ml, unless noted otherwise)

Organic Constituent	Concentration (mg/ml)
Benzene	ND
Ethylbenzene	ND
Naphthalene	0.05
Fluorene	0.08
Phenanthrene	0.12
Phenol (ug/l)	ND
Alkylated benzenes (a)	30.0
Alkylated naphthalene (b)	0.49
Alkylated fluorenes (b)	1.74
Alkylated phenanthrenes (b)	0.14
Alkylated phenols (c)	ND
Total biphenyls (b)	1.94
Total dibenzothiophenes (ug/g)	370

Notes: The above data are averages of data presented in Table VII-9 of the 1993 Offshore Development Document for three types of mineral oil.[2] Averages include only detected values.
ND = Not Detected for all three types
(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

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 *15 Rig Study* from the Gulf of Mexico was incorporated.[11] The barium concentration reported in Table X-4 was calculated from the total pounds of barite in the drilling fluid.[7] 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.[2] For the purposes of calculating the pollutant loadings for the BAT options, use of clean barite was assumed for drilling operations in Cook Inlet, Alaska.

TABLE X-4

METALS CONCENTRATIONS IN BARITE

Metal	"Clean" Barite Concentration (mg/kg)
Cadmium	1.1[a]
Mercury	0.1[a]
Aluminum	9,069.9[b]
Antimony	5.7[b]
Arsenic	7.1[a]
Barium	33,000.0[7]
Beryllium	0.7[b]
Chromium	240.0[a]
Copper	18.7[a]
Iron	15,344.3[b]
Lead	35.1[a]
Nickel	13.5[a]
Selenium	1.1[b]
Silver	0.7[b]
Thallium	1.2[b]
Tin	14.6[b]
Titanium	87.5[b]
Zinc	200.5[b]

[a] Region 10 DMR Data[11]
[b] 15 Rig Study[11]

4.7 TOXICITY TEST FAILURE RATES

The volumes of drilling wastes that do not meet discharge limitations were calculated according to each option considered. EPA assumed that all oil-based drilling fluids would fail the sheen test.

Based on the information obtained from the industry, approximately one percent of drilling waste generated during 1993 failed the current limitations which include the 30,000 toxicity limitation.[5] Thus, discharges resulting from Option 1 were estimated by calculating the total volume of drilling wastes generated, and assuming one percent of that volume is not discharged while the remaining 99 percent is discharged.

For Option 2, statistical analysis of toxicity data from Cook Inlet drilling fluids showed that "approximately 83 percent of the volume of known drilling fluid discharges to Cook Inlet are associated with toxicity measurements equal to 1,000,000 ppm".[4] This result indicates that 17 percent of the drilling fluids tested for discharge would fail a 1 million ppm toxicity limitation and thus would either be sent onshore for disposal, or ground and injected.

4.8 GRINDING AND INJECTION

To meet the zero discharge requirement of Option 3, those Cook Inlet operators for whom landfilling of wastes is not economical might elect to grind and inject their drilling waste. Disposal of drilling wastes by injection requires: (1) installation of processing equipment to grind the solids into a slurry liquid with fine particles; (2) installation of injection equipment for delivery of the processed wastes into a subsurface formation; and (3) installation of injection wells to allow injection into suitable subsurface formations.

Because of limited space available on production or drilling platforms, EPA assumed that all platforms in question require retrofitting for installation of processing and injection equipment. According to industry, operators with multiple platforms do not need to purchase or lease injection equipment for each platform since such equipment could be shared between platforms.[12]

Processing and injection equipment for use on platforms can be constructed in package units in such a way that the entire unit could be transported and placed on a platform when needed, provided that adequate space is available on that platform.

Operators in Cook Inlet have the option of either purchasing or leasing the processing and injection equipment. EPA evaluated both the costs of leasing and purchasing of these equipment for the purpose of compliance cost calculations. According to the industry sources, the unit cost of purchasing a processing and injection equipment is approximately $1,000,000 and the unit rental cost of the same

equipment is approximately $1,400 per day.[3] The total equipment purchase and rental costs for each operator were calculated and presented in Worksheets 4 and 4T in Appendix X-1. The calculated total purchasing costs of grinding and injection equipment were greater than total rental costs for all operators included in this compliance cost calculations. However, EPA conservatively assumed the higher purchasing costs for all operators except Operator A, for which the lower rental costs were used. The lower rental cost was used for Operator A since this operator currently grinds and injects its spent drilling waste using rented grinding and injection equipment.[3]

Injection of processed drilling waste also requires access to a suitable subsurface formation. Such access can be facilitated through installation of injection wells (i.e., dedicated injection wells) or by leaving the annulus of the wells being drilled open to allow annular injection. According to industry, a suitable formation in Cook Inlet can be found at approximately 4,000 feet.[3] Thus, EPA assumed that dedicated injection wells drilled to that depth would be adequate for injection of drilling waste.

Injection of drilling waste through the annulus of wells being drilled can substantially reduce the costs of injection by eliminating the need to install dedicated injection wells. However, EPA conservatively assessed the costs of grinding and injection through the use of dedicated injection wells. The total assessed costs of grinding and injection of generated drilling waste were $2,405,573, $45,834,740, and $4,486,346 for Operators A, B, and C, respectively (see Worksheet 4 in Appendix X-1). However, the use of this disposal method was found to be economical only for Operators A and C (see Worksheet 5 in Appendix X-1). These costs are discussed in detail in Section 5.3.

The cost analysis, described later in Section 5.0 (Table X-6) resulted in overall for costs for grinding and injection for all operators in Cook Inlet of $458 per barrel for Option 2 and $95 per barrel for Option 3.

4.9 Transportation and Onshore Disposal Costs of Drilling Wastes

In addition to grinding and injection, EPA has also investigated the feasibility of onshore disposal of generated drilling waste. On-land disposal sites in Alaska are available only to Operator B or two out of the four operators in Cook Inlet (see also Table X-2). Using projected drilling schedules provided by industry, EPA estimated that these two operators would generate approximately 76 percent of the drilling wastes produced by the Cook Inlet Operators over the next 7 years (see Worksheet 2 in Appendix X-1). These two operators jointly operate an oil and gas landfill disposal site on the west side of the Inlet. EPA

has determined that there is sufficient on-land disposal capacity to accept all of the drilling fluids and cuttings generated by these operators at this disposal facility.[3] EPA investigated the logistical difficulties of storing and transporting drilling wastes in the Cook Inlet, due to the extensive tidal fluctuations, strong currents, and ice formation during winter months. However, while these climatological and tidal situations may cause complications, EPA determined that they do not pose insurmountable technical barriers. EPA has taken into consideration supplementary costs incurred by additional winter transportation and storage of drilling wastes in its cost evaluation of this option.

Based on information provided by the industry[3], EPA determined that Operator B would use supply boats to transport generated drilling fluid and drill cuttings to a transfer station and temporary storage facility on the east side of Cook Inlet for transfer into barges during the summer months, or temporary storage during winter months when barge traffic is not possible due to sea ice conditions. For example, the upper Cook Inlet would be covered by solid ice in winter if it were not for large tidal ranges (frequently in excess of 30 feet). Because these large tidal ranges produce very strong currents, moving broken ice is a common occurrence in Cook Inlet.[13] Ice typically covers upper Cook Inlet for about four months during the year and portions of the lower Cook Inlet for about three months during the year.[13] Furthermore, barges available in Cook Inlet are not constructed to operate in sea ice conditions. Therefore, during ice conditions, only V-hulled vessels can be used to transport drilling wastes. Because of tidal fluctuations sometimes in excess of 30 feet in summer and ice conditions in winter, V-hulled supply vessels rather than barges are used for transporting supplies and wastes to and from platforms. Therefore, supply boats are used by this operator during the summer and winter months to transport the drilling waste to the transfer station on the east side of the Cook Inlet where the waste materials are transferred onto barges for transportation to the west side landfill facility. Barges are used to transport wastes to the west side of Cook Inlet because during low tide the water depth prohibits access by V-hulled vessels.[14]

EPA determined that since no docking facility is available on the west side of the inlet, the offloading of barges is accomplished by building earthen ramps onto the beach to provide access to the barge. Barges are then maneuvered to the earthen ramps during the high tide. When the tide recedes, the barges are beached near the ramps and unloading resumes.

An onshore disposal cost of $39 per barrel was calculated for Operator B. This unit cost takes into account the costs of all transportation, purchasing waste containers, temporary storage, and landfill

gate fees. Detailed calculations of the $39 per barrel disposal cost are presented in Appendix X-2. This unit cost was calculated based on the following assumptions:

- 8-barrel fluid/cuttings boxes (4 feet x 4 feet x 4 feet) are used for transporting the drilling waste with a purchase cost of $125 per box.[3,14]
- Supply boats are used to transport the drilling waste to a temporary onshore storage facility on the east side of the inlet at the rate of $4,000 per day per boat including loading and unloading costs.[15]
- Each boat will have 130 feet by 28 feet deck space or a capacity of 227 of 8-barrel boxes arranged on deck in one layer.[14,15]
- Transportation for a supply boat load of drilling waste to the temporary storage area will include 1 day boat trip from platform to onshore docking area including loading boxes on deck and 1 day unloading boxes and transportation to temporary storage area.[14]
- Trucks are used to transport fluid/cuttings to the temporary onshore storage area at the rate of $300 per load where each load could include 12 boxes.[3]
- Barges are used for transportation of drilling waste from the east Cook Inlet docking area to the existing landfill facility on the west side of the inlet at the rate of $6,000 per day per barge, with the capacity of 340 boxes.[3,14,15,16]
- Transportation from temporary storage to west side Cook Inlet landfill will include 1 day from storage area to docking facility and loading onto barges.[14]
- Trucks are used to transport the drilling waste from barges to the landfill area.[3]
- Transportation of one barge load of waste from east side docking facility to west side landfill will include 1 day barge trip to west side unloading shore area and one day unloading boxes and transportation to the landfill.[14]
- Onshore disposal cost (gate fee) is $14 per barrel.[26]
- Storage at the temporary storage facility costs $663,418 (at a rate of $0.10 per square foot per month for a total of 42 months and $157,957 per square foot of storage space) (see Appendix X-2).

No on-land oil and gas waste disposal facilities are available in Alaska to the other Cook Inlet operators. EPA investigated the possibility of disposing of drilling wastes at another on-land oil and gas waste disposal site available to Cook Inlet operators located in Idaho. This disposal site was identified in responses to the 1993 Oil and Gas Questionnaires.[9] Depending on the volume of wastes, it may be more economical to dispose of smaller volumes of wastes in the Idaho landfill rather than install injection wells. To be conservative, EPA chose the more expensive grinding and injection for the disposal of the

drill wastes to comply with a zero discharge all option (Option 3), and determined this to be economically achievable for these two operators. However, disposal of the lesser volumes of drilling wastes, those not meeting the toxicity at all limitations, under Option 2, would be shipped to the Idaho site.

For operators other than Operator B, a unit disposal cost of $203 per barrel was assumed. This value was reported by the industry in the 1993 Questionnaires, and includes transportation of the generated waste to the state of Idaho for disposal.[9]

5.0 COMPLIANCE COSTS AND POLLUTANT REMOVALS

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 or grinding and injection.
- Reduction of pollutants discharged to surface waters.

Table X-5 presents a summary of the drilling waste compliance costs and pollutant removals for Options 2 and 3.

Worksheets 1 through 5 and 1T through 5T, located in Appendix X-1, include the lists of all assumptions made and sources of all data and information used in the compliance cost calculations. The remainder of this section discusses the calculation of costs and pollutant loadings for each regulatory option considered.

The BAT incremental compliance costs and pollutant removals were determined based on a volume of muds and cuttings equal to 99 percent of the total volume of drilling waste generated during the 7-year period following promulgation (see Section 2.0 for explanation of this time period). The one percent (1%) reduction in total volume of drilling waste generation represents the volume of waste which does not meet the discharge limitations under the current practices in Cook Inlet.[5] The generated total volume of drilling waste calculated for the 7-year period following promulgation is 558,430 barrels from which 552,846 barrels is discharged under the current practices.

The BAT incremental compliance costs and pollutant removals were evaluated for Options 2 and 3. The BAT incremental compliance cost calculations for the zero discharge and toxicity limitation

TABLE X-5

SUMMARY RESULTS OF DRILLING WASTE COMPLIANCE COSTS AND POLLUTANT REMOVALS FOR COOK INLET

Option 2 Zero discharge for all areas except Cook Inlet where discharge limitations require toxicity of no less than 30,000 ppm (SPP), no discharge of free oil and diesel oil and no more than 1 mg/l mercury and 3 mg/l cadmium in the stock barite.	
Total Cost (Annual)	$1,370,685
Conventional Pollutant Removals (pounds per year)	3,692,669
Priority Pollutant Removals (pounds per year)	642
Non-Conventional Pollutant Removals (pounds per year)	175,584
Total Pollutant Removals (pounds per year)	3,868,896
Percent Reduction From Current Loadings (%)	17
Option 3 Zero Discharge for all Areas	
Total Cost (Annual)	$3,889,386
Conventional Pollutant Removals (pounds per year)	21,703,156
Priority Pollutant Removals (pounds per year)	3,757
Non-Conventional Pollutant Removals (pounds per year)	1,032,105
Total Pollutant Removals (pounds per year)	22,739,018
Percent Reduction From Current Loadings (%)	100

* All costs and pollutants removals were calculated based on the drilling activity plans or schedules as provided by the industry which actually covered a 7-year period, from 1996 through 2002.

options are presented in Worksheets 1 through 5 and 1T through 5T, respectively. The BAT incremental pollutant removals for these two options are presented in Worksheets 10 and 11, respectively (see Appendix X-2). The following paragraphs describe the methodologies and assumptions used in calculating the compliance costs and pollutant removals for each option.

Since all compliance cost estimates are based on the volume of drilling waste generated, the first step in cost evaluation was to estimate the average volume of drilling fluids and cuttings generated from an average drilling event. These averages were determined to be 14,354 barrels and 2,194 barrels for

new wells and completions, respectively. Estimation of drilling waste volumes was discussed earlier in Section 4.2. Detailed calculations are presented in Worksheet 1 or 1T, Appendix X-1.

Worksheet 1 and Worksheet 1T are identical and present the same information, but are duplicated this way because all subsequent compliance cost calculations for both options are linked to the data presented in this worksheet. Worksheet 1 incorporates the drilling information of seven recently drilled wells in the Cook Inlet area. These wells were the only wells recently drilled in Cook Inlet for which complete drilling information was available. The drilling data and cost information were used to calculate the average depth of wells drilled (11,765 feet), the average volume of drilling muds and drill cuttings generated from an average drilling event, average cost of drilling a 4,000-foot injection well ($1,197,173), and the average number of drilling days spent for each drilling event (57 days for a new well and 20 days for a recompletion). Worksheet 1 lists the raw data for three drilling depth intervals as reported by the industry. The average depth of each interval and the average volume of waste generated from each interval were also calculated and presented in this worksheet. The depth and volume of waste generation for an average well was then estimated from the averages calculated for each interval.

Also included in this worksheet are drilling costs from which the cost of drilling a 4,000-foot injection well was estimated. An industry source stated that a depth of 4,000 feet for an injection well is an average depth where a suitable formation can be found for injection of drilling wastes[12] (see also Section 4.8).

Four types of drilling waste disposal methods were considered for estimating the industry-wide compliance costs of each option:

Method 1. Land disposal without the use of high efficiency solids separation units (closed-loop system) to minimize the amount of drilling waste generated.

Method 2. Land disposal with closed-loop system to reduce the volume of drilling waste generated.

Method 3. Subsurface injection of spent drilling waste through dedicated injection wells.

Method 4. A combination of methods (1) through (4).

Worksheets 2 through 5 and 2T through 5T present the calculations and assumptions used to develop waste volumes and disposal costs for each of these four disposal methods.

It is important to note that the total compliance costs reported in Appendix X-1 are for drilling projects expected over the seven years from 1996 through 2002, in which all industry projected drilling schedules occur (these are not annual costs). Table X-6 lists the total compliance cost estimates calculated for each disposal method.

The following subsections provide detailed discussions of each of these disposal methods and their respective worksheets.

5.1 LAND DISPOSAL WITHOUT CLOSED-LOOP SYSTEMS

This disposal method assumes that there will be no high efficiency solids separation units or closed-loop systems installed and the drilling waste generation rates will be similar to the wells recently drilled in Cook Inlet. This disposal method involves possible temporary storage on the platform or onshore and transportation from the platform or onshore temporary storage area to an onshore disposal facility. As discussed earlier in Section 4.9, EPA developed two unit onshore disposal costs for the operators in Cook Inlet. A unit landfill disposal cost of $39 per barrel was calculated for Operator B which has access to an Alaska-based landfill, and a unit cost of $203 per barrel for the other operators which would use an Idaho-based disposal facility, if landfill was the chosen disposal method. These unit disposal costs are the same for Options 2 and 3 (see Worksheet 2 and 2T).

The industry-wide compliance costs were estimated for both Options 2 and 3 based on the volumes of drilling wastes generated and the unit disposal costs indicated above. The volumes of drilling waste were estimated for each option based on the requirements of that option, average volume of waste generated from an average drilling event, and the projected drilling activity schedules.

Worksheets 2 and 2T present the estimated individual and industry-wide incremental compliance costs of Options 3 and 2 by land disposal without closed-loop system, respectively. The total industry-wide compliance costs based on this disposal method was estimated to be $7,291,613 or $78 per barrel of waste for Option 2 and $42,891,839 or $78 per barrel of waste for Option 3. In the analysis that selected the most cost-effective disposal methods for each operator, land disposal without closed-loop systems was selected for all operators under Option 2, and for Operator B under Option 3 (see Section 5.4). While closed-loop systems offer advantages in less make-up fluid requirements and less drilling waste produced, the platform retrofit, equipment and operating costs of these systems made them more costly than non-closed-loop systems for the Cook Inlet platforms.

TABLE X-6

Industry-Wide Compliance Cost Estimates (1992 $)[a]

Disposal Method	Worksheet No. in Appendix X-1	Total Compliance Cost[b]	Cost in $/bbl Waste Disposed	Annual Compliance Cost[c]
Zero-Discharge Option				
Land Disposal Without Closed-Loop	2	$42,891,839	$78	NC[d]
Land Disposal With Closed-Loop	3	$40,158,169	$105	NC[d]
Dedicated Well Injection	4	$52,726,659	$95	NC[d]
Combined Disposal[e]	5	$23,380,320	$42	$3,889,386
100,000-1,000,000 ppm SPP Toxicity Option				
Land Disposal Without Closed-Loop	2T	$6,991,463	$74	NC[d]
Land Disposal With Closed-Loop	3T	$15,594,013	$240	NC[d]
Dedicated Well Injection	4T	$43,008,286	$458	NC[d]
Combined Disposal[f]	5T	$6,991,463	$74	$1,370,685

a Source: Appendix X-1
b Total costs are for all projected drilling from 1996 through 2002
c Source: ERG, November 11, 1994[17]
d Not calculated
e Assumes landfill without closed-loop system for Operator B and dedicated well injection for Operators A and C
f Assumes landfill without closed-loop system for all operators

5.2 LAND DISPOSAL WITH CLOSED-LOOP SYSTEMS

Land disposal with the closed-loop systems method assumes installation of high efficiency solids separation units to minimize the volume of drill waste generated. The components of a closed-loop system considered by EPA include high efficiency shale shakers, mud cleaners, chemically enhanced centrifugation (CEC), waste storage tanks, and transfer equipment. Installation of closed-loop systems reduces the overall landfill and transportation costs but will incur additional costs of retrofitting the platform, purchasing or leasing of high efficiency separation equipment, and operating the equipment.

Installation of closed-loop systems will enable the operator to reuse the same mud for a longer period of time and therefore reduce the need to introduce fresh mud into the system. Data from the 1993 Questionnaires indicate that in Cook Inlet, high efficiency solids separation units on average reduce the volume of spent drilling waste by 69 percent.[18] However, a platform may not have adequate deck space for installation of additional solids separation systems and may require retrofitting. The Agency estimated an average retrofitting cost of $270,000 and assumed that all platforms need retrofitting. This retrofitting cost was estimated based on the need for 450 square feet of additional deck space at the rate of $600 per square foot.[12,19]

Based on information obtained from Gulf of Mexico industry sources, EPA estimated an average cost of $1,900 per day for leasing high efficiency solids separation systems.[19] The estimated $1,900 per day costs include all maintenance costs. However, the Agency added an additional cost of $1,000 per day for any additional operating costs that may be needed in Cook Inlet. The $1,000 per day operating cost was reported by Cook Inlet industry sources for operation of waste processing and injecting equipment.[20] Since a closed-loop system is comparable to a processing and injecting system in terms of labor requirements, the Agency assumed the unit operating cost determined for operation of injection systems as the unit operating cost for operation of closed-loop systems. The total equipment and operating costs of a closed-loop system were calculated from the total number of drilling events for each operator, the average drilling period estimated for each drilling event, the unit equipment cost, and the unit operating cost. The same $39 per barrel and $203 per barrel land disposal unit costs specified for Method 1 were also used for this disposal method.

The industry-wide disposal cost based on this disposal method was estimated to be $15,594,013 or $240 per barrel of waste for Option 2 and $40,158,169 or $105 per barrel of waste for Option 3. These costs are listed in Worksheet 3 and 3T, Appendix X-1. Thus, use of closed-loop technology is not less expensive for existing rigs associated with the Cook Inlet platforms because of retrofit costs.

5.3 Subsurface Injection Through Dedicated Wells

Subsurface injection of drilling waste through a dedicated injection well involves the installation of dedicated injection wells to a suitable underground formation, grinding of the mud and cuttings solids into a slurry liquid with fine particles, and injection of processed waste into the subsurface formation.

The total industry-wide disposal cost for this method includes the costs of dedicated injection wells, platform retrofitting, injection equipment, and injection equipment operation. The unit cost of installing a 4,000-foot injection well was estimated to be $1,197,173 per well in Worksheet 1. For the zero discharge option (Option 3), the number of dedicated wells was estimated for each operator based on the assumption that one injection well is needed for every 4 new drillings[21] and one for every 16 recompletions. The assumption for one injection well for every 16 recompletions was based on the approximate ratio of 4:1 between the estimated volumes of drilling waste generated from a new well and a recompletion which was shown in the 1993 Questionnaire data.[9] For Option 2 however, one injection well was assumed for every 8 new drillings and one well for every 32 recompletions, since only 17 percent of the total volume will be injected under this option.

The cost of retrofitting platforms was assumed to be $750,000 per platform based on information provided by the industry.[3] The Agency assumes that all platforms would need retrofitting. Based on information obtained from the industry, it was further assumed that operators with multiple platforms do not need to install injection equipment at each platform, because injection equipment could be shared as long as space is available at each platform.[3] Based on information provided by the industry, it was assumed that 4 injection units would be adequate for Operator B which operates 12 platforms in Cook Inlet. For the other operators with only one platform, one injection unit was assumed for each platform.

The costs of injection equipment were estimated for both purchasing and leasing of the equipment based on $1,000,000 per system[3] for purchasing or $1,400 per day for leasing.[3] The Agency assumed operators would purchase the injection equipment except where the additional purchasing cost versus the lower leasing cost could not be justified. For example, for Operator A it was assumed that the injection equipment would be leased at the total cost of $267,400 since purchasing the equipment at total cost of $1,000,000 could not be justified. However, the estimated total purchasing cost of $4,000,000 was assumed for Operator B over the estimated $3,150,000 total leasing cost because leasing of processing and injection equipment may not be justified for this operator if the salvage value of the purchased equipment is considered.

Additional costs of operating the injection equipment were also included in total costs for all operators. Operating costs included labor, maintenance, and chemicals used (see Section VII213). For Operators A and C, an additional cost of $1,000 per day was included based on the information obtained from the industry.[3] For Operator B, a much greater unit operating cost of $9,260 per day was estimated

based on the total volume of drilling waste generated for this operator and a unit operating cost of $200 per cubic yard of waste, as reported by the industry.[23]

The total industry-wide costs for Options 2 and 3 using injection through dedicated wells are presented in Worksheets 4T and 4, respectively. The total injection costs for Option 2 were estimated to be $43,008,286 or $458 per barrel of waste and for Option 3, $52,726,695 or $95 per barrel of waste. The estimated unit disposal cost for Option 2 is substantially greater than the unit cost estimated for Option 3 since a relatively much lower volume of drilling waste will be injected for this option at almost the same capital cost as Option 3.

5.4 COMBINED DISPOSAL METHOD

This disposal method compares the estimated disposal costs of the landfill, and dedicated well injection, disposal methods of each operator and selects the most cost-effective method for each operator. The total industry-wide disposal costs are then the sum of the least costly disposal method per operator, per option. The combined method cost estimations are presented in Worksheets 5T and 5 for Options 2 and 3, respectively.

The total industry-wide cost for Option 2 was estimated to be $6,991,463 or $74 per barrel. The disposal methods assumed to generate this cost were landfill without closed-loop system for all operators. Similarly, the total industry-wide cost for Option 3 was estimated to be $23,380,320 or $42 per barrel of waste. The disposal methods assumed to generate this estimated cost were landfill without closed-loop system for Operator B and dedicated well injection for Operators A and C (see Table X-6). Costs for the two operators under Option 3 to dispose of their wastes in the Alaskan landfill average $39/barrel. Costs for the other two operators (one operator has no future plans to drill) to dispose of their wastes by grinding and injection average $53/bbl. A weighted average for disposal of 76 percent of the drilling wastes by Alaskan landfills and 24 percent by grinding and injection equates to $42/bbl. On a per well basis, this amounts to approximately $425,000 and $600,000 for each recompletion and new well drilled, respectively.

As discussed in Section 4.9, it is estimated that Operator B would generate 422,780 bpy or 76 percent of all drilling wastes in Cook Inlet over the seven years following promulgation of this rule (see Appendix X-1). Operators A and C are estimated to generate 44,803 bpy and 85,263 bpy, respectively, or the remaining 24 percent. Thus, for the combined disposal method under Option 2, in which 17

percent of the drilling waste generated must be disposed, Operator B would dispose of 13 percent (76% x 17%) via landfill in Alaska while Operators A and C would collectively dispose of 4 percent (24% x 17%) via landfill in Idaho. Under the combined disposal method of Option 3, in which all wastes must be disposed, 76 percent would be landfilled in Alaska and 24 percent would be injected.

5.5 INCREMENTAL POLLUTANT REMOVALS

The total industry-wide incremental pollutant removals were estimated for Options 2 and 3 based on the total incremental volume and pollutant concentrations in the generated drilling muds and drill cuttings. Table X-7 presents the pollutant loadings resulting from the application of Options 2 and 3. Loadings are the product of the pollutant concentrations and the waste volume discharged following a particular treatment. A shown in Table X-7, the loading resulting from zero-discharge (Options 3) are all 0 barrels per year because no discharge would be allowed. For the toxicity limitation (Options 2), the loadings are based on 83% of the current waste volume being discharged because this is the volume of waste discharged as a result of the toxicity limitation. The pollutant reductions, listed in Table X-8, are the difference between the loadings from current practice and the loadings resulting from each option. Table X-8 presents a summary of the estimated pollutant removals for both options. Detailed calculations for each option are presented in Appendix X-1.

For both options, the pollutant reductions were calculated by multiplying the concentrations of pollutants in currently discharged wastes (Column 2 in both worksheets 10 and 11) by the volume of wastes that would not be discharged according to each option. This volume reduction is the difference between the currently discharged volumes and the volumes discharged after application of each option (Columns 3 and 5 in both Worksheets). Worksheet 10 provides the pollutant reductions for Option 3, the zero-discharge option. The overall reductions for this option (Column 7 of the worksheet) are equal to the total loadings calculated for current discharges (Column 4) because the application of zero discharge essentially removes all pollutants currently being discharged. Worksheet 11 provides the pollutant reductions for Option 2, the 100,000 - 1,000,000 ppm SPP toxicity limitation option. The reductions listed in Column 7 of this worksheet represent 83 percent of the current volumes being discharged, because it has been determined that 17 percent could not meet a toxicity limitation of 100,000 -1,000,000 ppm.

The values in Column 3 of Worksheets 10 and 11, "Amount of Total Drilling Waste Currently Discharged," are presented on page 1 of the worksheets. The value by which heavy metal concentrations

TABLE X-7

DRILLING WASTE POLLUTANT LOADINGS IN COOK INLET

Pollutant	Total Annual Loadings Based on Current Practices[a]	Total Annual Loading Based on Toxicity Limit (Option 2)[b]	Total Annual Loading Based on Zero Discharge (Option 3)[c]
Conventionals			
TSS (Total)	21,699,381	18,010,486	0
Oil Content (Total)	3,775	0	0
Total Conventionals	**21,703,156**	**18,010,486**	**0**
Priority Pollutant Organics			
Naphthalene	0.2	0	0
Fluorene	3.6	0	0
Phenanthrene	0.5	0	0
Total P.P. Organics	**4.3**	**0**	**0**
Priority Pollutant Metals			
Cadmium	7.9	6.5	0
Mercury	0.7	0.6	0
Antimony	40.7	33.8	0
Arsenic	50.7	42.1	0
Beryllium	5.0	4.1	0
Chromium	1,713.8	1,422.4	0
Copper	133.6	710.8	0
Lead	250.6	208.0	0
Nickel	96.4	80.0	0
Selenium	7.9	6.5	0
Silver	7.0	4.1	0
Thallium	8.6	7.1	0
Zinc	1,431.7	1,188.3	0
Total P.P. Metals	**3,752.5**	**3,114.5**	**0**
Non-Conventionals			
Aluminum	64,765.7	53,755.6	0
Barium	856,888.1	711,217.1	0
Iron	109,569.6	90,942.7	0
Tin	104.3	86.5	0
Titanium	624.8	518.6	0
Alkylated benzenes[c]	133.1	0	0
Alkylated naphthalenes[c]	2.2	0	0
Alkylated fluorenes[c]	7.7	0	0
Alkylated phenanthrenes	0.9	0	0
Total biphenyls[c]	8.6	0	0
Total dibenzothiophenes	1,431.7	0	0
Total Non-Conventionals	**1,032,105.1**	**856,520.6**	**0**
Total Loadings	**22,739,017.7**	**18,870,121.6**	**0**

[a] Values are from Column 4 of both Worksheets 10 and 11, divided by 7 years (See Appendix X-3)
[b] Values are from Column 6 of Worksheet 11, divided by 7 years (See Appendix X-3)
[c] Values are from Column 6 of Worksheet 10, divided by 7 years (See Appendix X-3)

TABLE X-8

DRILLING WASTES POLLUTANT LOADINGS IN COOK INLET

Pollutant	Option 2 1 MM ppm SPP Toxicity		Option 3 Zero Discharge	
	Total Cumulative Reductions (lbs)[b]	Annual Reductions (lbs/yr)	Total Cumulative Reductions (lbs)[b]	Annual Reductions (lbs/yr)
Conventionals				
TSS (Total)	25,822,263.7	3,688,894.8	151,895,668.6	21,699,381.2
Oil Content (Total)	26,422.3	3,774.6	26,422.3	3,774.6
Total Conventionals	25,848,686.0	3,692,669.4	151,922,090.9	21,703,155.8
Priority Pollutant Organics				
Naphthalene	1.6	0.2	1.6	0.2
Fluorene	25.0	3.6	25.0	3.6
Phenanthrene	3.7	0.5	3.7	0.5
Total P.P. Organics	30.3	4.3	30.3	4.3
Priority Pollutant Metals				
Cadmium	9.3	1.3	55.5	7.9
Mercury	0.8	0.1	5.0	0.7
Antimony	48.4	6.9	284.9	40.7
Arsenic	60.3	8.6	354.9	50.7
Beryllium	5.9	0.8	35.0	5.0
Chromium	2,039.4	291.3	11,996.4	1,713.8
Copper	158.9	22.7	934.7	133.5
Lead	298.3	42.6	1,754.5	250.6
Nickel	114.7	16.4	674.8	96.4
Selenium	9.3	1.3	55.0	7.9
Silver	5.9	0.8	35.0	5.0
Thallium	10.2	1.5	60.0	8.6
Zinc	1,703.7	243.4	10,022.0	1,431.7
Total P.P. Metals	4,465.1	637.9	26,267.2	3,752.5
Non-Conventionals				
Aluminum	77,071.2	11,010.2	453,360.2	64,765.7
Barium	1,019,696.9	145,671.0	5,998,217.1	856,888.2
Iron	130,387.8	18,626.8	766,987.0	109,569.6
Tin	124.1	17.7	729.8	104.3
Titanium	743.5	106.2	4,373.7	624.8
Alkylated benzenes[c]	931.7	133.1	931.7	133.1
Alkylated naphthalenes[c]	15.3	2.2	15.3	2.2
Alkylated fluorenes[c]	54.0	7.7	54.0	7.7
Alkylated phenanthrenes	6.3	0.9	6.3	0.9
Total biphenyls[c]	60.3	8.6	60.3	8.6
Total dibenzothiophenes	0.2	0.0	0.2	0.0
Total Non-Conventionals	1,229,091.3	175,584.5	7,224,735.6	1,032,105.1
Total Reductions	27,082,272.7	3,868,896.1	159,173,124.0	22,739,017.7
Percent Reduction from Current Practice	17%	17%	100%	100%

[a] Source: Appendix X-1

[b] Total cumulative reductions cover the 7-year period from 1996 through 2002.

[c] These analyte groups contain both priority pollutants and non-conventional pollutants, but were not distinguished in the source document.

are multiplied (50,490,043 lbs) is the dry weight of muds currently discharged. This value is used in Column 3 because the metals concentrations are given on a dry weight basis, and because it is assumed that metal contaminants are associated only with barite in the drilling fluid (see Section 4.6). The value by which organic and total oil concentrations are multiplied (447,805 bbls) is the volume of drilling muds currently discharged. The concentrations of these pollutants are given on a volumetric basis.

Column 5 of Worksheets 10 and 11 presents the percentage of the amounts reported in Column 3 that will be discharged following application of each option. Worksheet 10 shows 0% discharged following the zero-discharge option, and Worksheet 11 shows 83% discharged as a result of the 17% toxicity test failure rate (see Section 4.7).

Page 1 of Worksheets 10 and 11 provides the calculations for the total suspended solids (TSS) values in the cuttings and the muds. The TSS value for the cuttings is equal to the total weight of dry cuttings, calculated from the known volume of cuttings discharged and the density. The TSS value for the drilling muds, referred to as the "total dry weight of muds currently discharged," is the product of the known volume of muds discharged, the percent of dry solids in the mud by volume, and the density. The TSS value for drilling muds is also the value of the dry-basis amount of waste discharged, listed in Column 3 of the worksheets.

6.0 BCT Compliance Costs and Pollutant Removals Development

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 $0.534 per pound ($0.25 per pound in 1976 dollars indexed to 1992 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.

6.2 BPT BASELINE

In order to estimate the incremental costs and the incremental conventional pollutant removals for the BCT options, BPT baseline compliance costs and pollutant removals for drilling fluids and drill cuttings determined. BPT limitations for drilling fluids and drill cuttings prohibit the discharge of drilling fluids and the associated cuttings with free oil, as determined by the visual sheen test. The estimated costs incurred by industry to comply with the BPT limitations consist of: (1) transportation and onshore disposal costs for all oil-based drilling fluids and the associated cuttings and (2) a product substitution cost to replace diesel oil with mineral oil to comply with the BPT no discharge of free oil limitation.

Prior to 1988, drilling wastes generated in Cook Inlet that were not allowed to be discharged were transported to shore for disposal at the Sterling Special Waste Site (SSWS) on the Kenai Peninsula.[13] Because this landfill was permitted to accept drilling wastes and was available to all operators in Cook

Inlet, the BPT cost for disposal is based on all drilling wastes such as oil-based drilling fluids and the associated cuttings being transported to shore for disposal at SSWS at the 1988-time period cost of $26.99 per bbl for cuttings and $29.29 per bbl for drilling fluids.[2]

Before BPT effluent limitations were promulgated, the general industry practice was to use diesel oil for lubricity and as a pill to free stuck pipe. After promulgation of the BPT limitation of no discharge of "free oil" and because diesel oil was shown to form a visible sheen even in small concentrations, the industry replaced diesel oil with mineral oil as a lubricant and in many instances, as a pill in order to be able to discharge the drilling fluids and cuttings.[2] Therefore, a diesel-to-mineral oil substitution cost is also attributed to compliance with BPT discharge limitations.

Before the 1985 proposed BAT limitations, water-based drilling fluids could be formulated with a higher mineral oil content for lubricity and still pass the "no free oil" limitation. Therefore, for the purpose of estimating BPT compliance costs, it is assumed that a typical water-based drilling fluid used prior to 1985 contained 3% mineral oil by volume for lubricity.[2] The current mineral oil content, by comparison is generally in the area of 0.02%.[9]

The average well depth was calculated from the 1993 Coastal Oil and Gas Questionnaire to be 11,765 feet.[8] Before 1985, oil-based muds were used beyond 10,000 ft for all new wells.[2] Under the BPT "no free oil" limitation, the volume of drilling fluids and the associated cuttings beyond 10,000 ft could not be discharged, and were hauled to shore for disposal.

The compliance costs and conventional pollutant removals for the BPT baseline for coastal wells were estimated using the model well characteristics developed for drilling wastes in the Alaska region for the offshore regulation.[2] The volume of drilling fluids and cuttings requiring disposal under the BPT limitation were calculated for an average well depth of 11,765 feet. Only the volume of drilling fluids and cuttings generated beyond 10,000 feet were assumed to require onshore disposal due to the BPT limitations. The drilling fluids and cuttings volume per well for Cook Inlet were obtained from the 1993 Coastal Oil and Gas Questionnaire (Appendix X-1). Table X-9 presents the calculations for the volume of drilling fluids and drill cuttings generated for the coastal model well. As shown in Table X-9, a total of 2,076 bbl/well of drilling fluids and cuttings would require onshore disposal under the BPT limitations. Of the 2,076 bbl of drilling wastes generated beyond 10,000 feet, the drilling fluid represents 81% (1,682 bbl) and the cuttings represent 19% (394 bbl) (Appendix X-1).

TABLE X-9

VOLUME OF DRILLING FLUIDS AND CUTTINGS GENERATED FROM THE COASTAL MODEL WELL

Depth Interval	Average Depth (feet)	Muds & Cuttings Volume (bbl/well)	Muds Volume(a) (bbl/well)	Cuttings Volume(a) (bbl/well)	Drilling Rate (bbl/ft)
Coastal Well Waste Generation Data (a)					
0-2,553	2,553	3,497	2,833	664	1.370
2,553-9,901	7,348	8,703	7,049	1,654	1.184
9,901-11,765	1,865	2,194	1,777	417	1.176
Total:		14,394	11,659	2,735	
Recalculated Coastal Well Data (b)					
0-,2553	2,553	3,497	--	--	--
2,553-8,000	5,447	6,449	--	--	--
8,000-9,901	1,901	2,251	--	--	--
9,901-10,000	99	116	--	--	--
10,000-11,765	1,765	2,076	--	--	--
Total:		14,389			
Recalculated Coastal Well Waste Generation Volumes (c)					
0-8,000	8,000	9,946	8,057	1,889	--
8,000-10,000	2,000	2,367	1,917	450	--
10,000-11,765	1,765	2,076	1,682	394	--
Total:		14,389	11,656	2,734	

(a) Source: Appendix X-1
(b) Coastal well data subdivided to fit the offshore model well depth intervals.
(c) Calculated using offshore model well depth intervals and coastal well volumes per interval.

Due to the solids control system, a portion of the drilling fluid is disposed with the cuttings, and a portion of cuttings is disposed with the drilling fluid. In order to estimate these fractions, it was assumed that the typical solids control system used in drilling operations in Cook Inlet is an intermediate efficiency system, i.e., 62% solids removal efficiency (55 FR 23348). It was also assumed that drilling fluid lost to cuttings represents 2.13 times the cuttings volume removed from the mud system by the solids separation equipment (55 FR 23348). Table X-10 summarizes the volumes of drilling fluids and cuttings calculated for each depth interval based on the solids control system separation efficiency. As

TABLE X-10

VOLUME OF DRILLING FLUIDS AND CUTTINGS GENERATED FROM THE SOLIDS CONTROL SYSTEM OF THE COASTAL MODEL WELL[a]

Volume of Drilling Fluids (bbl/well)							
Depth Interval	Generated	Pill	Total	Mud Lost to Cuttings	Mud System	Cuttings Lost to Mud	Total to Discard
0-8,000	8,057	–	8,057	2,494	5,563	718	6,281[b]
8,000-10,000	1,917	100	2,017	594	1,423	171	1,594[b]
10,000-11,765	1,682	–	1,682	520	1,162	150	1,312[c]
Total:	11,656	100	11,756	3,680	8,148	1,039	9,187

Volume of Cuttings (bbl/well)					
Depth Interval	Generated	Removed	Cuttings Lost to Mud	Mud Lost to Cuttings	Total To Discard
0-8,000	1,889	1,171	718	2,494	3,665[a]
8,000-10,000	450	279	171	594	873[a]
10,000-11,765	394	244	150	520	764[b]
Total:	2,733	1,694	1,039	3,608	5,302

[a] Assumed solids removal efficiency: 62% (55 FR 23348)
[b] To surface discharge or recycle
[c] To disposal

shown in Table X-10, a total of 2,076 bbl/well of drilling fluids and cuttings (generated at greater than 10,000 feet) would require onshore disposal under the BPT limitations. Of the 2,076 bbl of drilling wastes generated beyond 10,000 feet, 1,312 bbls of drilling fluid and 764 bbls of cuttings are generated following the solids control system.

To develop the BPT compliance cost and conventional pollutant removals for Cook Inlet, several assumptions were also made about the drilling operations. The assumptions used to characterize a typical drilling scenario before 1985 in Cook Inlet are presented in Table X-11, including diesel and mineral oil usage, disposal and product substitution costs, and typical drilling mud composition.

Table X-11 also includes the calculations for the disposal costs and conventional pollutant removals. The total disposal costs associated with compliance with the BPT limitations for the coastal

model well include the diesel-to-mineral oil substitution cost plus the disposal cost for oil-based drilling fluid and associated cuttings. The substitution cost was calculated for the volume of drilling fluid generated (9,977 bbl) plus the volume of pill added (100 bbl) in the first 10,000 feet of drilling.

The following calculations present the results of the unit BPT costs for drilling fluids, cuttings, and for the drilling wastes combined. The values used in these calculations were extracted from the information presented in Table X-11.

$$\textit{BPT Cost for Drilling Fluids} = \frac{40{,}275\ \$/well}{(264{,}911 + 207{,}584)\ lb/well} = 0.085\ \$/lb$$

$$\textit{BPT Cost for Cuttings} = \frac{22{,}355\ \$/well}{(297{,}880 + 92{,}895)\ lb/well} = 0.057\ \$/lb$$

$$\textit{Total Drilling Wastes BPT Cost} = \frac{(40{,}275+22{,}355)\ \$/well}{(565{,}791+300{,}479)\ lb/well} = 0.072\ \$/lb$$

6.3 BCT Options

The two BCT candidate options for drilling fluids and cuttings in Cook Inlet are:

- **Option 2 (previously described):** Zero discharge except for Cook Inlet where discharges of drilling fluids and cuttings are allowed if they meet limitations on the cadmium and mercury concentrations in stock barite, no discharge of diesel oil and of free oil as determined by the static sheen test, and a toxicity limitation set between 100,000 and 1,000,000 ppm (SPP).

- **Option 3:** Zero Discharge: All discharges of drilling fluids and cuttings under this option would be prohibited.

Option 1 which is zero discharge everywhere except for Cook Inlet which would be subject to the same as offshore limitations, including a toxicity limitation of 30,000 ppm (SPP) is not considered a BCT option. No additional removal of conventional pollutants due to the toxicity limitation of 30,000 ppm (SPP) over that removed by BPT (free oil discharge prohibition) could be determined. However, a more stringent toxicity limitation, imposed under Option 2, would indirectly remove additional conventional pollutants, whether the final rule sets the toxicity limitation at 100,000 ppm (SPP) or at 1,000,000 ppm (SPP), or somewhere in between. The industry has indicated that under the current

TABLE X-11
BPT DRILLING ASSUMPTIONS

1) Typical BPT Drilling Scenario
a) 12% of all wells used water-based drilling fluids with mineral oil lubricity for the first 10,000 feet.[2]
b) 22% of all wells experienced stuck pipe between 8,000 feet and 10,000 feet of well depth.[2]
c) All wells used oil-based drilling fluids beyond 10,000 feet.[2]
d) All rigs used intermediate efficiency solids control systems.
2) Diesel/Mineral Oil Usage
a) Diesel oil was used pre-BPT for both lubricity and as a pill.[2]
b) Mineral/diesel oil for lubricity equals 3% of drilling fluid volume.[2]
c) One mineral/diesel oil pill equals 100 bbl.[2]
d) Oil-based drilling fluids contain 60% by volume mineral oil.[2]
e) Cost to substitute mineral oil for diesel oil equals $2.00/gal ($84.00/bbl).[2]
3) Typical Mud Composition
a) Drilling fluids contain a total of 113 lb/bbl total suspended solids (TSS) (Appendix X-1).
b) Density of cuttings removed by solids control system is 980 lb/bbl (Appendix X-1).
c) Cuttings retained in the mud system are low gravity solids with a density of 910.7 lb/bbl.[24]
d) Specific gravity of mineral oil is 0.85.[2] This converts to a density of 297.74 lbs/bbl (0.85 x 350 lbs water/bbl).
4) Disposal Cost
a) Cuttings disposal cost is $29.26/bbl.[2]
b) Drilling fluids disposal cost is $26.99/bbl.[2]
c) Mineral oil substitution cost (BPT): [(9,977 bbl mud/well) x (0.03x0.12) + (100 bbl pill/well) x (0.22)] x $84/bbl = $4,864/well
d) Total cuttings disposal cost (BPT): (764 bbl cuttings/well) x (29.26 $/bbl) = $22,395/well
e) Total drilling fluids disposal cost (BPT): [(1,312 bbl mud/well) x (26.99 $/bbl)] + $4,864/well = $40,275/well
5) Conventional Pollutant Removals[a]
a) TSS in drilling fluid disposed (BPT): (113 lb/bbl) x (1,162 bbl mud/well) + (150 bbl cuttings/well) x (910.7 lb/bbl) = 267,911 lb/well
b) Oil in drilling fluid disposed (BPT): (1,162 bbl mud/well) x (0.6) x (297.74 lb/bbl) = 207,584 lb/well
c) TSS in cuttings disposed (BPT): (244 bbl cuttings/well) x (980 lb/bbl) + (520 bbl mud/well) x (113 lb/bbl) = 297,880 lb/well
d) Oil in cuttings disposed (BPT): (520 bbl mud/well) x (0.6) x (297.74 lb/bbl) = 92,895 lb/bbl

[a] Results of calculations are derived from spreadsheets that include automatic rounding.

practices (Option 1), only about 1% of all drilling wastes are not discharged.[5] For the purpose of calculating results of the BCT cost tests, a compliance rate of 83 percent was used, based on evaluating the volume of drill wastes identified as being discharged in a summary database from operations in Cook Inlet.[18] Tables X-4.1 and X-4.2 in Appendix X-4 contain a description of the data excluded from the data used in this evaluation.

For each BCT candidate option, an analysis was performed to determine:

- Cost incurred by the industry to comply.
- Volume of drilling fluids and cuttings not discharged.
- The amount of conventional pollutants not discharged.
- BCT cost reasonableness tests.

6.3.1 BCT Compliance Costs and Pollutant Removals

BCT compliance costs and conventional pollutant removals were estimated for Options 2 and 3 using several assumptions, an average drilling fluid and cuttings volume generated per well, industry-projected numbers of new and recompletion wells that will be drilled from 1996 through 2002, a model drilling fluid composition, and a drilling waste disposal cost based on a combination of disposal methods (landfill for those operators that have access to a landfill, and disposal into a dedicated injection well for the remaining operators). The disposal scenarios were established through the BAT cost analysis presented in Section 5.1.

To develop the BCT compliance cost and conventional pollutant removals for Cook Inlet, several assumptions were made about the drilling operations. The assumptions used to characterize a typical drilling scenario in Cook Inlet, disposal costs, and conventional pollutant removals in drilling fluids and cuttings are presented in Table X-12. Because the mineral oil content in drilling fluids may vary up to 2% by volume when a pill is used[25], two versions of a typical drilling fluid composition have been developed. The BCT cost analysis presented in the following section is based on a typical drilling fluid containing 0.02% by volume of mineral oil, referred to as Version 1. Appendix X-5 presents the BCT cost analysis based on a typical drilling fluid containing 2% by volume mineral oil, referred to as Version 2.

The incremental costs and pollutant removals as measured from BPT-level treatment are based on the additional volume of drilling wastes above 10,000 ft that require disposal due to the BCT limitations. This volume was estimated as follows:

- Volume of drilling wastes above 10,000 ft:

  14,389 bbl/well - 2,076 bbl/well = 12,313 bbl/well (see Table X-7)

- Incremental volume of drilling wastes requiring disposal under Option 2:

  (12,313 bbl/well) x (0.17) = 2,093 bbl/well

TABLE X-12
BCT DRILLING ASSUMPTIONS

1) Typical BCT Drilling Scenario

a) All wells use water-based drilling fluids with mineral oil for lubricity.
b) All rigs use intermediate 62% efficiency solids control systems (55 FR 23348).
c) Average volume per well is 14,389 bbl/well (Appendix X-1)

2) Mineral Oil Usage

a) Mineral oil for lubricity equals 0.02% of drilling fluid volume - Version 1.[2]
b) Residual mineral oil in the discharged mud when pill is added equals 2%[25] - Version 2.
c) Mineral oil substitution cost is $2.00/gal ($84.00/bbl).[2]

3) Typical Mud Composition

a) Drilling fluids contain a total of 113 lb/bbl total suspended solids (TSS) (Appendix X-1).
b) Density of cuttings removed by solids control system is 980 lb/bbl (Appendix X-1).
c) Cuttings retained in the mud system are low gravity solids with a density of 910.7 lb/bbl.[24]
d) Specific gravity of mineral oil is 0.85.[2] This converts to a density of 297.74 lbs/bbl (0.85 x 350 lbs water/bbl).
e) Drilling fluids and cuttings volumes represent of the total drilling wastes generated 81% and 19%, respectively (Appendix X-1).

4) Disposal Cost

a) Drilling wastes disposal cost for Option 2 is $76.00/bbl (Appendix X-1).
b) Drilling wastes disposal cost for Option 3 is $42.00/bbl (Appendix X-1).
c) Mineral oil substitution cost for Option 2 - Version 1, only:
(12,313 bbl/well) x (0.81) x (0.0002) x (84 $/bbl) = $168/well
d) Total cuttings disposal cost (Option 2):
(2,093 bbl/well) x (0.19) x (76.00 $/bbl) = $30,226/well
e) Total drilling fluids disposal cost (Option 2):
(2,093 bbl/well) x (0.81) x (76.00 $/bbl) + $168/well = $129,026/well
f) Total cuttings disposal cost (Option 3):
(12,313 bbl/well) x (0.19) x (42.00 $/bbl) = $98,258/well
g) Total drilling fluids disposal cost (Option 3):
(12,313 bbl/well) x (0.81) x (42.00 $/bbl) = $418,888/well

5) Conventional Pollutant Removals

a) TSS in drilling fluid disposed (Option 2):
(113 lb/bbl) x (2,093 bbl/well) x (0.81) = 191,592 lb/well
b) Oil in drilling fluid disposed (Option 2 - Version 1):
(2,093 bbl/well) x (0.81) x (0.0002) x (297.74 lb/bbl) = 101 lb/well
c) TSS in cuttings disposed (Option 2):
(2,093 bbl/well) x (0.19) x (980 lb/bbl) = 389,756 lb/well
d) TSS in drilling fluids disposed (Option 3):
(12,313 bbl/well) x (0.81) x (113 lb/bbl) = 1,127,009 lb/bbl
e) Oil in drilling fluids disposed (Option 3 - Version 1):
(12,313 bbl/well) x (0.81) x (0.0002) x (297.74 lb/bbl) = 594 lb/well
f) TSS in cuttings disposed (Option 3):
(12,313 bbl/well) x (0.19) x (980 lb/bbl) = 2,292,681 lb/well

6.4 BCT COST TEST CALCULATIONS

The BCT incremental compliance costs and pollutant removals are a result of the disposal of drilling wastes either to a privately owned landfill or injection through a dedicated injection well. Since the cost reasonableness methodology is concerned with the cost of conventional pollutant removals under BCT as it is applied incrementally to BPT, the effects of existing permit or BAT option limitations which may be more stringent than BPT (such as diesel and metals limits for stock barite in drilling fluids) are not considered for the cost reasonableness tests. However, as described previously, some level of toxicity is believed to have an effect on the amount of oil in the wastes, thus a toxicity limitation is being considered as one BCT option.

The results of the BCT cost reasonableness tests for the candidate options for drilling fluids and cuttings are presented in Table X-13 for version 1 of this analysis. The results of version 2 BCT options analysis are shown in Appendix X-5.

TABLE X-13

BCT COST TEST RESULTS FOR DRILLING FLUIDS AND CUTTINGS - COOK INLET
(VERSION 1 - Total oil content in the drilling fluid is 0.02% by volume)

Regulatory Option	Conv. Poll. Removal* (lb/well)	Compliance Cost* ($/well)	POTW Cost ($/lb)	Pass POTW (<0.534)	BPT Cost ($/lb)	ICR Ratio	Pass ICR (<1.29)
Drilling Fluids							
Option 2	191,693	129,026	0.673	No	0.085	--	--
Option 3	1,127,603	418,888	0.371	Yes	0.085	4.365	No
Drill Cuttings							
Option 2	389,756	30,226	0.078	Yes	0.057	1.368	No
Option 3	2,292,681	98,258	0.043	Yes	0.057	0.754	Yes
Drilling Fluids and Cuttings							
Option 2	581,449	159,252	0.274	Yes	0.072	3.806	No
Option 3	3,420,284	517,146	0.151	Yes	0.072	2.097	No

*Incremental to BPT.

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SECTION XI

COMPLIANCE COST AND POLLUTANT LOADING DETERMINATION—PRODUCED WATER

1.0 INTRODUCTION

This section presents the estimated compliance costs and reductions in pollutants discharged as a result of the proposed set of treatment options developed for produced water in the coastal regions of the Gulf of Mexico and Cook Inlet, Alaska. The technology costs represent additional investment required beyond those costs associated with BPT technologies. The compliance costs and pollutant reductions developed for the proposed options are presented in Sections 5.1 and 5.2.

Treatment technology costs were estimated on a facility-specific basis using actual facility profile information. For operators in the Gulf of Mexico, regulatory compliance costs and pollutant removals were estimated for each production facility that will continue to discharge produced water after July 1996, based on mathematical cost model equations. For operators in Cook Inlet, compliance costs and pollutant removals were estimated for each production facility that currently discharges produced water, based on the current level of treatment at each facility.

2.0 OPTIONS CONSIDERED AND SUMMARY COSTS

Five regulatory options were evaluated for produced water in terms of costs and pollutant removals. These five options are based on either injection, improved operating performance of gas flotation, or BPT technologies. The limitations associated with the discharge technologies are for oil and grease. The five options are as listed below:

Option 1 - (BPT All): EPA has included as an option setting effluent limitations equal to the existing BPT requirements. Oil and grease would be limited in the effluent at 48 mg/l monthly average, and 72 mg/l daily maximum.

Option 2 - (Flotation All): All discharges of produced water would be required to meet limitations on oil and grease content of 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 Discharge: Cook Inlet BPT): With the exception of facilities in Cook Inlet, Alaska, all coastal oil and gas facilities would be prohibited from discharging produced water. Coastal facilities in Cook Inlet would be required to comply with the existing BPT effluent

limitations for oil and grease specified under Option 1.

Option 4 - (Zero Discharge: Cook Inlet Flotation): With the exception of facilities in Cook Inlet, Alaska, all coastal oil and gas facilities would be prohibited from discharging produced water. Coastal facilities in Cook Inlet would be required to comply with the oil and grease limitations of 29 mg/l monthly average and 42 mg/l daily maximum based on improved operating performance of gas flotation.

Option 5 - (Zero Discharge All): This option would prohibit all discharges of produced water based on reinjection of the produced water.

Table XI-1 summarizes the BAT and NSPS incremental compliance costs for the five regulatory options. BAT incremental compliance costs listed in Table XI-1 are equal to the capital and operating and maintenance (O&M) costs of each given technology. For scenarios in which gas flotation systems are already in place (i.e., specific Cook Inlet platforms), the incremental cost is only the O&M cost associated with improved operation of the existing technology. In addition, Option 1 incurs zero incremental costs because it sets all limitations equal to BPT.

TABLE XI-1

SUMMARY OF INCREMENTAL BAT AND NSPS COMPLIANCE COST ESTIMATES (1992 $)

Options	BAT Costs		NSPS Costs	
	Capital Cost ($)	O&M Cost ($/yr)	Capital Cost ($)	O&M Cost ($/yr)
Option 1: BPT All	0	0	0	0
Option 2: Improved Gas Flotation All	44,897,167	5,677,889	913,747	147,815
Option 3: Zero Discharge All Except Cook Inlet (BPT for Cook Inlet)	80,423,518	16,629,622	1,729,887	392,986
Option 4: Zero Discharge All Except Cook Inlet (offshore limitations for Cook Inlet)	88,536,994	17,664,732	1,729,887	392,986
Option 5: Zero Discharge All	164,773,267	26,137,105	1,729,887	392,986

The incremental costs for NSPS are also equal to the capital and O&M costs for each given technology. No new sources are expected for Cook Inlet. Therefore, NSPS costs and pollutant reductions are predicted only for the Gulf of Mexico. Table XI-1 also presents the NSPS incremental

compliance costs for the two regulatory options of gas flotation (Option 2) and zero discharge (Options 3, 4 and 5). The derivation of these costs is explained in detail in the remainder of this section.

In order to generate estimates of costs and pollutant removals for each option, EPA used existing industry profile information. The industry profile information was obtained from studies described in Section V, and includes state discharge monitoring data, EPA site visits and sampling reports, and direct contacts with the operators. This information consists of the following elements:

- Identification of currently discharging production facilities including name of the operator, state discharge permit number, location of the producing field, produced water discharge volumes, and date of compliance with state requirements for no discharge where applicable.

- Contaminant levels in produced water from BPT treatment.

All options considered for this regulation beyond the BPT level of control for the coastal region are based on two treatment technologies:

- Filtration followed injection of produced water into a compatible geologic formation, either for disposal or for waterflooding. For operators in the Gulf of Mexico, the injection option includes cartridge filtration as pretreatment followed by injection for disposal. For Cook Inlet operators, the injection option includes granular media filtration and gas flotation as pretreatment followed by injection either for waterflooding or for disposal.

- Improved operating performance of gas flotation followed by discharge to surface water.

In referring to the options considered for control of produced water discharges, the Gulf of Mexico and Cook Inlet are presented separately in the option descriptions and accompanying discussion. All other coastal areas are practicing zero discharge of oil and gas production wastes, and will be subject to this proposal, even though not mentioned specifically.

EPA's Region VI has recently published final NPDES General permits regulating produced water and produced sand discharges to coastal waters in Louisiana and Texas (60 FR 2387, January 9, 1995). The permits prohibit the discharge of produced water and produced sand derived from the coastal subcategory to any water subject to EPA jurisdiction under the Clean Water Act.

Much of the industry covered by this proposed rulemaking is also covered by these General permits. However, a significant difference between the permits and this proposal is that the permits do

not cover produced water discharges derived from the Offshore subcategory wells into the main deltaic passes of the Mississippi River, or to the Atchafalaya River below Morgan City including Wax Lake Outlet. This rulemaking would cover these discharges.

Due to the close proximity of the timing of the publication of the Region VI permits and this proposal, this document presents the costs and impacts of this proposed rulemaking as if the Region VI General permits were not final. The Region VI permit covers approximately 71% of the produced water volume being discharged in the coastal subcategory. The remaining 29% is derived from coastal facilities treating offshore produced waters and currently discharging them into main deltaic river passes in Louisiana, as well as from other coastal operations in the U.S.

The compliance costs of this rulemaking (including the facilities covered by the Region VI permit) are shown in Table XI-1. With the Region VI General permits final, the costs of this rule would be reduced to approximately $19.9 million annually.[20]

EPA will more fully incorporate regulatory effects of the Region VI General permits upon promulgation of the final rule.

3.0 COMPLIANCE COST METHODOLOGY FOR EXISTING FACILITIES IN THE GULF OF MEXICO

EPA determined that 216 production facilities will be discharging produced water as of July 1996. The treatment/disposal technologies evaluated and costed for disposal of produced water from these facilities are based on: 1) zero discharge by injection, and 2) effluent limitations based on improved operating performance of gas flotation. Three treatment/disposal scenarios have been developed for production facilities in the Gulf of Mexico region, as follows:

1) Production facilities with low produced water flow, referred to hereafter as small-volume facilities, will transport the produced water to a commercial facility for injection. There are 50 facilities in this category.

2) Production facilities with medium to high produced water flow, referred to hereafter as medium/large facilities, will treat or inject onsite. There are 166 facilities in this category.

3) For situations in which more than one production facility exists in a field and is operated by the same company, discharges are assumed to be combined for injection or treatment. There are a total of 46 production facilities in this category for the zero discharge option and 36 for the improved gas flotation option.

The cut-off flowrate separating small from medium/large-volume facilities was determined using a cost comparison analysis. The cut-off value ranged from 70.5 bpd to 108.4 bpd depending on the type of facility and the technology option considered. This analysis is described in Section 3.4

This section describes the development of compliance costs in terms of capital and operating and maintenance (O&M) costs for production facilities in the coastal Gulf of Mexico region. For the purpose of clarity, certain terminology used in this section is defined as follows:

Design cost data: Produced water flow rates and capital and O&M costs developed from actual equipment design and cost data obtained form oil and gas operators and equipment vendors. The term "design cost data" refers to both the "design costs" and the "design flows" (each defined below). The design cost data were used to develop mathematical models to best represent the relationship between cost and flow in order to predict facility-specific compliance costs.

Design flows: Produced water flow rates specifically selected using available treatment equipment sized and best engineering judgement.

Design costs: Capital and O&M design costs were calculated from actual equipment cost data obtained from oil and gas operators and equipment vendors. Design costs were calculated for each selected design flow.

Information and data obtained from EPA site visits, oil and gas production operators, vendor quotes, cost information developed by the Energy Information Administration (Department of Energy), and engineering analysis were used to estimate design costs based on selected design flows. The design cost data were then used to develop mathematical models that best represented the relationship between the design costs and the design produced water flows.

Following the cost equation development process, actual facility-specific discharge flows were inserted into the equations to calculate capital and O&M compliance costs. The sources of the actual discharge data were state discharge monitoring reports (DMRs) from Louisiana and Texas.[1] State permit data show that 216 production facilities will be discharging produced water after July 1, 1996. Capital and O&M compliance costs were derived for each of the 216 production facilities based on individual flow and location information.[1] Produced water flows for these facilities reportedly range from 1 barrel per day (bpd) to 144,000 bpd.

The regulatory compliance costs were estimated for all options based on several general assumptions for future produced water volumes and for the location of the production facilities. Future produced water volumes are required when sizing and costing the treatment equipment. Production

facility location is required for assigning the injection well cost and the retrofit cost, which are different for land location than for water location. The following are these general assumptions:

1) Future produced water volume increases by the same rate for both oil and natural gas producing wells. While produced water volumes from gas producing wells will generally not increase by the same rate as from oil producing wells, EPA did not differentiate between them.

2) Capital costs for facilities that will continue to discharge produced water after July 1, 1996 were estimated by assuming a future produced water flow 1.5 times the current flow.[2] The use of this factor, which is a standard engineering design practice, has resulted in an overall conservative capital cost estimate. Many operators have indicated a factor of 1.2 to 1.25 is typically used when sizing and costing produced water treatment equipment.[3]

3) All Louisiana-based production facilities have water access.

4) All Texas-based production facilities have land access.

For purposes of estimation, all Texas production facilities were assumed to be located on land and all Louisiana production facilities were assumed to be located over water. However, EPA is aware that some facilities in Louisiana are located over land and some facilities in Texas are located over water. In the absence of specific location information for all of the 216 discharging facilities, EPA determined this to be a good approximation since the coastal topography of Louisiana consists of more extensive wetlands than that of Texas. The location of the production facility is an important factor when determining the cost of drilling an injection well, and the cost of produced water transportation.

However, EPA also investigated the location of each discharge in Texas to determine the accuracy of the above estimation. The state permit data for Texas includes the longitude and latitude for most produced water outfalls. In order to more specifically estimate the location of Texas production facilities from the state data, EPA assumed that the production facility location is the same as the outfall location. As a result, 42 facilities were estimated as being over water.[21] A sensitivity analysis was performed to determine whether or not a significant cost differential occurs by costing all 126 Texas facilities on land versus 84 on land and 42 over water. This analysis was performed for the zero discharge option only as a "worst case" test. Table XI-2 presents the results which show a small difference between the two cost bases. Capital costs are higher for injection over water than on land because of higher injection well installation and retrofit costs. The O&M costs are slightly lower for water- than land-access because pretreatment over water includes cartridge filtration, whereas backwashing is used over land, which is more costly. The difference in the total capital cost for Gulf of Mexico for water and land locations in

TABLE XI-2
COMPARISON OF COSTS FOR ZERO DISCHARGE OF PRODUCED WATER IN THE COASTAL GULF OF MEXICO

	All Texas facilities on land[a]				Texas facilities on land or water[b]			
	No. Fac.	Flow (bpd)	Cap. Cost ($)	O&M Cost ($/yr)	No. Fac.	Flow (bpd)	Cap. Cost ($)	O&M Cost ($/yr)
SMALL - VOLUME FACILITIES IN TEXAS								
Water-Access	0	0	0	0	10	237	633,339	214,189
Land-Access	38	1,033	1,083,380	625,895	21	515	598,710	312,039
Total	38	1,033	1,083,380	625,895	31	752	1,232,049	526,228
MEDIUM/LARGE - VOLUME FACILITIES IN TEXAS								
Water-Access	0	0	0	0	32	16,588	9,816,526	894,677
Land-Access	88	72,285	16,191,018	3,317,232	63	55,978	11,572,190	2,392,596
Total	88	72,285	16,191,018	3,317,232	95	72,566	21,388,716	3,287,273
TOTAL FOR THE GULF OF MEXICO[c]								
Louisiana	90	415,919	63,149,120	12,686,495	90	415,919	63,149,120	12,686,495
Texas	126	73,318	17,274,398	3,943,127	126	73,318	22,620,765	3,813,501
Grand Total	216	489,237	80,423,518	16,629,622	216	489,237	85,769,885	16,499,996

a Capital and O&M costs are based on the assumption that all discharging facilities in Texas are land based.
b Capital and O&M costs are based on some facilities in Texas being located over water.
c Total capital and O&M costs for the Gulf of Mexico for the three scenarios, including Louisiana.

Texas is only 6% higher than for all land locations.

In addition, it should be noted that as discussed in Section IV of this document, out of the 216 facilities EPA has determined to be discharging in 1996, seven facilities in Nueces Bay, Texas will actually cease discharging in 1995. Costs for these facilities have been left in EPA's cost analysis presented here, resulting in an over-estimate of O&M cost by 1.9% and of capital cost by 1.4% for the zero discharge numbers (See Appendix XI-4). EPA plans to delete the costs for these facilities prior to calculating costs for the final rule.

3.1 Design Capital and O&M Costs For Small-Volume Facilities

For all treatment options, small-volume facilities transport produced water either by barge or by truck to a commercial facility for disposal. For these facilities, the capital cost includes the cost of installing a storage tank to provide for sufficient onsite storage capacity. The O&M cost includes the transportation cost plus the disposal cost charged by the commercial disposal facility. The following general assumptions were used to develop design costs for all small-volume facilities:

- Small-volume facilities with water access transport produced water to a commercial facility by barge. Based on the produced water flows (<108.4 bpd), these facilities install storage tanks to provide a minimum of 7 days storage capacity which will allow for weekly barge trips by a commercial service company (the storage tank capacity is flow dependent - for details see discussion at the end of Section 3.1).

- A single barge of 3,000 bbl capacity services multiple small-volume facilities to full capacity.[4] The number of facilities serviced by one barge depends on the onsite storage capacity, the distance between facilities, and the distance to the commercial disposal facility. An average per barrel cost was developed based on assumed distances described in Section 3.1.2

- Small-volume facilities with land access install one 150 bbl storage tank and transport produced water by truck to a commercial facility for disposal. The 150 bbl capacity was selected because it exceeded the volume of the vacuum truck. The low produced water flowrate of small-volume facilities (<70.5 bpd) allows plenty of time to schedule truck service.

- Small-volume facilities with land access are serviced by vacuum trucks which have a capacity of 119 bbl.[5] Trucks are readily available and the number of truck trips depends on the volume of produced water generated. An average per barrel cost was developed based on assumed distances described in Section 3.1.2

3.1.1 Design Capital Cost

For small-volume facilities, capital costs for all design flows include the following:

- **Storage Tank Purchase Cost:** The purchase cost depends on the storage tank capacity. Purchase costs were available for tanks of 150 bbl, 1,000 bbl, and 1,500 bbl storage capacities.[4] Purchase costs for tanks with storage capacities of 300 bbl and 500 bbl were obtained by interpolating the costs for the 150 bbl, 1,000 bbl, and 1,500 bbl tanks.[6]

- **Installed Costs:** Equipment installation costs include the piping cost (15% of the purchase cost), installation labor cost (32% of the purchase cost), and transportation cost (5% of the purchase cost).[4] The equipment installation costs were calculated as fractions of the total equipment purchase costs based on the best available estimates of actual costs obtained from EPA sampling trips.[4]

- **Additional Costs (Engineering, Contingency, and Insurance-Bonding Fees):** These fees were added to the equipment purchase and installation costs to develop actual capital costs. These fees include all engineering design costs (10% of equipment installation cost), administrative costs (4% of equipment installation cost), and any incidental costs incurred in the process of purchasing and installing the equipment (15% of equipment installation cost).[6]

- **Platform/Concrete Pad Retrofit Costs:** Equipment space requirements were estimated to be twice the footprint. The retrofit costs were $75/ft^2$ and $40/ft^2$ for facilities with water access and land access, respectively.[4]

Total capital costs include platform retrofit costs for facilities with water access or concrete pad retrofit cost for facilities with land access. The information obtained during EPA's sampling trips shows that equipment space requirements vary between two to three times the footprint, with tanks requiring less additional space than pumps and filters. The total area requirements for equipment on offshore platforms was reported to be twice the footprint.[7] The benefits from minimizing equipment space requirements are two fold: one is the economic aspect of reduced retrofit cost, and the second is the reduction of the impact of human activities on the surrounding environment. Therefore, for coastal oil and gas operations, equipment space requirements were assumed to be twice the footprint. The retrofit costs used in this analysis were $75.00/ft^2$ for platforms at facilities with water access and $40.00/ft^2$ for concrete pads at land-accessed facilities.[4]

The following design criteria, which directly affect the capital costs, were also used for small-volume facilities (see Section 3.1 for rational):

- Facilities with water access and with flows less than or equal to 21 bpd will install one 150 bbl storage tank.

- Facilities with water access and with flows greater than 21 bpd but less than or equal to 43 bpd will install one 300 bbl storage tank.
- Facilities with water access and with flows greater than 43 bpd but less than or equal to 71 bpd will install one 500 bbl storage tank.
- Facilities with water access and with flows greater than 71 bpd but less than or equal to 143 bpd will install one 1,000 bbl storage tank.
- Facilities with water access and with flows greater than 143 bpd but less than or equal to 214 bpd will install one 1,500 bbl storage tank.

A mathematical model was not necessary in developing compliance costs for small-volume facilities because the capital costs are estimated as discrete values associated with discrete tank capacities. Table XI-3 shows that for five different tank sizes, five capital costs were calculated for water-access facilities. For land-access facilities, Table XI-3 lists only one capital cost for all flows because of the assumptions that: 1) all land-access facilities will install a 150 bbl tank, and 2) 119 bbl vacuum trucks are readily available and have unlimited access to these sites.

3.1.2 Design O&M Cost

For small-volume facilities with water access, O&M costs include the transportation cost that the barge service company will charge plus the disposal cost charged by the commercial disposal company. The average commercial O&M cost was estimated to be approximately $1.63/bbl. The barge service company was assumed to be a commercial operation and therefore the transportation cost is based on known barge and tug rental costs. An average distance of 10 miles between discharging facilities, and a distance of 50 miles to the disposal facility were also assumed.[2,3] Appendix XI-1 shows the assumptions and calculations used to derive the average commercial O&M disposal cost per barrel per facility with water access.

For small-volume facilities with land access, O&M costs include the total transportation cost that the vacuum truck service will charge plus the disposal cost charged by the commercial disposal company. The average commercial O&M cost was estimated to be $1.66/bbl.[4] The transportation cost is based on an average roundtrip distance of 120 miles that a 5,000 gallon (199 bbl) truck will travel. Appendix XI-1 also shows the assumptions and calculations used to derive the average commercial O&M disposal cost per barrel per facility with land access.

O&M costs vary with flow rate, but a mathematical cost model was not necessary for small-

TABLE XI-3
DESIGN CAPITAL AND O&M COSTS FOR SMALL-VOLUME FACILITIES[6]

Flow (bbl)	Water Access			Land Access		
	Tank Capacity (bbl)	Capital Cost (1992 $)	O&M Cost ($/yr)	Tank Capacity (bbl)	Capital Cost (1992 $)	O&M Cost ($/yr)
1-21	150	32,010	595-12,494	150	28,510	606-12,724
<21-43	300	40,607*	12,495-25,583	150	28,510	12,725-26,054
<43-71	500	52,318*	25,584-42,241	150	28,510	26,055-43,019
<71-143	1,000	83,471	42,242-85,078	150	28,510	43,020-86,644
<143-214	1,500	92,687	85,079-127,319	150	28,510	86,645-129,663

* The costs and footprint area requirements for the 300 bbl and 500 bbl storage tanks were obtained by interpolating the costs and footprint area requirements, respectively, for the 150 bbl, 1,000 bbl, and 1,500 bbl storage tanks which were provided.[4]

Example Capital Cost Calculations for 150 bbl storage tank:

	Water Access	Land Access	
Storage Tank	$12,500	$12,500	
Piping (15%)	$1,875	$1,875	
Labor (32%)	$4,000	$4,000	
Transportation (5%)	$625	$625	
Subtotal:	$19,000	$19,000	
Engineering (10%)	$1,900	$1,900	
Contingency (15%)	$2,850	$2,850	
Ins./Bonding (4%)	$760	$760	
Subtotal:	$24,510	$24,510	
Platform/Concrete Pad	$7,500	$4,000	(based on 100 ft^2 footprint requirements)
Total Capital Cost	$32,010	$28,510	

volume facilities. Annual O&M costs were simply calculated by assuming that regardless of flow or storage tank size, average commercial disposal costs are $1.63/bbl for water-access sites and $1.66/bbl for land-access sites. Hence, the total O&M costs shown in Table XI-1 for either water-access or land-access are simply the flow (bpd) times 365 days/yr times the average commercial costs. For example, a facility with water access and a flow of 22 bpd, under this scenario, will incur a capital cost of $40,607 and O&M cost of $12,495/yr.

3.2 Design Capital and O&M Costs For Medium/Large-Volume Facilities

As previously stated, costs for medium/large-volume facilities were developed by first estimating design costs based on selected design flows, and then performing a regression analysis with these data points to derive the cost equations. Eight design flows were selected so that they fell within the actual range of the 166 medium/large-volume discharging facilities. Section 3.2 discusses the design parameters used as the basis for the cost equation derivations. Section 3.3 presents the cost equations.

3.2.1 Injection

Capital and O&M costs for medium/large-volume facilities include the costs of pretreatment by cartridge filtration and the costs of the injection pumps and wells. For production facilities with land access, the proposed injection system does not include pretreatment by cartridge filtration, but rather includes costs for more frequent injection well downhole maintenance. This is because it was found that for land-access facilities, cartridge filtration is less necessary and well workover costs are cheaper.[4]

Based on information obtained during EPA's sampling trips, the most common downhole injection well maintenance performed is a backwash operation.[4] In a backwash operation, the flow in the injection well is reversed to remove the solids that accumulate on the face of the receiving formation that would otherwise interfere with the injection operation.[4] According to information obtained during EPA's sampling trips, the frequency of the backwash operations is facility specific. However, more frequent backwashes were performed where filtration equipment was not used as pretreatment to injection. The frequency of backwash operations and costs are discussed in more detail in Section 3.2.1.2.

3.2.1.1 Design Capital Cost

The design capital costs are based on direct quotes from equipment vendors, summary statistics from the EPA 1993 questionnaire, and standard engineering cost estimating factors. The following list summarizes the assumptions made to develop the design capital costs.

- **Pretreatment:** Facilities with water access are assumed to include cartridge filtration as pretreatment to injection, while facilities with land access are assumed not to install cartridge filtration but rather to conduct more frequent backwashings of the injection wells.

- **Cartridge Filters and Feed Pumps:** were sized based on the design flows and the manufacturer recommended volumetric loads as follows:[9]

  10" cartridge - 7 gpm/cartridge
  20" cartridge - 14 gpm/cartridge
  30" cartridge - 21 gpm/cartridge

  One module can contain a maximum of 4 cartridges. Where design flow exceeds 84 gpm, multiple modules were costed. The cartridge filters are rated for a maximum pressure of 150 psig. Filter feed pumps were sized for the required flow and a discharge pressure of 50 psig.

- **Feed Pumps:** are electrically driven for single-well injection systems or flows up to 5,000 bpd.[10] For multiple well injections systems, the filter feed pumps have natural gas driven motors.

- **Injection Pump Feed Tank:** After filtration, the produced water goes into an injection pump feed tank. The capacity of the feed tank is flow dependent. For facilities processing less than or equal to 1,000 bpd of produced water, a surge tank of 150 bbl capacity was included. This translates into a minimum of 3.6 hrs of surge capacity for the design flow of 1,000 bpd. For facilities processing more than 1,000 bpd but less than or equal to 5,000 bpd of produced water, a surge tank of 1,000 bbl capacity was included. This translates into a minimum of 4.8 hrs of surge capacity for the design flow of 5,000 bpd. For facilities processing more than 5,000 bpd of produced water, a surge tank of 1,500 bbl capacity was included. This translates into 51 minutes of surge capacity for the design flow of 42,000 bpd [(1,500/42,000) bbl/bpd x (24 x 60) min/day]. This assumption is consistent with the Walk-Haydel analysis in which the minimum capacity for the surge tank was assumed to be 3 minutes.[11]

- **Injection Pumps:** are positive displacement pumps capable of delivering the required flow at 1,500 psig. Costs include the pump plus the motor, both skid mounted.[10] Spare pumps are not included because the results of the statistical analysis of the Coastal Oil and Gas Questionnaire show that the majority of injection facilities in the coastal region (i.e., 58%) do not use spare pumps.[12]

- **Spare Wells:** According to studies of producing areas of Louisiana and other areas in the U.S. where injection wells are used to dispose of produced water, operators rarely go to the expense of drilling a "spare" well to handle produced water when the primary disposal well is shut in for servicing.[4,15] Instead, it is more typical for operators to respond by temporarily incurring the costs associated with hauling produced water to commercial disposal facilities, or shutting in the producing well(s) until the disposal well is brought back into service. If the production facility is serving multiple wells, those with the highest water cut are more likely to be shut in for the duration of the injection well workover. Therefore, this analysis assumes that no spare wells are needed.

- **Pump Engines:** The injection pumps with capacities up to 500 bpd, or 12 hp, are electrically driven. For flows greater than 500 bpd, natural gas driven engines are used.

- **Electric Pumps:** For electric pumps and instrumentation, no additional power generation equipment is required. The assumption used here is that existing onsite power generation equipment can handle an excess load of up to 25 hp.

- **Injection Well Capacity:** The average capacity for the injection wells, new or converted, is 5,000 bpd. For flows greater than 5,000 bpd, the number of injection wells and pumps was determined based on one injection well and one pump with a capacity of 5,000 bpd for each 5,000 bbl of flow or portion thereof. For this cost estimating, an average injection well capacity of 5,000 bpd was selected based on information obtained from the 1993 survey of coastal oil and gas industry. This average injection well capacity is based on the statistical analysis of the produced water flow data from facilities that currently inject produced water. The statistical analysis which took into account the effect of underutilization by spare wells, showed that a typical injection well in the Gulf of Mexico has an average capacity of 5,000 bpd.[8] The cost to drill an injection well is dependent on the required drilled depth and the location of the well (whether on land or over water), but to a lesser extent on the capacity of the well.

- **Average Injection Well Cost:** EPA estimated, based on data obtained directly from operators, that 90% of injection wells will be converted from previously producing and abandoned wells and 10% will be newly drilled injection wells.[14] For land-access facilities, the average injection well cost (i.e., average cost of new and converted wells) is $107,500 and for water-access facilities is $246,000, based on 90% of the operators having wells available for conversion to injection wells.

  The cost of a new well at facilities in the Gulf of Mexico region has been estimated to be $175,000 for land-access and $300,000 for water-access.[4] It has been noted that the cost of drilling injection wells in the coastal Gulf of Mexico region does not vary significantly with well capacity for wells having the same depth (Kerr and Assoc., 1990). The cost of converting an existing well to an injection well at facilities in the coastal Gulf of Mexico region has been estimated to be $100,000 for land-access and $240,000 for water-access.[4] Again, the well conversion cost is not affected significantly by the injection capacity of the well (Kerr and Assoc., 1990).

  For water-accessed facilities the average injection well cost was determined as follows:

  Injection Well Cost = 0.9 x $240,000 + 0.1 x $300,000 = $246,000

  For land-accessed facilities the average injection well cost was determined as follows:

  Injection Well Cost = 0.9 x $100,000 + 0.1 x $175,000 = $107,500

- **Platform/Concrete Pad Retrofit Cost:** Equipment space requirements were calculated based on twice the equipment footprint area requirements. See section 3.1.1 for a detailed explanation of this assumption.

- **Pipeline Cost:** is based on $4.06/in of pipe diameter/ft. The piping diameters used in the calculations of piping cost is as recommended in the Walk-Haydel report as follows:[11]

Flows	Pipe Diam.
up to 5,000 bpd	3-inch
5,001 up to 14,000 bpd	4-inch
greater than 14,000 bpd	6-inch

- **Average Pipeline Distance:** The average pipeline distance from the separation/treatment facility to the injection well is assumed to be 3,433 feet for facilities with water access and 794 feet for facilities with land access.[6]

- **Installed Costs:** Equipment installation costs include the piping cost (15% of the purchase cost), installation labor cost (32% of the purchase cost), and transportation cost (5% of the purchase cost).[4]

- **Additional Costs (Engineering, Contingency, and Insurance-Bonding Fees):** These fees were added to the equipment purchase and installation costs to develop actual capital costs. These fees include all engineering design costs (10% of installed equipment cost), administrative costs (4% of installed equipment cost), and any incidental costs incurred in the process of purchasing and installing the equipment (15% of equipment installed cost).[6]

Tables XI-4 and XI-5 present the design capital and O&M costs for the selected design flows for production facilities with water- and land-access, respectively.

3.2.1.2 Design O&M Cost

Design O&M costs for produced water injection are presented in Tables XI-4 and XI-5. The assumptions used to develop design O&M costs for injection are as follows:

- **Labor:** Labor costs are based on an hourly rate of $20.00 per hour and on 2 person-hour per day for the operation of single-well injection systems. Labor costs for multiple-well injection systems with water- and land-access are based on 2.42 person-hour per day and 2.37 person-hour per day, respectively.[12]

- **Fuel:** Fuel cost was calculated based on the maximum pumping horsepower required above 25 hp, continuous operation (365 days per year), and on a natural gas unit cost of $2.50 per 1,000 cubic feet.[4,12]

- **Maintenance Materials:** Maintenance materials represent 5% of the equipment purchase cost.[4]

- **Chemicals:** The cost of adding bactericides and polymer or surfactants was estimated for injection well operation. The unit cost for bactericides addition is $1.095/bpd and for polymer/surfactant is $3.285/bpd.[4]

- **Well Backwash:** Well backwash frequency and unit cost are based on the results of the statistical analysis of the EPA Questionnaire.[12] Well backwash cost is $10,146 per job

TABLE XI-4

DESIGN COST DATA FOR INJECTION AT PRODUCTION FACILITIES WITH WATER ACCESS[6]

Component	Design Flowrate (bpd)							
	200	500	1,000	5,000	10,000	18,000	30,000	42,000
1. Capital Cost (1992 $)								
Purchase Equipment	19,867	21,415	29,877	62,477	111,454	214,108	314,858	465,983
Installation Cost	10,331	11,136	15,536	32,488	57,956	111,336	163,726	242,311
Additional Cost[a]	8,757	9,440	13,170	27,540	49,129	94,379	138,790	205,405
Retrofit Cost	8,813	8,850	9,150	60,675	64,350	71,700	79,050	90,075
Pipeline Cost	41,814	41,814	41,814	41,814	55,752	83,628	83,628	83,628
Injection Well	246,000	246,000	246,000	246,000	492,000	984,000	1,476,000	2,214,000
Total Capital Cost	**335,582**	**338,654**	**355,547**	**470,994**	**830,641**	**1,559,151**	**2,256,051**	**3,301,402**
2. O&M Cost (1992 $/yr)								
Labor	14,600	14,600	14,600	14,600	17,666	17,666	17,666	17,666
Fuel Cost	0	0	7,545	30,539	61,078	122,157	186,828	283,835
Maintenance Mtl.	993	1,071	1,494	3,124	5,573	10,705	15,743	23,299
Chemicals	3,580	8,950	17,900	89,500	179,000	322,200	537,000	751,800
Backwash	5,073	5,073	5,073	5,073	10,146	20,292	30,438	45,657
Total O&M Cost	**24,246**	**29,694**	**46,612**	**142,836**	**273,463**	**493,020**	**787,675**	**1,122,257**

[a] Includes engineering, contingency, and insurance-bonding fees.

TABLE XI-5

DESIGN COST DATA FOR INJECTION AT PRODUCTION FACILITIES WITH LAND ACCESS[6]

Component	Design Flowrate (bpd)							
	200	500	1,000	5,000	10,000	18,000	30,000	42,000
1. **Capital Cost** (1992 $)								
Purchase Equipment	17,200	18,412	26,403	56,819	100,138	191,476	278,114	408,071
Installation Cost	8,944	9,574	13,730	29,546	52,072	99,568	144,619	212,197
Additional Cost[a]	7,582	8,116	11,638	25,046	44,141	84,402	122,593	179,878
Retrofit Cost	4,260	4,280	4,440	31,600	32,800	35,200	37,600	41,200
Pipeline Cost	9,671	9,671	9,671	9,671	12,895	19,342	19,342	19,342
Injection Well	107,500	107,500	107,500	107,500	215,000	430,000	645,000	967,500
Total Capital Cost	**155,157**	**157,553**	**173,382**	**260,182**	**457,045**	**859,988**	**1,247,268**	**1,828,187**
2. **O&M Cost** (1992 $/yr)								
Labor	14,600	14,600	14,600	14,600	17,301	17,301	17,301	17,301
Fuel Cost	0	0	7,545	30,539	61,078	122,157	186,828	283,835
Maintenance Mtl.	860	921	1,320	2,841	5,077	9,574	13,906	20,404
Chemicals	3,580	8,950	17,900	89,500	179,000	322,200	537,000	751,800
Backwash	6,720	6,720	6,720	6,720	13,440	26,880	40,320	60,480
Total O&M Cost	25,760	31,191	48,085	144,200	275,826	498,112	795,355	1,133,820

[a] Includes engineering, contingency, and insurance-bonding fees.

and $9,600 per job for facilities with water- and land-access, respectively. The frequency of well backwash operations is once every two years for facilities with water access and 0.7 per year for facilities with land access.[6] Well backwash is performed more often at land-based facilities because it is assumed that no filtration equipment is installed.

3.2.2 Gas Flotation

The second option evaluated by EPA would establish more stringent than BPT effluent limitations based on improved operating performance of gas flotation technology. This technology would consist of improved operation and maintenance of gas flotation treatment systems, more operator attention to treatment system operations, chemical pretreatment to enhance system effectiveness, and possible resizing of certain treatment system components for increased treatment efficiency. The costs for this option were developed for new gas flotation systems for all discharging facilities in the Gulf of Mexico because gas flotation is not currently used in the coastal states as a BPT treatment technology.[19] Design capital and O&M costs for medium/large-volume facilities include the costs of the gas flotation unit, plus a natural gas driven generator for systems that require more than 25 hp to operate. Costs for natural gas generators were derived based on information developed by Energy Information Administration (Department of Energy).[7] Installed equipment cost is the same for all production facilities, regardless of their location.

3.2.2.1 Design Capital Cost

Tables XI-6 and XI-7 present the design capital and O&M costs for gas flotation for the selected design flows for production facilities with water- and land-access, respectively. Design equipment capital costs for gas flotation in coastal areas were obtained from supporting documentation for the Offshore Development Document that were in 1986 dollars.[16] These figures were adjusted to 1992 dollars by the ratio of Engineering News Record-Construction Indeces (ENR-CCI) of 4985 (1992) to 4295 (1986).

The following list summarizes the assumptions made to develop the design capital costs included here.

- **Equipment Purchase Cost:** The equipment purchase cost for all production facilities includes: gas flotation and feed pump, and natural gas generator for systems that require more than 25 hp to operate (flows greater than 5,000 bpd). Gas flotation equipment cost includes: gas flotation skid-mounted, complete electrical systems, oil and water outlets brought to the edge of the skid, and sufficient instrumentation for proper operation. All gas flotation systems are equipped with electric motors.[5] For systems that require more than 25 hp to operate (i.e., flows greater than 5,000 bpd), the electric power is supplied by natural-gas driven generators.[7]

TABLE XI-6
DESIGN COST DATA FOR GAS FLOTATION AT PRODUCTION FACILITIES WITH WATER ACCESS[6]

Component	Design Flowrate (bpd)								
	200	1,000	2,000	5,000	10,000	15,000	25,000	40,000	80,000
1. Capital Cost (1992 $)									
Purchase Equipment	85,104	86,458	86,458	109,862	184,237	195,398	221,544	263,099	382,013
Installation Cost	39,999	40,635	40,635	51,635	86,591	91,837	104,126	123,657	179,546
Additional Cost[a]	36,280	36,857	36,857	46,834	78,541	83,298	94,444	112,159	162,852
Retrofit Cost	9,375	9,375	9,375	16,725	31,725	35,100	44,550	57,075	96,450
Total Capital Cost	170,758	173,325	173,325	225,056	381,094	405,633	464,664	555,990	820,861
2. O&M Cost (1992 $/yr)	23,438	23,695	23,695	28,133	42,237	44,353	49,311	57,191	79,741

[a] Includes engineering, contingency, and insurance-bonding fees.

TABLE XI-7
DESIGN COST DATA FOR GAS FLOTATION AT PRODUCTION FACILITIES WITH LAND ACCESS[6]

Component	Design Flowrate (bpd)								
	200	1,000	2,000	5,000	10,000	15,000	25,000	40,000	80,000
1. Capital Cost (1992 $)									
Purchase Equipment	85,104	86,458	86,458	109,862	184,237	195,398	221,544	263,099	382,013
Installation Cost	39,999	40,635	40,635	51,635	86,591	91,837	104,126	123,657	179,546
Additional Cost[a]	36,280	36,857	36,857	46,834	78,541	83,298	94,444	112,159	162,852
Retrofit Cost	5,000	5,000	5,000	8,920	16,920	18,720	23,760	30,440	51,440
Total Capital Cost	166,383	168,950	168,950	217,251	366,289	389,253	443,874	529,355	775,852
2. O&M Cost (1992 $/yr)	23,438	23,695	23,695	28,133	42,237	44,353	49,311	57,191	79,741

[a] Includes engineering, contingency, and insurance-bonding fees.

- **Installed Costs:** Equipment installation costs include the piping cost (15% of the purchase cost), and installation labor cost (32% of the purchase cost). No transportation costs were included because the equipment costs represent costs of equipment delivered to the Gulf of Mexico area.[4]

- **Additional Costs (Engineering, Contingency, and Insurance-Bonding Fees):** These fees were added to the equipment purchase and installation costs to develop actual capital costs. These fees include all engineering design costs (10%), administrative costs (4%), and any incidental costs incurred in the process of purchasing and installing the equipment (15%).[6]

- **Platform/Concrete Pad Retrofit Costs:** Equipment space requirements were estimated to be twice the footprint.[6] The retrofit costs were $75/ft^2$ and $40/ft^2$ for facilities with water access and land access, respectively.[4]

3.2.2.2 Design O&M Cost

Estimated design O&M costs for gas flotation treatment are presented in Tables XI-4 and XI-5. The annual operating and maintenance cost was estimated to be 10% of the total capital cost. In addition, labor costs were estimated based on one person-hour per day at a rate of $20.00 per hour.[6] Typically, the operating and maintenance costs include: polymer and/or flocculation enhancement chemicals, fuel cost, and feed pump and agitator maintenance and replacement costs.

3.3 Model Cost Equations

3.3.1 Injection

For the zero-discharge via injection option, eight independent linear cost equations were developed for medium/large-volume facilities: two for single well injection systems with water access (one capital cost equation and one O&M cost equation), two for single injection well systems with land access, two for multiple injection well systems with water access, and two for multiple injection well systems with land access. Again, single injection well systems are assumed for operations with flows less than or equal to 5,000 bpd and multiple injection well systems are assumed for flows greater than 5,000 bpd. Table XI-8 lists the eight cost equations.

The mathematical model best representing the relationship between design flow and design cost for injection was found to be a line of the general form:

TABLE XI-8
CAPITAL AND O&M COSTS EQUATIONS FOR INJECTION OF PRODUCED WATER AT MEDIUM/LARGE-VOLUME FACILITIES[6]

Single - Well Injection Systems

Design Flow (bpd)	Water Access						Land Access					
	Capital Cost ($)			O&M Cost ($/yr)			Capital Cost ($)			O&M Cost ($/yr)		
	Design	Calculated	% Error	Design	Calculated	% Error	Design	Calculated	% Error	Design	Calculated	% Error
200	335,582	332,791	-0.8%	24,246	24,351	+0.4%	155,157	153,863	-0.8%	25,760	25,857	+0.4%
500	338,654	341,415	+0.8%	29,694	31,774	+7.0%	157,553	160,515	+1.9%	31,191	33,271	+6.7%
1,000	355,547	355,789	+0.1%	46,612	44,146	-5.3%	173,382	171,602	-1.0%	48,085	45,628	-5.1%
5,000	470,994	470,781	-0.1%	142,836	143,117	+0.2%	260,182	260,293	+0.1%	144,200	144,479	+0.2%
Cost Equation	327,042 + 28.75x(flow)			19,403 + 24.74x(flow)			149,429 + 22.17x(flow)			20,915 + 24.71x(flow)		

Multiple - Well Injection Systems

Design Flow (bpd)	Water Access						Land Access					
	Capital Cost ($)			O&M Cost ($/yr)			Capital Cost ($)			O&M Cost ($/yr)		
	Design	Calculated	% Error	Design	Calculated	% Error	Design	Calculated	% Error	Design	Calculated	% Error
10,000	830,641	863,586	+4.0%	273,463	274,623	+0.4%	457,045	474,654	+3.9%	275,826	277,116	+0.5%
18,000	1,559,151	1,462,640	-6.2%	493,020	485,013	-1.6%	859,988	807,171	-6.1%	498,112	489,736	-1.7%
30,000	2,256,051	2,361,220	+4.7%	787,675	800,598	+1.6%	1,247,268	1,305,945	+4.7%	795,355	808,665	+1.7%
42,000	3,301,402	3,259,800	-1.3%	1,122,257	1,116,182	-0.5%	1,828,178	1,804,719	-1.3%	1,133,820	1,127,594	-0.6%
Cost Equation	114,769 + 74.88x(flow)			11,635 + 26.30x(flow)			59,009 + 41.56x(flow)			11,342 + 26.58x(flow)		

$$Y = mX + b$$

where: Y = design cost (either capital or O&M cost)

m = slope (X-coefficient)

X = design flow (in barrels per day)

b = Y-intercept (constant)

The constants (y-intercept) and x-coefficients for each of the eight equations were determined using regression analysis with the design costs shown in Tables XI-4 and XI-5 as input data. Note that in Table XI-8, "design" costs are those from Tables XI-4 and XI-5, and "calculated" costs are those generated by the model cost equations for each design flow listed. The comparison of design to calculated costs shows an error of no greater than $\pm$ 7.0% for all systems.

3.3.2 Gas Flotation

For the discharge via gas flotation option, six independent cost equations were developed for medium/large-volume facilities: one capital cost equation for water accessed facilities with flows less than or equal to 5,000 bpd, one capital cost equation for land accessed facilities with flows less than or equal to 5,000 bpd, one O&M cost equation that is the same for these systems, one capital cost equation for water accessed facilities with flows greater than 5,000 bpd, one capital cost equation for land accessed facilities with flows greater than 5,000 bpd, and finally one O&M cost equation that is the same for these greater than 5,000 bpd systems. There are only two O&M cost equations because the location of the production facility, i.e., land or water, does not affect the design O&M cost for gas flotation. However, capital costs are slightly different because of the difference in the retrofit cost for water versus land locations. Table XI-9 lists the six cost equations developed and used to predict regional costs for treatment by gas flotation.

The mathematical model best representing the relationship between design flow and design cost for production facilities with flows up to 5,000 bpd was found to be a function of the general form:

$$Y = a + bX + cX^2$$

For production facilities with flows greater than 5,000 bpd, the best-fit mathematical model is a linear function of the general form:

$$Y = a + bX$$

where: Y = design cost (either capital of O&M cost)

a, b, c = constants

X = design flow (in barrels per day)

The constants (a, b, and c) for each of the six equations were determined using regression analysis with the design costs shown in Tables XI-6 and XI-7 as input data. Note that in Table XI-9, "design" costs are those from Tables XI-6 and XI-7, and "calculated" costs are those generated by the model cost equations for each design flow listed. The comparison of design to calculated costs shows an error of no greater than $\pm$ 3.1% for all systems.

3.4 Determination of Cut-Off Flow For Small- vs. Medium/Large-Volume Facilities

An important step in the development of the model cost equations was the determination of the cut-off flow rate that would distinguish small-volume facilities (those sending produced water to commercial disposal facilities) from medium/large-volume facilities (those injecting or treating the produced water onsite). An analysis was performed to identify the maximum flow rate that a small-volume facility can economically dispose of commercially and the minimum flow rate that a medium/large-volume facility can economically inject or treat onsite. In general, this analysis was performed by developing total annual cost equations from the model cost data listed in Tables XI-3, XI-8, and XI-9, plotting as total annual cost vs. flow rate, and noting the flow rate at which the lines intersect. The following discussion explains the details of this analysis.

Capital and O&M costs for commercial disposal for small-volume facilities with both water and land access were developed based on flows ranging from 5 to 214 bpd as shown in Table XI-3. To annualize the capital cost, a capital recovery factor of 0.1627 was used based on 10 years and 10% interest rate. Total annual costs were then calculated by adding the annualized capital cost and the O&M cost for each design flow. Total annual cost equations were then developed by regression analysis, and plotted against the flow.

Capital O&M costs for onsite single-well injection for medium/large-volume facilities with both water and land access were developed based on flows ranging from 100 bpd to 5,000 bpd using the assumptions identified in Tables XI-4, XI-5, XI-6, and XI-7. To annualize the capital cost, a capital recovery factor of 0.1627 was used based on 10 years and 10% interest rate. Total annual costs were

TABLE XI-9

CAPITAL AND O&M COSTS EQUATIONS FOR GAS FLOTATION

Medium-Volume Gas Flotation Systems

Design Flow (bpd)	Water Access						Land Access					
	Capital Cost ($)			O&M Cost ($/yr)			Capital Cost ($)			O&M Cost ($/yr)		
	Design	Calculated	% Error	Design	Calculated	% Error	Design	Calculated	Error	Design	Calculated	% Error
200	170,758	171,955	+0.7%	23,438	23,547	+0.5%	166,383	167,525	+0.7%	23,438	23,547	+0.5%
1,000	173,325	170,695	-1.5%	23,695	23,497	-0.8%	168,950	166,473	-1.5%	23,695	23,497	-0.8%
2,000	173,325	174,700	+0.8%	23,695	23,975	+1.2%	168,950	170,377	+0.8%	23,695	23,975	+1.2%
5,000	225,056	223,914	-0.5%	28,133	29,008	+3.1%	217,251	216,889	-0.2%	28,133	29,008	+3.1%
Cost Equation	$172,890 - 5.2952x(flow) + 0.0031x(flow)^2$			$23,620 - 0.4223x(flow) + 0.0003x(flow)^2$			$168,369 - 4.796x(flow) + 0.003x(flow)^2$			$23,620 - 0.4223x(flow) + 0.0003x(flow)^2$		

Large-Volume Gas Flotation Systems

Design Flow (bpd)	Water Access						Land Access					
	Capital Cost ($)			O&M Cost ($/yr)			Capital Cost ($)			O&M Cost ($/yr)		
	Design	Calculated	% Error	Design	Calculate	% Error	Design	Calculated	% Error	Design	Calculated	% Error
10,000	381,094	373,772	-1.9%	42,237	41,613	-1.5%	366,289	359,471	-1.9%	42,237	41,613	-1.5%
15,000	405,633	405,413	-0.1%	44,353	44,311	-0.1%	389,253	388,940	-0.1%	44,353	44,311	-0.1%
25,000	464,664	468,695	+0.9%	49,311	49,709	+0.8%	443,874	447,879	+0.9%	49,311	49,709	+0.8%
40,000	555,990	563,617	+1.4%	57,191	57,805	+1.1%	529,355	536,288	+1.3%	57,192	57,805	+1.1%
80,000	820,861	816,744	-0.5%	79,741	79,396	-0.4%	775,852	772,044	-0.5%	79,741	79,396	-0.4%
Cost Equation	310,491 + 6.328x(flow)			36,215 + 0.54x(flow)			300,532 + 5.894x(flow)			36,215 + 0.54x(flow)		

then calculated by adding the annualized capital cost and the O&M cost for each flow. Total annual cost equations were then developed by regression analysis, and plotted against the flows. Figures XI-1 and XI-2 show the cut-off flow for produced water injection at facilities with water and land access, respectively.

The cut-off flow is the flow rate at which total annual costs for small- and for medium/large-volume facilities are the same. This means that it would be more economical for facilities with flows less than or equal to the cut-off to install additional storage capacity and dispose of the produced water at a commercial facility, while for the remaining facilities, injection or treatment onsite would be more economical.

For the injection treatment option, the cut-off flow was found to be 108.4 bpd and 70.5 bpd for facilities with water- and land-access, respectively. Out of the 216 facilities, 23% of the produced water dischargers are small-volume. For the treatment option based on gas flotation, the cut-off flow was found to be 70.5 bpd and 76.5 bpd for facilities with water- and land-access, respectively.[6] Out of the 216 facilities, 23% of produced water dischargers are small-volume.

3.5 Granular Media vs. Cartridge Filtration

Granular media filtration is an alternative pretreatment to injection. This technology is used at oil and gas facilities to reduce the TSS in produced water prior to discharge or injection. However, other less costly filtration systems such as cartridge filtration are available for coastal operations which have relatively low average flows. Both granular media and cartridge filtration technologies have been successfully demonstrated, proven, and are widely used.

As part of this rulemaking, EPA investigated the economic feasibility of using granular media vs. cartridge filtration systems as pretreatment to injection of produced water by comparing the capital and O&M costs of both treatment systems for various produced water flows. The cost comparison analysis, performed over the next 10 years, showed that for produced water discharges greater than 64,000 bpd, granular media filtration is more economical than cartridge filtration as pretreatment to injection in the coastal regions.

In 1989, Walk, Haydel developed costs for the injection of produced water using granular media filtration as pretreatment, as part of an economic analysis for produced water discharges in Louisiana.[11]

FIGURE XI-1
CUT-OFF FLOW ANALYSIS FOR INJECTION AT COASTAL PRODUCTION FACILITIES IN LOUISIANA

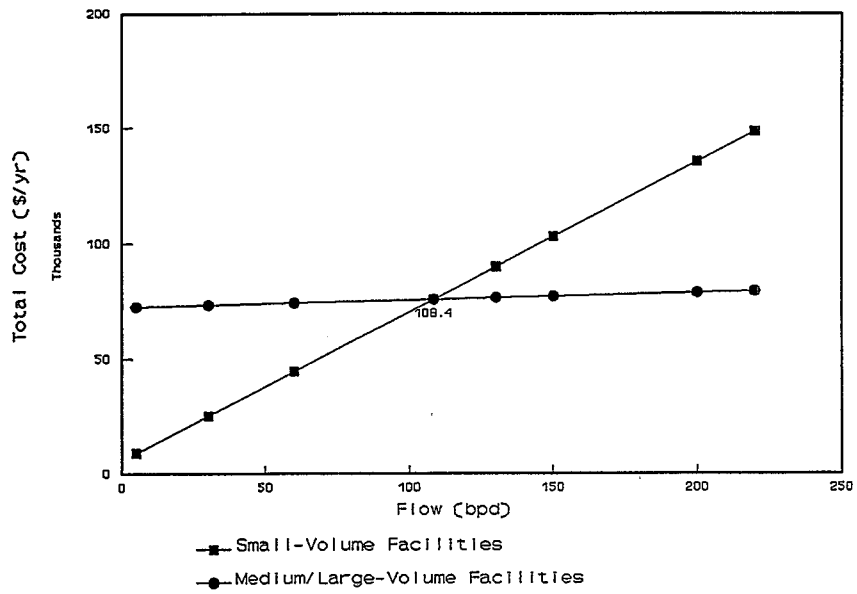
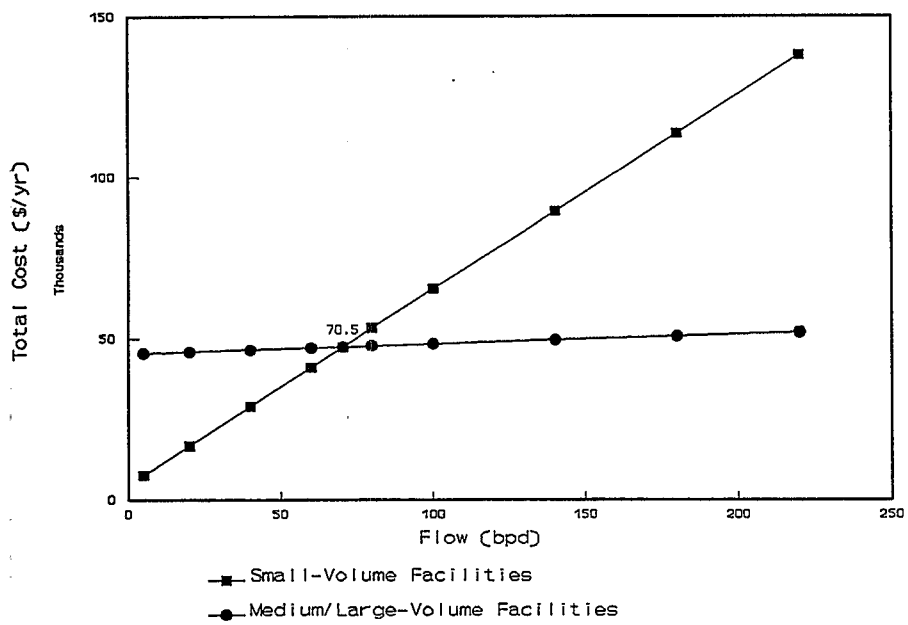


FIGURE XI-2
CUT-OFF FLOW ANALYSIS FOR INJECTION AT COASTAL PRODUCTION FACILITIES WITH LAND ACCESS



In their cost estimating effort, Walk-Haydel developed a capital cost equation for the surface equipment that best represented the relationship between cost and flow. The surface treatment system included dual upflow multimedia filters (one operating and one on standby), filter feed tank and pump, backwash pump and tank, a polymer feed system, and the injection pumps. Not included in surface equipment capital cost in the Walk-Haydel report is the injection well cost, pipeline to injection well, and a retrofit cost. The O&M cost (which includes labor, fuel consumption, maintenance materials, chemicals use, and any additional operating expenses) was estimated as representing 6.05% of the surface equipment total capital cost.

The second set of capital and O&M cost equations were developed for cartridge filtration systems for two facilities in Louisiana that generate over 100,000 bpd of produced water. These costs are based on the same assumptions as described in Section 3.2.1, excluding retrofit, pipeline, injection well costs, and well backwash cost.[17]

Total annual costs were calculated for both treatment systems using a capital recovery factor of 0.1627. A comparison of the total annual costs for both granular media filtration and cartridge filtration showed that for a system with produced water flows greater than 64,000 bpd, granular filtration is more economical than cartridge filtration as pretreatment to injection. There is only one facility in the Gulf of Mexico coastal area that would benefit economically from installing granular filtration as pretreatment to injection. This facility currently discharges in the coastal area 144,000 bpd of produced water generated offshore. Although this analysis showed that it would be more economical for one facility to use granular media filtration instead of cartridge filtration as pretreatment to injection, for reasons of being consistent and conservative EPA projected the economic impact of injection for this operator based on the cartridge filtration cost estimates.

3.6 Centralized Treatment Systems

Directing discharges to centralized treatment systems within the same field and the same company is an alternative that can provide savings both in the form of capital investment and in the annual operating and maintenance costs. Therefore, a cost comparison analysis was performed for each treatment option to determine which production facilities would benefit economically from centralized onsite injection and gas flotation systems. Centralized systems were considered for medium/large-volume facilities within the same field because piping costs increase significantly with increasing distance. Small-volume facilities were not included in this analysis because they transport produced water to commercial

facilities for injection, under all treatment scenarios. Also, centralized systems were only considered for production facilities within the same company because financial agreements between companies are difficult to predict.

The pipeline distance to a centralized treatment system was estimated based on the producing field dimensions. Field dimensions were estimated from oil and gas maps. The pipeline distance was then assumed to be one-half of the longest dimension for all production facilities within one field and owned by the same operator.

For the zero discharge by injection option, a total of 46 of the 216 production facilities in both Louisiana and Texas were shown to economically benefit from centralized injection systems. For the gas flotation option, a total of 36 of the 216 production facilities in both Louisiana and Texas were shown to economically benefit from centralized gas flotation treatment systems. As shown in Table XI-11 in Section 3.7.3, the total capital cost for medium/large-volume facilities with centralized injection system in Louisiana and Texas was estimated to be $78,767,247. Without the centralized treatment, the total capital cost for injection in both Louisiana and Texas was estimated to be $78,804,787, which only represents an increase of $37,540 (0.04%) over the centralized treatment scenario. The total O&M cost for medium/large-volume injection systems in Louisiana and Texas with centralization was estimated to be $15,750,278/yr. Without the centralized treatment, the total O&M cost for injection in both Louisiana and Texas was estimated to be $16,366,349/yr, which only represents an increase of 4% over the centralized treatment. EPA's cost analysis included costs with centralization.

Appendix XI-2 presents an example calculation of the centralized facilities treatment costs.

3.7 Gulf of Mexico Compliance Costs and Pollutant Reductions

3.7.1 Compliance Costs for Existing Facilities

Given the cost equations, actual volumes of produced water discharges were used to determine facility-specific costs. Capital and O&M costs for the treatment technology options for the Gulf of Mexico were estimated by totaling the costs calculated for each existing production facility in Louisiana and Texas that will continue to discharge after August 1, 1996. This date was selected as a reference point because this rulemaking effort is scheduled to be final in July 1996.

3.7.2 Compliance Costs for New Source Facilities

Capital and O&M costs were also estimated for the six new sources of produced water discharges in the Gulf of Mexico (see Section IV for new source projections). EPA determined that there will be a total of four new source facilities with water access and two with land access.[17] Of the four facilities with water access, one is classified as small-volume with an average produced water flow of 35.5 bpd and three are classified as medium/large-volume, each with and average produced water flow of 3,355 bpd.[17] Of the two facilities with land access, one is classified as small-volume with an average produced water flow of 30.6 bpd and one is classified as a medium/large-volume with an average produced water flow of 838 bpd.[18]

Small-volume facilities will incur capital and O&M costs associated with transportation and disposal of produced water to commercial disposal facilities (see Section 3.1).

Medium/large-volume facilities will incur capital and O&M costs associated with onsite treatment and disposal by injection or discharge (see Section 3.2). Capital and O&M costs for all new source facilities were developed using the same assumptions presented in Section 3.2 for both treatment technologies except for the type of engines and the cost of the injection well. For new sources, the cost of the injection well was assumed to be that of a newly drilled well for both water- and land-access facilities. All medium/large-volume treatment systems are equipped with electric motors.[6] The electric power required to operate the additional technology will be provided by natural gas driver generators. The generators are assumed an integral part of the design of new production facilities and will have sufficient capacity to also handle the produced water technology options. Therefore, additional costs for generators are not included for new sources.

3.7.3 Total Gulf of Mexico Compliance Costs and Pollutant Reductions

The incremental pollutant removals associated with the treatment technologies were calculated as the difference between the effluent levels after treatment by the technology options (injection and gas flotation) and the level associated with a typical BPT treatment (settling or skim tank). That is, pollutant removals by option were calculated by multiplying the average annual produced water flow rate for each facility type (water- or land-access) by the difference in pollutant concentrations in BPT effluent and each option effluent concentrations. Pollutant removals are expressed in pounds per year.

Table XI-10 presents the produced water pollutant loadings following BPT-level treatment and

TABLE XI-10
POLLUTANT LOADING CHARACTERIZATION - PRODUCED WATER
GULF OF MEXICO

Pollutant Groups	Existing Sources (lb/yr)		New Sources (lb/yr)	
	BPT-Level	Improved Gas Flotation	BPT-Level	Improved Gas Flotation
Conventional	11,641,571	3,348,174	261,014	74,617
Priority Organics	555,396	194,753	12,452	4,340
Priority Metals	134,438	97,288	3,014	2,168
Non-Conventionals	4,294,469,209	4,292,223,683	96,164,172	95,534,066
Total Pollutants	4,306,800,602	4,295,863,898	96,440,652	95,615,191

improved gas flotation level treatment. All loadings resulting from zero discharge are 0 lbs/yr. Total pollutant loadings represent the sum of individual analyte loadings. The values presented in Table XI-10 were obtained from the produced water characterization data presented in Section VIII.5.2.

The costs and the pollutant reductions for zero discharge by injection at existing and new source facilities in the Gulf of Mexico region are summarized in Table XI-11. The costs and the pollutant reductions for treatment by gas flotation at existing and new source facilities in the Gulf of Mexico region are summarized in Table XI-12.

4.0 COMPLIANCE COST METHODOLOGY FOR COOK INLET

Cook Inlet oil and gas are produced from 15 platforms. Currently, only 13 platforms are producing oil and gas. Two platforms are shut-in, and only one platform is scheduled to be brought back into production.[22] Nine of the 15 platforms pipe the production fluids (oil, gas, and water) to one of three shore-based facilities for separation and treatment. Produced water from the three shore-based facilities is discharged to Cook Inlet after treatment. The remaining five platforms separate and treat the production fluids at the platform. Produced water from each of the five platforms is discharged directly overboard after treatment. Because such facility-specific information is available, cost equations were not necessary in estimating costs for Cook Inlet operations. Capital and O&M costs were estimated specifically for each discharging facility.

Three technology options were considered and evaluated for the control of produced water

TABLE XI-11
INJECTION COSTS AND POLLUTANT REMOVALS - GULF OF MEXICO

	Existing Facilities[6]					New Sources[18]				
	No. Facilities	Total PW Flow (bpd)	Capital Cost (1992 $)	O&M Costs (1992 $/yr)	Pollutant Removal (lb/yr)	No. Facilities	Total PW Flow (bpd)	Capital Cost (1992 $)	O&M Cost (1992 $/yr)	Pollutant Removal (lb/yr)
SMALL-VOLUME FACILITIES										
Water-access	12	426	572,891	253,449	3,749,413	1	35.5	40,607	21,121	312,117
Land-access	38	1,033	1,083,380	625,895	9,091,887	1	30.6	28,510	18,541	269,036
Total	50	1,459	1,656,271	879,344	12,841,300	2	66.1	69,117	39,662	581,153
MEDIUM/LARGE-VOLUME FACILITIES										
Water-access	78	415,493	62,576,229	12,433,046	3,656,936,325	3	10,065	1,431,696	309,804	88,491,778
Land-access	88	72,285	16,191,018	3,317,232	636,212,023	1	838	229,074	43,520	7,367,721
Total	166	487,778	78,767,247	15,750,278	4,293,148,348	4	10,903	1,660,770	353,324	95,859,499
TOTAL FOR THE GULF OF MEXICO										
Water-access	90	415,919	63,149,120	12,686,495	3,660,685,738	4	10,100.5	1,472,303	330,925	88,803,895
Land-access	126	73,318	17,274,398	3,943,127	645,303,910	2	868.6	257,584	62,061	7,636,757
Grand Total	**216**	**489,237**	**80,423,518**	**16,629,622**	**4,305,989,648**	**6**	**10,969.1**	**1,729,887**	**392,986**	**96,440,652**

TABLE XI-12
GAS FLOTATION COSTS AND POLLUTANT REMOVALS - GULF OF MEXICO

	Existing Sources[6]					New Sources[18]				
	No. Facilities	Total PW Flow (bpd)	Capital Cost (1992 $)	O&M Costs (1992 $/yr)	Pollutant Removal (lb/yr)	No. Facilities	Total PW Flow (bpd)	Capital Cost (1992 $)	O&M Cost (1992 $/yr)	Pollutant Removal (lb/yr)
SMALL-VOLUME FACILITIES										
Water-access	9	179	322,478	106,496	4,001	1	35.5	40,607	21,121	312,451
Land-access	41	1,254	1,168,910	759,799	18,027	1	30.6	28,510	18,541	269,324
Total	50	1,433	1,491,388	866,295	32,028	2	66.1	69,117	39,662	581,775
MEDIUM/LARGE-VOLUME FACILITIES										
Water-access	81	415,740	19,911,896	2,031,065	9,291,964	3	10,065	675,600	84,450	224,957
Land-access	85	72,064	15,380,407	1,745,419	1,610,661	1	838	169,030	23,703	18,730
Total	166	487,804	35,292,303	3,776,484	10,874,989	4	10,903	844,630	108,153	243,687
TOTAL FOR THE GULF OF MEXICO										
Water-access	90	415,919	20,234,374	2,137,561	9,295,965	4	10,100.5	716,207	105,571	537,408
Land-access	126	73,318	16,549,317	2,505,218	1,638,688	2	868.6	197,540	42,244	288,054
Grand Total	216	489,237	36,783,691	4,642,779	10,934,653	6	10,969.1	913,747	147,815	825,462

discharges in Cook Inlet: BPT, injection, and improved gas flotation. Costs for each option were developed separately for the three shore-based facilities and for the five platforms that discharge overboard. The following sections summarize the assumptions and present the regulatory compliance costs estimated for injection and improved gas flotation for each discharging production facility. No costs are attributed to BPT because this is equivalent to current practice.

4.1 INJECTION

The control technology for the injection option in Cook Inlet is treatment and injection of produced water into producing formations as part of the waterflood operations or for disposal. Seawater is currently used for the waterflooding operations. For platforms that currently inject seawater for waterflooding, produced water will replace seawater. Therefore, the injection option includes the costs of piping produced water back to platforms for waterflooding. The pipeline costs represent the greatest cost contributor, i.e., 75% of the total cost, for the injection option.

A review of industry concerns regarding the technical feasibility of replacing seawater with produced water for waterflooding concluded that injection of produced water is technically feasible under proper operating conditions.[28] To meet these conditions, produced water must be pretreated for oil and grease and total suspended solids (TSS) removal, and chemicals such as biocides and scale inhibitors must be continuously added to the injection system.

The injection treatment process consists of gas flotation, granular media filtration, and injection. The estimated capital and O&M costs are the costs for additional equipment beyond what is currently available at each discharging facility or platform. Injection at the platform is the only option available to operators in Cook Inlet because there are no geological famations beneath the onshore treatment facilities capable of accepting the volumes of produced water generated. Table XI-13 identifies currently available treatment technologies at each production facility. The information shown in Table XI-13 was used to determine the additional equipment that would be required for the injection process for each production facility that discharges produced water directly to Cook Inlet. Based on costing information submitted by operators in Cook Inlet and the EPA Questionnaire, capital and O&M costs were estimated for the eight individual dischargers.[24,25]

4.1.1 Capital Costs

For the three shore-based facilities, capital costs include costs for additional equipment needed

TABLE XI-13

PRODUCED WATER TREATMENT EQUIPMENT AVAILABLE AT EACH DISCHARGING FACILITY IN COOK INLET[23]

Discharging Facility or Platform	Available Treatment Equipment For Produced Water			
	Gas Flotation	Filtration	Pipeline to Platform	Injection Equipment
Trading Bay[a]	Yes	Yes	No	Yes
Granite Point[a]	No	No	Yes	No
East Foreland[a]	No	Yes	No	Yes
Dillon[b]	No	Yes	--	Yes
Anna[b]	No	Yes	--	Yes
Baker[b]	No	Yes	--	Yes
Bruce[b]	No	Yes	--	No
Tyonek[b]	Yes	No	--	No

[a] Shore-based treatment facility
[b] Platform

at the shore-based facility plus the costs for modifications at the platforms where injection will take place. Total estimated capital costs include facility modification costs, equipment installation costs, additional costs for engineering design, contingencies, insurance and bonding, pipeline costs (only for shore-based facilities), and platform modifications that include retrofitting the platforms to accommodate additional treatment equipment and injection systems. Table XI-14 presents the estimated total capital costs to inject produced water for the three shore-based facilities and for the five platforms that discharge overboard.

The Trading Bay production facility (TBPF) which receives production fluids for separation and treatment from five platforms, currently has gas flotation units. Produced water will replace seawater for waterflooding at three platforms (King Salmon, Grayling, and Dolly Varden) that currently waterflood. These platforms have filtration and injection equipment. The three platforms currently inject a total of 124,700 bpd of seawater.[31] The total volume of produced water currently treated at the Trading Bay facility is an average of 121,243 bpd. Since the amount of produced water to be injected is less than the amount of seawater currently used in waterflooding operations, all produced water can be injected via waterflooding. The assumptions used to develop the TBPF modification capital costs are as follows

TABLE XI-14
CAPITAL AND O&M COSTS(1992 Dollars) FOR INJECTION OF PRODUCED WATER IN COOK INLET[23]

Category	Name of Discharging Facilities								Grand Total
	Trading Bay[a]	Granite Pt.[a]	E. Foreland[a]	Anna[b]	Dillon[b]	Bruce[b]	Baker[b]	Tyonek[b]	
1. Capital Cost ($)									
Installed Equipment[c]	8,986,660	1,622,140	4,997,404	1,084,118	1,192,535	1,002,332	849,348	1,182,586	20,917,123
Main Equipment Bldg.	296,612	296,612	296,612	0	0	0	0	0	889,836
Engineering (10%)	928,327	191,875	529,402	121,012	135,213	113,073	91,655	148,378	2,258,935
Contingency (15%)	1,392,491	287,813	794,102	181,518	202,820	169,609	137,482	222,567	3,388,402
Ins.-Bonding (4%)	371,331	76,750	211,761	48,405	54,085	45,229	36,662	59,351	903,574
Pipeline	30,199,454	0	13,938,091	0	0	0	0	0	44,137,545
Platform Modifications	2,928,135	964,882	976,045	126,000	159,600	67,200	67,200	240,000	5,529,062
Injection Equipment	0	64,192	0	0	0	61,194	0	61,194	186,580
Injection Well	0	1,350,000	0	0	0	2,394,346	0	2,394,346	6,138,692
Total Capital Cost	45,103,010	4,854,264	21,743,417	1,561,053	1,744,253	3,852,983	1,182,347	4,308,422	**84,349,749**
2. O&M Cost ($/yr)	6,231,081	119,450	2,256,362	180,708	246,048	152,600	123,090	198,144	**9,507,483**

[a] Shore-based treatment facility
[b] Platform
[c] The installed equipment cost includes a 15% factor for piping and instrumentation and a geographic area multiplier to account for equipment transportation and installation cost.

(for details see Appendix XI-5):

- **Shipping Pumps:** Four shipping pumps were costed, one for each pipeline and one spare. Each pump is rated for 1460 gpm at 700 psig with 1000 hp motor. The pump costs which were presented in 1993 dollars, were adjusted for 1992 dollars by the ENR-CCI ratio of 4985/5210.[25]

- **Booster Pumps:** Three booster pumps were costed, one for each pipeline. Booster pumps are required to pump the water from the storage tank to 150 psi to satisfy the net positive suction head (NPSH) of the shipping pumps. Each pump is rated for 2120 gpm at 150 psig with a 300 hp motor. The pump costs which were presented in 1993 dollars, were adjusted for 1992 dollars by the ENR-CCI ratio of 4985/5210.[25]

- **Motors:** All motors are electric driven motors. Electricity for these motors is supplied by natural gas driven generator. The cost of the power generation equipment is included, as provided by industry.[25]

- **Storage Tanks:** Two 15,000 bbl storage tanks were costed. These tanks were sized and costed by industry. The storage tanks costs which were presented in 1993 dollars, were adjusted for 1992 dollars by the ENR-CCI ratio of 4985/5210.[25]

- **Pig Launcher:** Three pig launchers were costed, one for each pipeline. Each pig launcher is 8 inch standard 600 ANSI. The costs for the pig launchers, which were presented in 1993 dollars, were adjusted for 1992 dollars by the ENR-CCI ratio of 4985/5210.[25]

- **Piping and Instrumentation:** Piping and instrumentation costs were assumed to be 15% of the equipment purchase cost. This cost includes any additional valves, fittings, piping, cables, conduits, instrumentation, and instrumentation wiring.[16]

- **Geographic Area Multiplier:** Because the equipment purchase costs represent Gulf of Mexico delivered equipment, a geographic area multiplier for Cook Inlet of 2.0 was included.[23]

- **Installation Cost:** Equipment installation costs were set equal to the equipment capital cost.[23]

- **Equipment Building:** The main equipment building is to house and protect the treatment equipment from the adverse weather conditions in Cook Inlet.[25]

- **Additional Costs (Engineering, Contingency, and Insurance-Bonding Fees):** These fees were added to the equipment purchase and installation costs to develop actual capital costs. These fees include all engineering design costs (10%), administrative costs (4%), and any incidental costs incurred in the process of purchasing and installing the equipment (15%).

- **Pipeline Cost:** Pipeline cost estimates include three 6.5-miles pipelines of 8-inch diameter pipe. These pipeline costs include pipeline and riser material cost, the cost to lay the pipeline, mobilization/demobilization costs, and project management. The pipeline costs which were presented in 1993 dollars, were adjusted for 1992 dollars the

ENR-CCI ratio of 4985/5210.[25]

- **Platform Modification Cost:** The platform modification costs are comprised of retrofitting each of the three platforms to accommodate the return pipeline to the existing injection system (pipeline installation, pig receiver, and replumbing existing piping). These costs which were presented in 1993 dollars were adjusted to 1992 dollars by the ENR-CCI ratio of 4985/5210. In addition, costs for contract services were included.

The Granite Point onshore treatment facility currently has bulk separation and skim tanks to treat produced water before it is piped to the Spark platform for discharge. Add-on equipment includes gas flotation and granular filtration. Pipeline for produced water already exists from Granite Point to the Spark platform. Thus, costs for a pipeline and the associated equipment (storage tanks, booster pumps, shipping pumps, pig launcher and pig receiver) were not included for this facility. The operator indicated that plans exist for future natural gas production at the Spark platform which is currently shut-in.[22] Therefore, injection of produced water at this platform will be for disposal rather than for waterflood. Since there are no waterflooding operations at the Spark platform, injection pumps are required. It was assumed that existing service wells can be recompleted for injection. Platform modification costs include the costs for connecting the produced water return pipeline to the injection system, for installing manifolds and platform piping to injection equipment, and for installing injection equipment.

The East Foreland facility currently treats produced water by plate coalescers. Add-on equipment includes gas flotation for oil and grease removal, and all the auxiliary equipment required for transporting produced water back to platform for injection: storage tank, booster pump, shipping pumps, and pig launcher. Produced water will be treated for TSS at platform SWEPI "C" were multi-media filtration equipment exists. Pipeline was costed to go from the E. Foreland facility back to platform "C" for a distance of nine miles. Platform modification costs include the costs for pig receiver, for connecting the produced water return pipeline to the platform, and for installing manifolds and platform piping to the existing filtration and injection equipment.

Of the five platforms that currently treat and discharge produced water overboard, three (Anna, Baker, and Dillon) inject seawater for waterflooding.[23] For these platforms, the only additional treatment cost is for gas flotation. The Bruce platform ceased waterflooding operations in 1983 due to overflooding the formation.[26] Since injection of produced water for waterflooding is not a technologically feasible option, it was assumed that produced water at this platform will be for disposal into a more shallow formation. Because filtration equipment is still available on the Bruce platform, it can be used for pretreatment to injection for disposal. For the Bruce platform, capital cost includes the cost of gas

flotation, injection equipment, and injection wells. The Tyonek platform is a gas-only platform and waterflooding is not currently practiced. The current treatment system for produced water on the Tyonek includes gas flotation. The modification costs for this platform includes the cost of filtration equipment, injection pumps, and injection wells. Produced water on the Tyonek platform will be injected for disposal. The assumptions used to develop the platform modification capital costs are as follows (for details see Appendix XI-5):

- **Materials and Equipment:** Gas flotation and/or granular media filtration equipment, and injection pumps were costed for each platform based on additional equipment required for injection, as determined from Table XI-12.[25] Injection pumps were sized and costed from information obtained from vendors.[10]

- **Piping and Instrumentation:** Piping and instrumentation costs were assumed to be 15% of the equipment purchase cost. This cost includes any additional valves, fittings, piping, cables, conduits, instrumentation, and instrumentation wiring.[16]

- **Geographic Area Multiplier:** Because the equipment purchase costs represent Gulf of Mexico delivered equipment, a geographic area multiplier for Cook Inlet of 2.0 was included.[23]

- **Installation Cost:** An installation factor of 2.5 times the equipment capital cost was applied for equipment installation costs.[23]

- **Additional Costs (Engineering, Contingency, and Insurance-Bonding Fees):** These fees were added to the equipment purchase and installation costs to develop actual capital costs. These fees include all engineering design costs (10%), administrative costs (4%), and any incidental costs incurred in the process of purchasing and installing the equipment (15%).

- **Platform Modification Cost:** The cost of additional platform space was calculated based on equipment area requirements and a cost of $600 per square foot in the form of a cantilever deck.[27]

- **Injection Wells:** One disposal well and a spare were costed for platforms where waterflooding is not currently practiced. Each well has a capacity of 6,000 bpd.[23] The cost of drilling an injection well was derived from data in the EPA Questionnaire to be $1,197,173 (see Section X).

4.1.2 O&M Costs

The annual operating and maintenance cost was estimated to be ten percent (10%) of the total capital cost. Typically, the operating and maintenance costs include: labor, polymer and/or flocculation enhancement chemicals, fuel cost, and equipment maintenance and replacement costs. In addition, costs for chemical treatment for injection such as scale inhibitors and biocides, and injection well maintenance

costs were included for each platform where produced water has been proposed for injection. These costs were obtained from the EPA Questionnaire from facilities that currently inject produced water for waterflooding.[24] A statistical analysis of the chemical usage and produced water injection rates indicated that dosages for scale inhibitors and biocides are on the average 0.00221 gal/bbl and 0.00181 gal/bbl, respectively.[23] Table XI-15 lists the O&M costs that were estimated for injection of produced water for each discharging facility in Cook Inlet. Total O&M costs for each production facility in Cook Inlet that discharges produced water are presented in Table XI-14.

4.2 IMPROVED GAS FLOTATION

The control technology for the improved gas flotation option is treatment and discharge of produced water to Cook Inlet. 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 to achieve the stricter effluent limitations that are proposed based on improved gas flotation. Table XI-13 identifies currently available treatment technologies at each production facility. The information shown in Table XI-13 was used to determine the additional equipment that would be required for each production facility that discharges produced water directly to Cook Inlet.

4.2.1 Capital Cost

Capital costs have been estimated for gas flotation treatment for those production facilities that currently do not have gas flotation. Capital costs for facilities that discharge produced water are presented in Table XI-16. The assumptions used to develop the capital costs for gas flotation are as follows (for details see Appendix XI-5):

- **Materials and Equipment:** The equipment purchase cost for all production facilities includes: gas flotation skid-mounted, complete electrical systems, oil and water outlets brought to the edge of the skid, and sufficient instrumentation for proper operation. The size of the equipment varies with flow and the cost of the equipment is the same as the design equipment cost for the Gulf of Mexico (see Section 3.2.2).

- **Piping and Instrumentation:** Piping and instrumentation costs were assumed to be 15% of the equipment purchase cost. This cost includes any additional valves, fittings, piping, cables, conduits, instrumentation, and instrumentation wiring (see Section 3.2.2).

- **Geographic Area Multiplier:** Because the equipment purchase costs represent Gulf of Mexico delivered equipment, a geographic area multiplier for Cook Inlet of 2.0 was included.[23]

TABLE XI-15

ESTIMATED O&M COSTS(1992 Dollars) FOR INJECTION OF PRODUCED WATER IN COOK INLET[23]

Category	Name of Discharging Facilities								Grand Total
	Trading Bay[a]	Granite Pt.[a]	E. Foreland[a]	Anna[b]	Dillon[b]	Bruce[b]	Baker[b]	Tyonek[b]	
Standard O&M[c]	4,510,301	102,907	2,174,342	156,105	174,425	145,864	118,235	191,408	7,573,587
Scale Inhibitor	713,941	5,319	34,125	8,865	29,551	1,005	177	1,005	793,988
Biocide	908,895	6,772	43,443	11,286	37,620	1,279	226	1,279	1,010,800
Well Workover	97,944	4,452	4,452	4,452	4,452	4,452	4,452	4,452	129,108
Total O&M Cost	6,231,081	119,450	2,256,362	180,708	246,048	152,600	123,090	198,144	**9,507,483**

[a] Shore-based treatment facility
[b] Platform
[c] The standard O&M cost is 10% of the total capital cost and includes labor, flocculation enhancement chemicals, fuel cost, and equipment maintenance and replacement costs.

TABLE XI-16

CAPITAL AND O&M COSTS(1992 Dollars) FOR GAS FLOTATION IN COOK INLET[23]

Category	Name of Discharging Facilities or Platforms								Grand Total
	Trading Bay[a]	Granite Pt.[a]	E. Foreland[a]	Anna[b]	Dillon[b]	Bruce[b]	Baker[b]	Tyonek[b]	
1. Capital Cost ($)									
Installed Equipment[c]	0	619,496	681,448	1,084,118	1,192,535	849,348	849,348	0	5,276,293
Main Equipment Bldg.	0	296,612	296,612	0	0	0	0	0	593,224
Engineering (10%)	0	91,611	97,806	121,012	135,213	91,655	91,655	0	628,952
Contingency (15%)	0	137,416	146,709	181,518	202,820	137,482	137,482	0	943,427
Ins.-Bonding (4%)	0	36,644	39,122	48,405	54,085	36,662	36,662	0	251,580
Platform Modifications	0	0	0	126,000	159,600	67,200	67,200	0	420,000
Total Capital Cost	0	1,181,779	1,261,697	1,561,052	1,744,253	1,182,347	1,182,347	0	**8,113,476**
2. O&M Cost ($/yr)	223,762	118,178	126,170	156,105	174,425	118,235	118,235	0	**1,035,110**

[a] Shore-based treatment facility
[b] Platform
[c] The installed equipment cost includes a 15% factor for piping and instrumentation and a geographic area multiplier to account for equipment transportation and installation cost.

- **Installation Cost:** An installation factor of twice the equipment purchase cost was used for the shore-based facilities and a factor of 2.5 times the equipment capital cost was used for platforms.[23]

- **Additional Costs (Engineering, Contingency, and Insurance-Bonding Fees):** These fees were added to the equipment purchase and installation costs to develop actual capital costs. These fees include all engineering design costs (10%), administrative costs (4%), and any incidental costs incurred in the process of purchasing and installing the equipment (15%).

- **Platform Modification Cost:** The cost of additional platform space was calculated based on equipment area requirements and a cost of $600 per square foot in the form of a cantilever deck.[27]

4.2.2 O&M Cost

The annual operating and maintenance cost was estimated to be ten percent (10%) of the total capital cost. Typically, the operating and maintenance costs include: labor, polymer and/or flocculation enhancement chemicals, fuel cost, and equipment maintenance and replacement costs. Estimated O&M costs for each production facility in Cook Inlet that discharges produced water are presented in Table XI-16. Although the Trading Bay facility currently has gas flotation and therefore will not incur an additional capital cost for gas flotation, it will incur an additional O&M cost to comply with stricter effluent limitations based on improved operations of gas flotation. This cost was estimated to be 10% of the cost of a new gas flotation system.[23]

4.3 Total Cook Inlet Compliance Costs and Pollutant Reductions

The incremental pollutant removals associated with the treatment technologies were calculated as the difference between the effluent levels after treatment by the technology options (injection, gas flotation) and the level associated with a typical BPT treatment (gas flotation or gravity separation). That is, the pollutant removals were calculated by multiplying the annual average produced water flow rate for each treatment option by the difference in pollutant concentration in BPT effluent and the additional technology effluent concentrations.

Table XI-17 presents the produced water pollutant loadings following BPT-level treatment and improved gas flotation level treatment. Total pollutant loadings represent the sum of individual analyte loading. The values presented in Table XI-17 were obtained from the produced water characterization data presented in Section VIII.5.2. Based on individual estimates, the total incremental costs and the pollutant reductions for the two options considered to control discharges of produced water in Cook Inlet

TABLE XI-17

POLLUTANT LOADING CHARACTERIZATION - PRODUCED WATER
COOK INLET

Pollutant Groups	Existing Sources (lb/yr)		New Sources (lb/yr)	
	BPT-Level	Improved Gas Flotation	BPT-Level	Improved Gas Flotation
Conventional	1,760,281	915,021	0	0
Priority Organics	123,705	50,041	0	0
Priority Metals	60,003	27,934	0	0
Non-Conventionals	1,176,054,486	971,764	0	0
Total Pollutants	1,177,998,475	1,964,760	0	0

TABLE XI-18
COMPLIANCE COSTS AND POLLUTANT REDUCTIONS IN COOK INLET

Options	Average PW Volume (bpd)[a]	Number of Facilities	Capital Cost ($)	O&M Cost ($/yr)	Pollutant Reductions (lb/yr)
Injection All	133,982	8	84,349,749	9,507,483	3,459,182
Gas Flotation All	133,982	8	8,113,476	1,035,110	1,494,420

[a] This flow includes 2,650 bpd from Dillon, which is the volume of produced water reported prior to 1991.[30]

are summarized in Table XI-18. Costs and pollutant reductions were not developed for new sources because EPA determined that there will be no new sources in Cook Inlet following promulgation of this rule (see Section IV for a discussion of new source projections).

5.0 OPTION TOTAL COSTS AND POLLUTANT REMOVALS

An analysis of each regulatory option above current practice was conducted to determine:

- Incremental costs incurred by industry to comply with the regulation.
- Reduction of pollutants above current practice discharged to the surface waters.

The following sections present the analysis of each regulatory option for Cook Inlet, Texas, and Louisiana combined. No costs for the coastal industry located outside of these areas are incurred for these options because they are currently meeting zero discharge (see Section IV).

5.1 BAT AND NSPS INCREMENTAL COMPLIANCE COSTS

Table XI-1 presents the incremental compliance costs for the five regulatory options. The incremental compliance costs listed in Table XI-1 are equal to the capital and O&M costs for each given technology option because they are add-on technologies. For scenarios in which gas flotation systems are already in place (i.e., specific Cook Inlet platforms), the incremental cost is only the O&M cost associated with improved operation of existing technology. Option 1 incurs zero incremental costs because it sets all limitations equal to BPT.

The incremental costs for NSPS are also equal to the capital and O&M costs for add-on technology. No new sources are expected for Cook Inlet. Therefore, costs and pollutant reductions for new source facilities are predicted only for the Gulf of Mexico. Table XI-1 also presents the incremental compliance costs for new sources for two regulatory options.

5.2 BAT AND NSPS POLLUTANT REMOVALS

The incremental pollutant removals associated with existing and new source treatment technologies were determined by comparing the effluent levels after treatment by technology options (improved gas flotation or injection) with the effluent levels associated with a typical BPT treatment (gas flotation or gravity separation).

Spreadsheets were developed to calculate pollutant removals for the five treatment options on a regional basis using the average regional produced water flow and contaminant removal data. Existing and new source facilities pollutant removal quantities for each option were calculated by multiplying the annual average produced water flow rate for each region by the difference in pollutant concentrations in BPT effluent and technology options effluent concentrations.

Pollutant removals were determined for each regulatory option considered and are presented in Table XI-19 for existing and new source facilities.

TABLE XI-19

ANNUAL REGIONALIZED POLLUTANT REMOVALS FOR EXISTING AND NEW SOURCE FACILITIES
(lb/yr)

	Existing Sources			New Sources		
	Gulf of Mexico	Cook Inlet	Total	Gulf of Mexico	Cook Inlet	Total
Option 1	0	0	0	0	0	0
Option 2						
Conventionals	8,293,397	845,261	9,138,658	186,397	0	186,397
Priority Organics	360,643	69,959	430,602	8,112	0	8,112
Priority Metals	37,150	15,282	52,432	846	0	846
Other Non-Conventionals	2,245,518	563,918	2,809,436	630,106	0	630,106
Total	10,936,708	1,494,420	12,431,128	825,462	0	825,462
Option 3						
Conventionals	11,641,572	0	11,641,572	261,014	0	261,014
Priority Organics	555,396	0	555,396	12,452	0	12,452
Priority Metals	134,438	0	134,438	3,014	0	3,014
Other Non-Conventionals	4,294,469,201	0	4,293,658,243	96,164,172	0	96,164,172
Total	4,306,800,607	0	4,305,989,648	96,440,652	0	96,440,652
Option 4						
Conventionals	11,641,572	845,261	12,486,832	261,014	0	261,014
Priority Organics	555,396	69,959	625,355	12,452	0	12,452
Priority Metals	134,438	15,282	149,720	3,014	0	3,014
Other Non-Conventionals	4,294,469,201	563,918	4,295,033,119	96,164,172	0	96,164,172
Total	4,306,800,607	1,494,420	4,308,295,026	96,440,652	0	96,440,652
Option 5						
Conventionals	11,641,572	1,760,281	13,401,853	261,014	0	261,014
Priority Organics	555,396	123,705	679,101	12,452	0	12,452
Priority Metals	134,438	60,003	194,441	3,014	0	3,014
Other Non-Conventionals	4,294,469,201	1,176,054,522	5,470,523,723	96,164,172	0	96,164,172
Total	4,306,800,607	1,177,998,511	5,484,799,118	96,440,652	0	96,440,652

6.0 BCT COST TEST

The five options proposed for existing facilities were also evaluated according to the BCT cost reasonableness tests. The BCT cost test methodology for produced water is the same as that described in Section X.6.1. The pollutant parameters used in this analysis are total suspended solids (TSS) and oil and grease. Table XI-19 lists incremental costs and conventional pollutant removals for each regulatory option.

All of the produced water options considered for BCT regulation fail the BCT cost test except

for the BCT option equal to BPT. For Options 2 through 5, the ratio of cost of pollutant removal to pounds of pollutant removed (POTW Test) exceeds the POTW benchmark of $0.534 per pound (the 1986 benchmark of $0.46 per pound adjusted to 1992 dollars). Table XI-20 presents the BCT Cost Test Analysis.

TABLE XI-20

PRODUCED WATER BCT COST TEST ANALYSIS

Option	Conventional Pollutant Removals (lbs/yr)	Annual BCT/BAT Costs ($/yr)[29]	POTW Cost Ratio ($/lb)	Pass POTW?
Option 1	0	0	0	Yes
Option 2	9,138,658	12,371,872	1.35	No
Option 3	11,641,571	28,615,098	2.46	No
Option 4	12,486,833	30,862,336	2.47	No
Option 5	13,401,853	49,653,291	3.70	No

7.0 REFERENCES

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SECTION XII

COMPLIANCE COST AND POLLUTANT LOADING DETERMINATION-WELL TREATMENT, WORKOVER, AND COMPLETION FLUIDS

1.0 INTRODUCTION

This section presents the compliance costs and pollutant reductions for the regulatory options for treatment and disposal of well treatment, workover, and completion (TWC) fluids.

2.0 OPTIONS CONSIDERED AND SUMMARY COSTS

EPA has considered two options for the treatment of TWC fluids. These are:

Option 1: Limit the discharges equal to the existing BPT requirements of 72 mg/l daily maximum and 48 mg/l monthly average for concentrations of oil and grease, and include the requirement that no discharges are allowed in fresh waters of Texas and Louisiana.

Option 2: Limit the discharges equal to EPA's preferred option for produced waters.

In this section, no costs or pollutant reductions are presented for Option 1 because it represents no change from current limitations. Compliance costs and pollutant reductions for TWC fluids were developed for Option 2 for the same two options that were developed for produced water: while EPA's preferred option for produced waters is zero discharge everywhere except Cook Inlet, Alaska, where the preferred produced water control option is to meet limitations on oil and grease of 42 mg/l daily maximum and 29 mg/l monthly average, costs were also developed for TWC discharges following commingling with produced water and treatment by improved gas flotation. For TWC fluids, these options are referred to as Options 2a and 2b, respectively. As shown in Section XI.2 for produced water, discharges of TWC fluids under Option 2b would be required to meet limitations on oil and grease content of 42 mg/l daily maximum and 29 mg/l monthly average.

The cost and pollutant loadings analyses presented herein apply only to the Gulf of Mexico coastal area. For Cook Inlet operations, waste TWC fluids are currently commingled with produced water prior

to treatment and/or disposal, and thus costs for their treatment and disposal are already included in the costing of the produced water options.

Table XII-1 presents the results of the compliance cost analyses for Options 1, 2a, and 2b. Detailed spreadsheets containing the calculation of these estimates are included in Appendix XII-1.

TABLE XII-1

TOTAL ANNUAL COMPLIANCE COST ESTIMATES FOR TREATMENT, WORKOVER, AND COMPLETION FLUIDS[a] (1992$) (from Appendix XII-1)

Option		Fluid Type	Existing Sources	New Sources
1:	BPT limitations; zero discharge to fresh waters of TX and LA	All TWC Fluids	$0	$0
2a:	Zero discharge via injection or commercial disposal	Workover/Treatment	$449,344	$57,773
		Completion	$156,301	$21,059
		Total	**$605,645**	**$78,831**
2b:	Discharge via improved gas flotation or commercial disposal	Workover/Treatment	$438,814	$56,419
		Completion	$152,724	$20,577
		Total	**$591,538**	**$76,995**

[a] These costs are based only on coastal Gulf of Mexico data. Cook Inlet costs were determined to be zero for this analysis.

3.0 COMPLIANCE COST METHODOLOGY

The following sections describe the assumptions, data and methodology used to develop the cost estimates in Table XII-1.

3.1 GENERAL ASSUMPTIONS AND INPUT DATA

The technology basis assumed in the development of compliance cost estimates for TWC fluids is either commercial disposal or commingling of TWC fluids with produced water for onsite treatment and/or disposal. A statistical analysis of the responses to the 1993 Coastal Oil and Gas Questionnaire showed that 85% of the producing wells in the Gulf of Mexico coastal area that disposed of workover

and/or treatment fluids in 1992 did so by commingling the fluids with produced water.[1] Also, commingling of TWC fluids is an existing technology in Cook Inlet, Alaska.[2]

No additional capital expenses are included for handling TWC fluids under Options 2a and 2b. It is assumed that, since TWC operations are occasional occurrences (rather than continuous), all necessary tankage and equipment would be brought onsite at the time of the job as a matter of standard operations, and would be removed at the conclusion of the job. It is further assumed that, except in the case of fluids that would be captured for reuse or separate disposal after the job (e.g., oil-based fluids), TWC fluids can be left in the hole and brought up with the produced fluids when the well is brought back on-line, thus requiring no additional fluids management equipment to be purchased.[3] Thus, costs for onsite treatment and/or disposal of TWC fluids are based on operating and maintenance (O&M) costs previously developed for produced water in Section XI. Costs for offsite commercial disposal are based on information obtained directly from industry sources.

Several assumptions regarding the profile of production operations in the Gulf of Mexico coastal area were adopted from the produced water cost estimate analysis presented in Section XI and are listed below. In addition, per-well discharge volume data were obtained from a statistical analysis of the responses to the 1993 Coastal Oil and Gas Questionnaire.[1] These assumptions and data are also presented below.

3.1.1 Assumptions and Input Data Derived from the Results of the 1993 Coastal Questionnaire

- Annual Number of Existing Wells Discharging TWC Fluids: As described in Section IX.2.1, the numbers of existing wells currently discharging workover/treatment fluids and completion fluids were derived from the 1993 Questionnaire results and state Discharge Monitoring Report (DMR) data. The survey results indicate that in 1992, 219 wells discharged workover/treatment fluids and 209 wells discharged completion fluids.[1] A comparison of the number of wells in the survey to the number of wells for which DMR data are available revealed that the survey count of wells must be increased by a factor of 1.6 for an accurate count of existing wells.[4] Thus, the estimates of 219 wells discharging workover/treatment fluids and 209 wells discharging completion fluids were increased to 350 and 334, respectively.

- Annual Number of New Wells Discharging TWC Fluids: The number of new wells discharging TWC fluids was derived from 1993 survey data. The survey results indicate that 187 new production wells were drilled in 1992.[1] EPA determined that due to the existing prohibition of TWC fluid discharges to fresh water areas imposed by the EPA Region VI general permit (58 FR 49126), a proportion of the 187 new wells would not be affected by the proposed regulation. Data used to identify the population of coastal operators to be included in the 1993 survey were used to determine the proportion of new wells that would be located in fresh vs saline water areas. Table XII-2 lists the data and results of this analysis, and shows that approximately 76% of the wells in the coastal Gulf of Mexico region that were completed since 1990 are located in fresh water areas and 24% are located in saline water areas. The calculation of the number of wells located in saline water areas, and hence subject to the proposed regulations, is as follows:

(187 wells discharging TWC fluids in 1992) x (24% saline water areas) = 45 new source wells/year

TABLE XII-2

NUMBER OF WELLS LOCATED IN FRESH VS SALINE WATERS IN THE COASTAL GULF OF MEXICO REGION[1,a]

Size of Operator	Freshwater Areas	Saline Water Areas
Major	174	65
Small Independent	14	2
Other	287	80
Total	**475**	**147**

[a] The values in this table are the sum of the values in Tables 2, 6, and 7 in the source document, only for wells completed during or after 1990.[1]

- Percentage of Land- vs Water-Access Facilities: The data shown in Table IX-13 in Section IX.3.2 were obtained from the responses to the 1993 Coastal Questionnaire.[5] This table compares the number of responses to three survey questions that relate to facility location (i.e., over water or land) by asking whether they are accessible via truck or barge. Using these data, it was estimated that the percentage of water-access facilities is 65.6% and land-access facilities represent 34.4%. This assumption is used to distinguish which facilities will incur barge vs truck transportation costs for those facilities that must dispose of their TWC fluids commercially.

- Average Volume of TWC Fluids Discharged Per Well: The annual volumes of workover/treatment fluids and completion fluids discharged per well were reported in Section IX.2.1 as being 587 bbls and 209 bbls, respectively.[1]

3.1.2 Assumptions Adopted from the Produced Water Cost Estimate Methodology

- Percentage of Large vs Small Facilities: From the produced water costing analysis, two categories of facility size were developed, based on flow rate: 1) medium/large facilities that would employ onsite treatment technology, and 2) small facilities that would utilize commercial disposal. The methodology for determining these categories is discussed in Section XI. For both the zero-discharge via injection option and the discharge via improved gas flotation option, there are 50 small and 166 medium/large facilities. This translates to 23% small facilities and 77% medium/large facilities. In both TWC fluid option cost analyses, 77% of the identified discharging wells are assumed to utilize either injection (for Option 2a) or gas flotation (for Option 2b). Likewise, 23% of the identified wells are assumed to utilize commercial disposal in both Options 2a and 2b.

- Costs to Inject TWC Fluids: These costs were calculated from the O&M costs and volumes that were developed for injection of produced water at medium/large facilities, as presented in Section XI, Table XI-11. For water-access sites, the cost is $0.08/bbl, and for land-access sites, the cost is $0.15/bbl.

- Costs to Treat TWC Fluids with Gas Flotation: These costs were calculated from the O&M costs and volumes that were developed for gas flotation treatment of produced water at medium/large facilities, as presented in Section XI, Table XI-12. For water-access sites, the cost is $0.01/bbl, and for land-access sites, the cost is $0.09/bbl.

3.1.3 Additional Assumptions and Data

- Barge Capacity and Cost: Water-access facilities that were determined to utilize commercial disposal rather than onsite treatment and/or disposal were assumed to require a portion of a small-capacity (1,500 bbls) shale barge to transport the waste TWC fluids to a land-based commercial disposal facility.[6] These shale barges are divided into four equivalent and separate sections. The

cost for the use of a shale barge was derived by assuming that a portion of the barge would be dedicated to TWC fluids while other wastes would be transported in the remainder of the barge. Although it is recognized that TWC fluids would likely be mixed with other field wastes with comparable disposal costs, such as spent drilling fluid, this approach reflects the fraction of the barge cost attributable to the TWC volumes. Each 587-bbl volume of workover\treatment fluid would require one-half of a single barge's capacity (750 bbls). Each 209-bbl volume of completion fluid would require one-fourth of a barge (375 bbls). The transportation cost for a single barge and tug is $1,000 per round trip.[6] Therefore, the costs for barge transportation are estimated to be $500 per job for workover/treatment fluids, and $250 per job for completion fluids.

- Truck Capacity and Cost: Land-access facilities that were determined to utilize commercial disposal rather than onsite treatment and/or disposal were assumed to require 120-bbl capacity vacuum trucks to transport the waste TWC fluids to a land-based commercial disposal facility.[7] The assumed cost for a vacuum truck is $1.75/bbl.[7]

- Commercial Disposal Cost for TWC Fluids: The assumed cost for disposal of all TWC fluids is $8/bbl.[8] This cost was obtained from a commercial disposal company for completion fluids[8], and is applied to all TWC fluids based on the fact that completion and workover fluids are similar types of fluids and typically weigh nine pounds per gallon or more.

3.2 Compliance Cost Methodology

The spreadsheets in Appendix XII-1 were developed to calculate the compliance cost estimates for existing and new sources of TWC fluids. For each option and for each source category (existing or new), two spreadsheets were created: one for workover/treatment fluids and one for completion fluids. The input data (described in Section 3.1) applicable to each scenario are listed in each spreadsheet. Within each spreadsheet, two costs were calculated: treatment (either injection or gas flotation) costs at medium/large-volume facilities, and commercial disposal costs at small-volume facilities. The treatment costs, determined separately for water- and land-access facilities, consist of the following calculations:

- Number of workover/treatment or completion jobs per year
- Number of jobs injected or treated by gas flotation per year
- Total volume treated per year

- Treatment (injection or gas flotation) cost per year.

The commercial disposal costs, also determined for water- and land-access facilities, consist of the following calculations:

- Number of workover/treatment or completion jobs per year
- Number of jobs disposed commercially per year
- Total volume disposed commercially per year
- Transportation cost per year
- Commercial disposal cost per year
- Total transportation and disposal cost per year.

The total costs presented in Table XII-1 are the sum of the costs presented in Appendix XII-1.

4.0 POLLUTANT REDUCTIONS

The following sections describe the assumptions, data and methodology used to develop these pollutant reduction estimates.

4.1 GENERAL ASSUMPTIONS AND INPUT DATA

The concentration data for TWC fluids produced water presented in Table IX-7 in Section IX.2.2.3 are assumed to represent the characteristics of TWC fluids as they are currently discharged by commingling. Details of the development of these data are provided in Section IX.2.2.3. The concentration data for improved gas flotation presented in Table VIII-6 in Section VIII.5.2.1 describing produced water are assumed to represent the characteristics of TWC fluids following commingling and treatment with produced water. These data are used here because no data are available for TWC fluids treated by improved gas flotation. Furthermore, it is assumed that TWC fluids that can be commingled and treated without upsetting the treatment system have characteristics similar to produced water.

4.2 METHODOLOGY

The spreadsheets in Appendix XII-2 were developed to calculate the pollutant reduction estimates for existing and new sources of TWC fluids. For each option and for each source category (existing or new), two spreadsheets were created: one for workover/treatment fluids and one for completion fluids. The annual volumes discharged, injected, treated, or disposed in these spreadsheets are those calculated

in the corresponding compliance cost spreadsheets in Appendix XII-1.

The pollutant reductions due to the application of the zero-discharge option (Option 2a) are equivalent to the loadings due to current practice. As shown in the spreadsheets, the current-practice concentrations were multiplied by the volumes currently discharged, and the reductions were calculated by subtracting the treatment-level loadings (0 lbs in this case) from the current-level loadings. Table XII-3 presents the total TWC fluid loadings and reductions calculated for each source category (existing or new) and for each option. The loadings and reductions presented in Table XII-3 are the sum of the reductions presented in Appendix XII-2.

The pollutant reductions due to the application of the treat-and-discharge option (Option 2b) are the difference between the current loadings and the loadings resulting from improved gas flotation treatment. However, because it is assumed that 77% of the volume currently discharged will be treated and discharged under this option, while the remaining 23% is commercially disposed, the calculated pollutant reductions reflect the complete removal of 23% of the waste stream (i.e., a loading of 0 lbs for 23% of the volume, as in the zero-discharge option).

5.0 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 and treat-and-discharge options. The methodology for the BCT cost test is presented in Section X.6.1.

The compliance costs and pollutant reductions presented in Sections 3.0 and 4.0 are all considered to be incremental to BPT-level costs and reductions because they were based on costs and pollutant characteristics that are additional or supplemental to BPT-level treatment.

Table XII-4 presents the results of only the first part of the BCT cost test, the POTW cost ratio test, because both Options 2a and 2b fail this test.

TABLE XII-3

TOTAL ANNUAL POLLUTANT LOADINGS AND REDUCTIONS FOR TREATMENT, WORKOVER, AND COMPLETION FLUIDS[a]
(pounds/year)
(from Appendix XII-2)

Option		Pollutant Type	Existing Sources		New Sources	
			Loading	Reduction	Loading	Reduction
1:	BPT limitations; zero discharge to fresh waters of TX and LA	Conventionals	72,398	0	9,421	0
		Priority Pollutant Organics	417	0	54	0
		Priority Pollutant Metals	292	0	38	0
		Non-Conventionals	3,389,900	0	439,271	0
		Total	**3,463,007**	**0**	**448,785**	**0**
2a:	Zero discharge via injection or commercial disposal	Conventionals	0	72,398	0	9,421
		Priority Pollutant Organics	0	417	0	54
		Priority Pollutant Metals	0	292	0	38
		Non-Conventionals	0	3,389,900	0	439,271
		Total	**0**	**3,463,007**	**0**	**448,785**
2b:	Discharge via improved gas flotation or commercial disposal	Conventionals	3,966[b]	68,433	1,078[b]	8,905
		Priority Pollutant Organics	183[b]	218	50[b]	28
		Priority Pollutant Metals	55[b]	169	13[b]	22
		Non-Conventionals	1,423[b]	38,462	387[b]	5,005
		Total	**5,626[b]**	**107,282**	**1,530[b]**	**13,961**

[a]These loadings and reductions are based only on coastal Gulf of Mexico data. Cook Inlet loadings and reductions were determined to be zero for this analysis.
[b]These loadings are the product of the gas flotation effluent concentrations and 77% of the volume currently discharged. The remaining 23% of the volume is assumed to be commercially disposed under Option 2b, and thus contributes no loadings to the calculation (see Appendix XII-2 for detailed spreadsheets).

TABLE XII-4

BCT COST TEST FOR TREATMENT, WORKOVER, AND COMPLETIONS FLUIDS

Option		Conventional Pollutants Removed (lbs/yr)	Compliance Cost ($/yr)	POTW Cost Ratio ($/lb)	Pass? (Y/N)
1:	BPT limitations; zero discharge to fresh waters of TX and LA	0	0	0	Y
2a:	Zero discharge via injection or commercial disposal	72,397	605,645	8.37	N
2b:	Discharge via gas flotation or commercial disposal	68,433	591,538	8.64	N

6.0 REFERENCES

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SECTION XIII

COST AND POLLUTANT LOADING DETERMINATION - DECK DRAINAGE

1.0 INTRODUCTION

This section presents the compliance costs for the proposed regulatory options for treatment and disposal of deck drainage. For coastal operations in the Gulf of Mexico, EPA investigated deck drainage from drilling operations and production operations as two separate types of sources. This was due to the fact that Gulf Coast drilling and production operations can be two separate and distinct activities which may generate different volumes and have characteristically different pollutant contamination (e.g., only drilling operations experience contamination with drilling fluids). For Cook Inlet, however, drilling and production can occur simultaneously, therefore producing a combined deck drainage source as discussed later in this section.

2.0 OPTIONS CONSIDERED AND COSTS

The technology option considered for deck drainage was the capture of the first 500 bbls of a storm event, referred to as the "first flush", and setting the limitation for this volume equal to those for the major wastestreams that it can be commingled with. The two treatment and disposal technologies considered for the commingled deck drainage are zero discharge and improved gas flotation. The deck drainage volume that exceeds the 500 bbl volume would be subject to the current BPT limitation for deck drainage. The options are defined as follows:

Option 1) Discharge limitation is equal to the current BPT limitation requiring "no discharge of free oil."

Option 2) Capture of the first 500 bbls of deck drainage during a storm event. For production operations, the technology basis is commingling the captured deck drainage with produced water for treatment and disposal. For drilling operations, the captured deck

drainage is subject to a zero discharge limitation because this is the preferred option for drilling waste.

Since two options were considered for produced water disposal at production facilities, Option 2 is further divided into the following options:

Option 2a) Commingling of the first flush volume with produced water followed by treatment and disposal by zero discharge. Zero discharge is accomplished by onsite subsurface injection or offsite commercial disposal.

Option 2b) Commingling of the first flush volume with produced water followed by treatment and disposal by improved gas flotation and surface discharge.

In both cases, zero discharge would be required for the first flush for drilling operations.

Table XIII-1 presents a summary of the compliance cost estimates for the options considered. The methodology used to derive these cost estimates is presented in the following sections.

3.0 COMPLIANCE COST CALCULATIONS FOR PRODUCTION OPERATIONS - GULF OF MEXICO

The average amount of deck drainage from the facilities that reported deck drainage in the 1993 Coastal Questionnaire is used to determine costs for this waste stream. Capital and O&M costs for an average size facility are developed for each disposal category (identified by type of location and disposal method) based on this average flow. The number of facilities that fall into each disposal category are then multiplied by the average facility cost.

Compliance costs for Options 2a and 2b are based on the average volume of deck drainage reported in the 1993 Coastal Oil and Gas Questionnaire and the estimated number of production facilities.[1] Disposal costs are based on the commingling of the deck drainage with produced water for treatment and disposal. In the compliance costs analysis for produced water, the production facilities were separated into land-access and water-access facilities. The same approach was used for deck drainage because of the commingling of deck drainage with produced water. Appendix XIII-I presents the detailed compliance cost calculations for capital and O&M costs.

TABLE XIII-1

SUMMARY OF COMPLIANCE COSTS FOR DECK DRAINAGE OPTIONS FOR PRODUCTION AND DRILLING OPERATIONS IN THE GULF OF MEXICO AND COOK INLET, ALASKA

	Capital Costs			Annual O&M Costs		
Option	Production Operations	Drilling Operations	Production and Drilling Operations	Production Operations	Drilling Operations	Production and Drilling Operations
Gulf of Mexico						
Option 1 - BPT	$0	$0	$0	$0	$0	$0
Option 2a - Zero Discharge of First Flush	$50,400,119	$0	$50,400,119	$4,284,778	$1,685,615	$5,970,393
Option 2b - Discharge of First Flush Following Improved Gas Flotation	$50,400,119	$0[a]	$50,400,119[a]	$3,890,094	$1,685,615[a]	$5,575,709[a]
Cook Inlet, Alaska						
Option 1 - BPT	$0	$0	$0	$0	$0	$0
Option 2a - Zero Discharge of First Flush	b	b	$80,000	b	b	$1,147,832
Option 2b - Discharge of First Flush Following Improved Gas Flotation	b	b	$80,000	b	b	$678,609
Overall Total						
Option 2a - Zero Discharge of First Flush	-	-	$50,480,119	-	-	$7,118,225
Option 2b - Discharge of First Flush Following Improved Gas Flotation	-	-	$50,480,119[a]	-	-	$4,568,703[a]

[a]: The costs included for drilling operations in the Gulf region for this option are for zero discharge because deck drainage cannot be commingled with produced water onsite and therefore improved gas flotation is not applicable to drilling operations under this option.

[b]: On Cook Inlet platforms, deck drainage is from both production and drilling sources combined.

Tables XIII-2 and XIII-3 provide the total estimated costs for zero discharge of the first flush and surface discharge via gas flotation at the estimated 853 production facilities in the Gulf of Mexico region. All facilities that were estimated to be in service in 1992[2] are assumed to generate deck drainage, whether or not produced water is discharged. (Note: As discussed in Section XI, 216 out of 853 production facilties are estimated to be affected by produced water requirements, because all other facilities are currently not discharging produced waters. However, the 853 facilities are not required to meet zero discharge for deck drainage.) The capital costs are the same for both Options 2a and 2b because these costs are associated only with the deck drainage collection and storage equipment. No capital costs were

TABLE XIII-2

ANNUAL COST FOR GULF OF MEXICO PRODUCTION OPERATIONS DECK DRAINAGE OPTION 2B: DISCHARGE OF FIRST FLUSH BY IMPROVED GAS FLOTATION

Access Type	Disposal Type	Capital Cost Per Facility[a]	O&M Cost Per Facility[a]	Number of Facilities[b]	Total Capital Cost	Total Annual O&M Cost
Land	Flotation	$59,124	$1,121	181.9	$10,753,699	$203,892
Land	Commercial	$59,124	$18,614	67.5	$3,990,241	$1,256,247
Water	Flotation	$74,979	$224	346.8	$26,006,333	$77,694
Water	Commercial	$74,979	$18,277	128.7	$9,649,845	$2,352,262
Total				**724.9**	**$50,400,119**	**$3,890,094**

[a] See Appendix XIII-1
[b] See Table XIII-4

TABLE XIII-3

ANNUAL COST FOR GULF OF MEXICO PRODUCTION OPERATIONS DECK DRAINAGE OPTION 2B: DISCHARGE OF FIRST FLUSH BY IMPROVED GAS FLOTATION

Access Type	Disposal Type	Capital Cost Per Facility[a]	O&M Cost Per Facility[a]	Number of Facilities[b]	Total Capital Cost	Total Annual O&M Cost
Land	Flotation	$59,124	$1,121	181.9	$10,753,699	$203,892
Land	Commercial	$59,124	$18,614	67.5	$3,990,241	$1,256,247
Water	Flotation	$74,979	$224	346.8	$26,006,333	$77,694
Water	Commercial	$74,979	$18,277	128.7	$9,649,845	$2,352,262
Total				**724.9**	**$50,400,119**	**$3,890,094**

[a] See Appendix XIII-1
[b] See Table XIII-4

included for treatment and disposal because the annual deck drainage volume is only 1.5 to 1.7 percent of the average facility annual produced water volume (see Section IX.3.2.2). O&M costs for treatment and disposal were included and were based on the average O&M costs for produced water at land-access and water-access facilities. The following sections describe the assumptions, data, and methodology used to calculate these cost estimates.

3.1 Number of Facilities in Each Costing Category

As noted in Section IX.3.2.1, EPA estimates that 19.5 percent of the production operations in the Gulf of Mexico region commingle deck drainage with produced water for disposal by subsurface injection. Therefore, it is assumed that 19.5 percent of the facilities that currently inject produced water already commingle deck drainage and will not incur any cost under the zero discharge option.

This 19.5% is applied equally to both land-based and water-based facilities and applies to facilities that are projected to install an injection system for produced water to meet the produced water zero discharge option (i.e., "medium/large" facilities, as described in Section XI). Table XIII-4 shows the estimated number of facilities by disposal category and the factors used to develop these numbers.

3.2 Assumptions for Production Facilities

- The average annual volume of deck drainage in 1992 was 11,644 bbls per production facility.[3] The New Orleans area received approximately 80 inches of rainfall in 1992.[4] The equivalent surface area needed to generate 11,644 bbls of rainwater at 80 inches is 9,807 sq ft which is assumed to be the average size of a facility. This is roughly equivalent to the surface area of the Texaco tank battery at Port Neches which measured 90 ft x 100 ft (9,000 sq ft) and generated 210 bpd (76,650 bpy) of oil and 4,000 bpd (1,460,000 bpy) of produced water.[5] This volume is roughly equivalent to the estimated average oil production per facility of 237 bpd (86,483 bpy) and 245 bpd (89,492 bpy) for facilities that inject and surface discharge produced water, respectively.[3] The produced water volume is equivalent to 2.08 and 1.93 times the estimated average water production per facility for facilities that inject and surface discharge produced water, respectively. Therefore, the average volume of 11,644 bpy appears to be consistent with field observations.

TABLE XIII-4

ESTIMATED NUMBER OF COASTAL GULF OF MEXICO PRODUCTION FACILITIES BY DISPOSAL CATEGORY

Type of Facility	Proposed Deck Dr. Disposal	Current Deck Dr. Disposal	Total Facilities	Percent Land vs. Water[b]	Percent Injection vs. Commercial[c]	Percent Commingling[d]	Number of Facilities
Land	Injection	Surface	853	34.4	77	80.5	181.9
Land[a]	Injection	Commingling	853	34.4	77	19.5	44.1
Land	Commercial	Surface	853	34.4	23	100	67.5
Water	Injection	Surface	853	65.6	77	80.5	346.8
Water[a]	Injection	Commingling	853	65.6	77	19.5	84.0
Water	Commercial	Surface	853	65.6	23	100	128.7
Total							**853.0**

a Facilities that are shaded (i.e., currently to estimated commingle deck drainage with produced water) will not incur any cost
b Section IX, Table IX-9
c see Section 3.5
d see Section 3.1

- The 80.5 percent of the production facilities that do not commingle deck drainage with produced water discharge the deck drainage (Section IX.3.2.1).

- A 500 bbl storage tank will be required to store, equalize and treat area runoff. This volume will hold the equivalent of 3.5 inches of rainfall at an average size facility with an area of 9,807 sq ft. The tank diameter is 15 ft.

- Separate costs were developed for land-access and water-access facilities. The separate costs include those for platform space, injection O&M and commercial disposal.

- O&M cost for injection is $0.08/bbl for water-based facilities and $0.15/bbl for land-based facilities. This cost is the average O&M cost for medium/large facilities from the produced water cost analysis for the Gulf of Mexico (Section XI.3.7.3).

- O&M costs for gas flotation is $0.01/bbl for water-based facilities and $0.09/bbl for land-based facilities. This cost is the average O&M cost for medium/large facilities from the produced water cost analysis for the Gulf of Mexico (Section XI.3.7.3).

- The only treatment chemical used will be an oxygen scavenger at a cost of $0.01/bbl, based on an oxygen scavenger cost of $9.00/gal and a dosage rate of 1.0 gal/1,000 bbl.[6] The oxygen scavenger cost will not be added to the O&M cost for commercial disposal because this treatment is only needed when deck drainage is mixed with produced water which will occur during and after transport to the commercial facility. Therefore, the oxygen scavenger cost is assumed to be already included in the commercial disposal cost.

- Commercial disposal cost is $1.63/bbl for water-based facilities and $1.66/bbl for land-based facilities (Section XI.3.1.2).

- Two 200 gpm pumps will be needed for the average facility. One of these pumps alone is capable of pumping two inches of rainfall per hour for the average size facility (9,806 sq ft). The foot print of these two pumps is assumed to be 50 sq ft.

3.3 Estimation of the First Flush Capture Volume

Capturing the first 500 bbls of deck drainage will require the capture of the first 3.5 inches of rainfall during a storm event for an average size facility (9,806 sq. ft.) (see Section IX 3.2.2). The Regional Climate Center provided the following rainfall data:[7]

- For a 24 hour duration and a return period[a] of one year, the maximum rainfall depth ranges from 3.75 inches for northwestern Louisiana to 5.0 inches in southeastern Louisiana.

- For a 24 hour duration and a return period[1] of two years, the maximum rainfall depth ranges from 4.5 inches for Northwestern Louisiana to greater than 6.0 inches in southeastern Louisiana.

This means that a 3.5 inch rainfall depth will probably be exceeded at least once per year in southern Louisiana and at most two to three times. In Texas, which receives less rainfall than Louisiana (e.g., Galveston, Texas receives 42.9 inches annually, compared to 53.7 inches for New Orleans, Louisiana[8]), the frequency of exceeding 3.5 inches of rainfall in a 24 hour period will be even less.

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[a]A "return period" is the frequency (period between occurrences) at which a storm of a given intensity will occur.

As a result of this requirement to catch only the first 3.5 inches, there will be some deck drainage discharge during severe storm events, particularly at facilities that are greater in area than the average facility. A simplified method to estimate this volume is to assume that the depth of 3.5 inches will be exceeded only once per year and to assume that the exceedence depth is the average of the maximum 24-hour storms for the one and two year return periods from the area of the Gulf Coast with the greatest rainfall, Southeastern Louisiana. These rainfall depths are 6 inches for a one year return period and 5 inches for a two year return period.[7] Using these rainfall depths for the entire Gulf Coast should compensate for the possible volume discharged from a second or third storm to exceed 3.5 inches. This method results in the following calculated depth of rainfall discharged:

Annual Depth of Rainfall Discharged per year = ((6 in. + 5 in.)/ 2) - 3.5 in. = 2.0 inches per year

Therefore, using the conservative assumption that the average annual rainfall received in the region is the same as that for New Orleans, Louisiana (53.7 inches), the volume discharged will be 2.0 inches out of 53.7 inches or 3.7%. Therefore, since the predominant source of deck drainage is rainfall, the average volume of deck drainage captured is 11,213 bpy (11,644 x 0.963). The total volume generated by all 853 production facilities is therefore estimated to be 9,932,332 bpy and the total volume captured under Options 2a and 2b is estimated to be 9,564,689 bpy. Of this volume, EPA estimates that 80.5 percent is currently being discharged (see Section XIII.3.2). This results in an estimated volume discharged of 7,995,527 bpy. The volume not captured under Options 2a and 2b that would be subject to the BPT limitations is 295,953 bbls.

3.4 Capital Cost Estimate

Capital costs are based on the installation of a 500 bbl storage tank and two centrifugal pumps with a capacity of up to 200 gpm. The data for tank and platform costs, as well as tank dimensions were obtained from the produced water cost analysis for the Gulf of Mexico (Section XI.3.2). The cost for the centrifugal pumps was obtained from a vendor (Sunda, October 1994).[9] The only difference between facilities is that the additional platform space cost is $40/sq.ft. for land-based facilities and $75/sq.ft. for water-based facilities. Capital costs are presented in detail in Appendix XIII-1.

3.5 Determination of Onsite Injection Versus Commercial Disposal

As described in Section XI.3, for water-based facilities, the produced water cost analysis used a threshold flowrate of 108.5 bpd as the point at which, as the flowrate increases, it becomes economical

to inject onsite. In the produced water cost analysis in Section XI, Table XI-11 shows that 23% of the facilities (50 out of 216) surface discharging produced water were costed for commercial disposal. In order to be consistent with cost estimates for other wastes, the 23% value will be used in this analysis. This factor was used for both options 2a and 2b.

4.0 COMPLIANCE COST CALCULATIONS FOR DRILLING OPERATIONS - GULF OF MEXICO

The 1993 Coastal Oil and Gas Questionnaire asked questions separately for new production, exploratory, recompletion, "other" and service wells. Responses for new production and exploratory wells were grouped together in this analysis because of their similarities. Responses for sidetracks of existing wells (reported as "other" wells) were also grouped with responses for recompletion because of similarities. All of the equipment to be used for zero discharge of deck drainage at drilling operations in the Gulf Region is assumed to be rented. Therefore, no capital costs will be incurred; rental costs for the equipment (pumps and tanks/barges) are included in the O&M costs.

Table XIII-5 presents the estimated total deck drainage volumes and costs of zero discharge of the 500 bbl first flush, assuming that the current disposal practice is surface discharge for all drilling operations. A review of the land-based drilling operations that reported deck drainage in the 1993 Coastal Questionnaire found none that reported surface discharge.[2] The methods of disposal reported were commercial disposal and annular injection. For water-based drilling operations, the majority of the deck drainage reported was surface discharged.[3] Therefore, the estimated compliance costs for zero discharge of deck drainage is somewhere between the total cost for water-based operations of $759,528 and the total cost of $1,685,615 for both water- and land-based operations. The following sections describe the assumptions, data, and methodology used to calculate these cost estimates.

4.1 ESTIMATING THE VOLUME OF DECK DRAINAGE CAPTURED

Considering the small surface area and deck drainage volumes associated with water-based drilling operations, it is assumed that the first flush volume of 500 bbls will not be exceeded at any time, except under extreme circumstances, and that the volume disposed under zero discharge for Option 2a is equal to the volume generated. For land-based drilling operations, the volume of 500 bbls is expected to be exceeded on numerous occasions because land-based operations cover a much greater area and thus generate higher volumes of deck drainage. For a drilling operation with a surface area of 122,500 sq ft (see Section IX.3.2.3.5), the depth of rainfall that would generate 500 bbls of area runoff is only 0.275

TABLE XIII-5

SUMMARY OF DECK DRAINAGE VOLUMES AND COSTS FOR DRILLING OPERATIONS OPTION 2A: ZERO DISCHARGE OF 500 BBL FIRST FLUSH

Location Type	Well Type	Volume Generated[a] (bbl)	Volume Captured (bbl)	Volume Discharged[d] (bbl)	Volume Recycled[e] (bbl)	Volume Zero-Disch.[f] (bbl)	Number of Wells[g]	Disposal Cost Per Well[h]	Total Cost
Land-based	New & Expl.	7,876[a]	3,049[c]	4,827	1,975	1,074	79.8	$7,778	$620,645
Land-based	Recompletion	3,938[a]	1,524[c]	2,414	1,172	352	95.6	$3,195	$305,442
Water-based	New & Expl.	516[b]	516[b]	0	0	516	152.2	$2,657	$404,395
Water-based	Recompletion	567[b]	567[b]	0	0	567	182.4	$1,947	$355,133
Overall Total		**1,186,934**	**570,961**	**615,973**	**269,648**	**301,312**	**510**	--	**$1,685,615**

[a] Appendix XIII-2
[b] Section IX.3.2. These volumes already include reduction due to recycle.
[c] Appendix XIII-2
[d] Volume generated minus volume captured
[e] Section IX.3.2
[f] Volume captured minus volume recycled
[g] Table IX-15
[h] Appendix XIII-1

inches. Appendix XIII-2 presents daily rainfall data for New Orleans for the year of 1993.[10] The total of 52.7 inches for this year is within 2% of the average annual rainfall of 53.7 inches in New Orleans and therefore is considered representative of a typical year. As discussed in Section IX, new and exploratory wells take an average of 30 days to drill and recompletions take 15 days. Appendix XIII-2 shows the volumes of deck drainage generated, the volume captured, and the remainder that can be discharged if it meets BPT and local requirements. These volumes are based on a land-based surface area of 122,500 sq ft. The captured volumes are subject to the zero discharge requirements and will be either reused in the drilling process or disposed by transporting it to an offsite commercial disposal facility. The deck drainage can also be annularly injected, however, EPA did not include this option in this analysis.

4.2 Assumptions for Land-based Drilling Operations

The assumptions and data sources for developing the compliance costs for land-based drilling operations are presented below. The assumptions used in developing the deck drainage volumes and the calculations of the cost estimates are presented in Appendix XIII-1.

- Trucking to a commercial disposal facility will be the disposal method. The cost will be $1.75/bbl for trucking and $2.00/bbl for disposal, for a total of $3.75/bbl.[11,12]

- One 500 bbl frac tank will be rented to provide storage for the 500 bbl first flush at $75/tank per day. In addition a pump will be rented for $50/day to be used to transfer rain water to the tank.[11]

4.3 Assumptions For Water-based Drilling Operations

The assumptions and data sources for developing the compliance costs for water-based "new production well" drilling operations are presented below. The calculations of the cost estimates are presented in Appendix XIII-1.

- Deck drainage will be collected in shale barges and will be included in the disposal volumes for muds and cuttings.

- Onsite storage and barging to a commercial facility will be the disposal method. The rainwater will be stored in a compartment of a shale barge. The daily cost for storage

will be one-quarter the cost of a 1,500 bbl shale barge (i.e., one of the four compartments in the shale barge). The estimated deck drainage volume of 516 bbls and 567 bbls per well for newly drilled wells and recompletions, respectively, is assumed to be collected by two barges over the course of the drilling operation, with one replacing the other. A typical 1,500-bbl shale barge has four compartments.[13] Thus, the average per-barge deck drainage volume of 258 bbls and 284 bbls for newly drilled wells and recompletions, respectively, will fill most of the 375 bbl capacity of one compartment. The rental cost is $150.00/day and will be assumed to be incurred for 30 days. Transportation costs are assumed to be one fourth the cost of two trips which was reported to be $1,000/trip.[13] The disposal cost will be $2.00/bbl.[12]

5.0 COOK INLET

Operations in Cook Inlet occur on deep water platforms where drilling and production can occur simultaneously. Thus, deck drainage from these platforms can include drainage from both drilling and production operations, and is therefore, addressed in this section as a single combined source.

As noted in Section IX, four platforms in Cook Inlet treat and surface discharge deck drainage at the platform independently from the produced water which is piped to shore-based treatment facilities. An additional five platforms commingle deck drainage with produced water for treatment and disposal at the platform. The remaining platforms commingle deck drainage with produced fluids which is then piped to shore-based treatment facilities. Since deck drainage is commingled with produced water at all but four of the platforms, commingling is consisered to be technologically feasible to perform at all platforms provided that the equipment is sized accordingly. In the development of equipment costs for the produced water BAT options for zero discharge and improved gas flotation presented in Section XI, enough excess capacity has been included to accommodate deck drainage without additional capital costs. Since all but four of the platforms already include piping arrangements to allow commingling of deck drainage with produced fluids, no capital costs will be incurred by those facilities. For the four platforms that do not commingle deck drainage, it is assumed that the piping costs will be similar to the piping costs for the installation of gas flotation systems installed at a platform. The average piping and instrumentation costs was $19,516 for the four platforms where gas flotation was costed (see Appendix IX-17). This value was rounded up to $20,000 for this estimate.

Tables XIII-6 and XIII-7 present the capital and O&M costs for Options 2a and 2b, respectively. Annual O&M costs were estimated by dividing the produced water O&M costs for each platform or shore-based facility by the produced water flowrate to get the unit per-barrel cost. The unit per-barrel cost was then multiplied by the estimated deck drainage flowrates from Table IX-17. Tables XIII-6 and XIII-7 also show the capital cost design flowrate of the produced water equipment indicating that the equipment was designed to included the deck drainage flow volume.

6.0 POLLUTANT REMOVAL CALCULATION METHODOLOGY

The pollutant removal estimates are based on the estimated volumes of deck drainage discharged and the first flush volumes captured and commingled with produced water. For the Gulf of Mexico production operations and Cook Inlet platforms, pollutant loading and reduction calculations were performed for three separate scenarios: discharge under current BPT limitations (Option 1); zero discharge of the first flush (Option 2a) and; improved gas flotation treatment and discharge of the first flush (Option 2b). For the Gulf of Mexico drilling operations, Options 2a and 2b are the same because zero discharge is the only applicable option considered for drilling wastes. Tables XIII-8 and XIII-9 present the estimated total pollutant loadings and reductions, respectively, for Options 1, 2a and 2b for the Gulf of Mexico and Cook Inlet deck drainage sources. Deck drainage characteristics are presented in Table IX-19, and loadings and reductions are calculated from these concentrations. The detailed pollutant loading and reduction tables showing individual pollutant removals for each option and each source are presented in Appendix XIII-3.

The pollutant concentrations used in the analyses were obtained from two sources. Data from the Three Facility Study used in support of the offshore rule, which are shown in Table IX-19, were used to represent deck drainage discharged under the current BPT limitations and are considered representative of settling treatment effluent. These data were reported as ranges of maximum and minimum observed values, and thus, the pollutant loading and reduction estimates in Tables XIII-8 and XIII-9 are reported as ranges. The second source of data was the calculated effluent concentrations for improved gas flotation presented in Table VIII-6. These data were used to estimate the capability of gas flotation to remove pollutants from commingled produced water and deck drainage. In calculations for compliance with Option 2b which involved both data sources, only the pollutants that are present in both data sources were used. Thus, the pollutant loading and reduction estimates for Option 2b include fewer pollutants in the total than Option 2a.

TABLE XIII-6

COOK INLET DECK DRAINAGE CAPITAL AND O&M COSTS
OPTION 2A, ZERO DISCHARGE

Facility	Deck Drainage Flow[d]	Produced Water Flow[e]	Produced Water Capital Cost Design Flow[f]	Total Produced Water O&M Cost[g]	Produced Water Unit O&M Cost[h]	Deck Drainage O&M Cost[i]	Deck Drainage Capital Cost
	(bpd)	(bpd)	(bpd)	(1992 Dollars)	($/bbl)	(1992 Dollars)	(1992 Dollars)
Trading Bay[a]	503	126,072		$6,231,081	$0.135	$24,861	$20,000[j]
Granite Point[b]	246	300	5,000	$119,450	$1.091	$97,949	$20,000[k]
E. Foreland[c]	400	3,300	10,000	$2,256,362	$1.873	$273,498	$40,000[l]
Anna	123	1,500	5,000	$180,708	$0.330	$14,818	$0
Dillon	123	2,650	10,000	$246,048	$0.254	$11,420	$0
Bruce	81	160	1,000	$152,600	$2.613	$77,254	$0
Baker	123	30	1,000	$123,090	$11.241	$504,669	$0
Tyonek	123	170	1,000	$198,144	$3.193	$143,363	$0
Total	**1,722**	**134,182**	---	**$9,507,483**	---	**$1,147,832**	**$80,000**

[a] Trading Bay Treatment Facility receives produced water from Grayling platform.
[b] Granite Point Treatment Facility receives produced water from Granite Point platform
[c] East Foreland Treatment Facility receives produced water from SWEPI "A" and SWEPI "C" platforms
[d] From Table IX-17, flowrates converted from bpy to bpd
[e] From Table VIII-2
[f] From Appendix IX-17, for Trading Bay the capital costs were for improvements to existing equipment
[g] From Table IX-15
[h] Total Produced Water O&M costs / Produced Water Flow
[i] (Deck drainage flow) x (unit O&M cost)
[j] Capital Cost for piping at Grayling platform
[k] Capital Cost for piping at Granite Point platform
[l] Capital Cost for piping at SWEPI "A" and SWEPI "C" platforms

TABLE XIII-7

COOK INLET DECK DRAINAGE CAPITAL AND O&M COSTS
OPTION 2B, IMPROVED GAS FLOTATION

Facility	Deck Drainage Flow[d]	Produced Water Flow[e]	Produced Water Capital Cost Design Flow[f]	Total Produced Water O&M Cost[g]	Produced Water Unit O&M Cost[h]	Deck Drainage O&M Cost[i]	Deck Drainage Capital Cost
	(bpd)	(bpd)	(bpd)	(1992 Dollars)	($/bbl)	(1992 Dollars)	(1992 Dollars)
Trading Bay[a]	503	126,072		$223,762	$0.005	$893	$20,000[j]
Granite Point[b]	246	300	5000	$118,178	$1.079	$96,906	$20,000[k]
E. Foreland[c]	400	3,300	10000	$126,170	$0.105	$15,293	$40,000[l]
Anna	123	1,500	5000	$156,105	$0.285	$12,801	$0
Dillon	123	2,650	10000	$174,425	$0.180	$8,096	$0
Bruce	81	160	1000	$118,235	$2.025	$59,856	$0
Baker	123	30	1000	$118,235	$10.798	$484,764	$0
Tyonek	123	170	1000	$0	$0.000	$0	$0
Total	**1,722**	**134,182**	---	**$1,035,110**	---	**$678,609**	**$80,000**

[a] Trading Bay Treatment Facility receives produced water from Grayling platform.
[b] Granite Point Treatment Facility receives produced water from Granite Point platform
[c] East Foreland Treatment Facility receives produced water from SWEPI "A" and SWEPI "C" platforms
[d] From Table IX-17, flowrates converted from bpy to bpd
[e] From Table VIII-2
[f] From Appendix IX-17, for Trading Bay the capital costs were for improvements to existing equipment
[g] From Table IX-16
[h] Total Produced Water O&M costs / Produced Water Flow
[i] (Deck drainage flow) x (unit O&M cost)
[j] Capital Cost for piping at Grayling platform
[k] Capital Cost for piping at Granite Point platform
[l] Capital Cost for piping at SWEPI "A" and SWEPI "C" platforms

TABLE XIII-8

DECK DRAINAGE TOTAL ANNUAL POLLUTANT LOADINGS

Option	Pollutant	Gulf of Mexico Production (1,000 lbs)		Gulf of Mexico Drilling (1,000 lbs)		Gulf of Mexico Total (1,000 lbs)		Cook Inlet Total (1,000 lbs)		Total (1,000 lbs)	
Option 1 - BPT	Conv.	137.58 -	4,279.47	20.42 -	635.29	158.00 -	4,914.76	10.81 -	336.38	168.82 -	5,251.14
	P.P. Org.	1.10 -	12.61	0.16 -	1.87	1.26 -	14.48	0.09 -	0.99	1.35 -	15.47
	P.P. Metal	8.48 -	21.53	1.26 -	3.20	9.74 -	24.73	0.67 -	1.69	10.41 -	26.42
	Non-Conv.	4,656.95 -	17,864.15	691.32 -	2,651.93	5,348.27 -	20,516.08	366.05 -	1,404.18	5,714.32 -	21,920.26
	Total	**4,804.10 -**	**22,177.76**	**713.17 -**	**3,292.28**	**5,517.27**	**25,470.04**	**377.62 -**	**1,743.25**	**5,894.89 -**	**27,213.29**
Option 2a - Zero Discharge of First Flush	Conv.	5.09 -	158.40	10.60 -	329.69	15.69 -	488.09	0.00 -	0.00	15.69 -	488.09
	P.P. Org.	0.04 -	0.47	0.08 -	0.97	0.13 -	1.44	0.00 -	0.00	0.13 -	1.44
	P.P. Metal	0.31 -	0.80	0.65 -	1.66	0.97 -	2.46	0.00 -	0.00	0.97 -	2.46
	Non-Conv.	172.38 -	661.24	358.77 -	1,376.25	531.15 -	2,037.49	0.00 -	0.00	531.15 -	2,037.49
	Total	**177.82 -**	**820.91**	**370.11 -**	**1,708.57**	**547.93**	**2,529.47**	**0.00 -**	**0.00**	**547.93 -**	**2,529.47**
Option 2b - Discharge by Improved Gas Flotation of First Flush	Conv.	118.19 -	302.47	10.60 -	329.69	128.79 -	632.16	9.23 -	11.76	138.02 -	643.92
	P.P. Org.	0.29 -	1.87	0.08 -	0.97	0.37 -	2.84	0.02 -	0.12	0.39 -	2.97
	P.P. Metal	0.82 -	2.32	0.65 -	1.66	1.48 -	3.98	0.04 -	0.13	1.52 -	4.10
	Non-Conv.	18.46 -	124.29	358.77 -	1,376.25	377.23 -	1,500.54	1.45 -	8.90	378.67 -	1,509.44
	Total	**137.76 -**	**430.95**	**370.11 -**	**1,708.57**	**507.86 -**	**2,139.52**	**10.74 -**	**20.91**	**518.61 -**	**2,160.42**

TABLE XIII-9

DECK DRAINAGE TOTAL ANNUAL POLLUTANT REDUCTIONS

Option	Pollutant	Gulf of Mexico Production (1,000 lbs)		Gulf of Mexico Drilling (1,000 lbs)		Gulf of Mexico Total (1,000 lbs)		Cook Inlet Total (1,000 lbs)		Total (1,000 lbs)	
Option 1 - BPT	Conv.	0 -	0	0 -	0	0 -	0	0 -	0	0 -	0
	P.P. Org.	0 -	0	0 -	0	0 -	0	0 -	0	0 -	0
	P.P. Metal	0 -	0	0 -	0	0 -	0	0 -	0	0 -	0
	Non-Conv.	0 -	0	0 -	0	0 -	0	0 -	0	0 -	0
	Total	**0 -**	**0**	**0 -**	**0**	**0 -**	**0**	**0 -**	**0**	**0 -**	**0**
Option 2a - Zero Discharge of First Flush	Conv.	132.49 -	4,121.07	9.82 -	305.60	142.31 -	4,426.66	10.81 -	336.38	153.12 -	4,763.04
	P.P. Org.	1.06 -	12.14	0.08 -	0.90	1.13 -	13.04	0.09 -	0.99	1.22 -	14.03
	P.P. Metal	8.17 -	20.74	0.61 -	1.54	8.77 -	22.27	0.67 -	1.69	9.44 -	23.97
	Non-Conv.	4,484.57 -	17,202.91	332.55 -	1,275.68	4,817.12 -	18,478.59	366.05 -	1,404.18	5,183.18 -	19,882.77
	Total	**4,626.28 -**	**21,356.85**	**343.06 -**	**1,583.72**	**4,969.34**	**22,940.57**	**377.62 -**	**1,743.25**	**5,346.96 -**	**24,683.82**
Option 2b - Discharge by Improved Gas Flotation of First Flush	Conv.	19.39 -	3,977.00	9.82 -	305.60	29.21 -	4,282.60	1.58 -	324.62	30.80 -	4,607.22
	P.P. Org.	0.81 -	8.22	0.08 -	0.90	0.89 -	9.12	0.07 -	0.67	0.95 -	9.79
	P.P. Metal	7.64 -	19.08	0.61 -	1.54	8.24 -	20.61	0.62 -	1.56	8.87 -	22.17
	Non-Conv.	0.50 -	287.86	332.55 -	1,275.68	333.05 -	1,563.54	0.04 -	23.50	333.09 -	1,587.04
	Total	**28.33 -**	**4,292.16**	**343.06 -**	**1,583.72**	**371.39 -**	**5,875.87**	**2.31 -**	**350.35**	**373.71 -**	**6,226.22**

In calculating the pollutant loadings where a portion of the deck drainage volume exceeds the first flush volume, the appropriate concentration (e.g., improved gas flotation data for Option 2b) was applied to the first flush volume and the settling effluent (BPT level) concentration was applied to the excess volume. These two values were then summed together. Where the gas flotation (Option 2b) concentrations exceeded either the minimum or maximum settling concentrations, the settling concentrations were used to develop the loadings. This was done to eliminate the appearance of an increase in pollutant loadings as the result of improved treatment. The pollutant loadings are calculated by multiplying the volume discharged by the pollutant concentration associated with the treatment technology, times unit conversion factors.

7.0 BCT COST TEST

The options proposed for existing facilities were also evaluated using the BCT cost reasonableness test. The BCT cost test methodology is the same as that described in Section X.6.1. The pollutant parameters used in this analysis are the conventional pollutants; total suspended solids (TSS) and oil and grease. Table XIII-9 lists the total pollutant removal ranges for these conventional pollutants for each regulatory option.

Table XIII-10 presents the results of the BCT cost test. All of the deck drainage options considered for BCT regulation fail the BCT cost test except for the BCT option equal to BPT. For Options 2a and 2b, the ratio of the cost of pollutant removal to pounds of pollutants removed (the POTW Test) exceeds the POTW benchmark of $0.534 per pound pollutant removed (the 1986 benchmark of $0.46 per pound adjusted to 1992 dollars). This is true even for the scenario where the maximum concentration (taken from the ranges calculated in the previous section) is assumed for BPT effluent. Since the considered options failed the first POTW test, the Industry Cost-Effectiveness Test was not performed.

TABLE XIII-10

BCT COST TEST DATA FOR DECK DRAINAGE POTW TEST

BAT/BCT Option	Region	Capital Cost	Annualized Capital Cost (a)[14]	O&M Cost	Total Annual Cost	Pollutant Reductions (lbs/yr)		POTW Cost Ratio ($/lbs)	
Option 1	Gulf of Mexico	$0	$0	$0	$0	0 -	0	$0 -	$0
Option 2a	Gulf of Mexico	$50,400,119	$7,509,618	$5,970,393	$13,480,011	142,300 -	4,426,700	$94.73 -	$3.05
Option 2b	Gulf of Mexico	$50,400,119	$7,509,618	$3,890,094	$11,399,712	29,210 -	4,282,600	$390.27 -	$2.66
Option 1	Cook Inlet	$0	$0	$0	$0	0 -	0	$0 -	$0
Option 2a	Cook Inlet	$80,000	$11,920	$1,147,832	$1,159,752	10,814 -	336,381	$107.25 -	$3.45
Option 2b	Cook Inlet	$80,000	$11,920	$678,609	$690,529	1,583 -	324,621	$436.22 -	$2.13

(a): Based on annualization factor of 0.149 from ERG, November 1994.

8.0 REFERENCES

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SECTION XIV

OPTIONS SELECTION: RATIONALE AND TOTAL COSTS

1.0 INTRODUCTION

This section presents the options EPA has selected for control of the coastal oil and gas wastestreams. A discussion of the reasons why the options were chosen, and the total costs of this proposed rulemaking is also included in this section.

2.0 SUMMARY OF OPTIONS SELECTED AND COSTS

Under this rule, EPA is co-proposing three options for the control of drilling fluids and cuttings (including any effluent from dewatering pit closures activities) for BAT effluent limitations guidelines, and NSPS. The three options considered contain zero discharge for all areas, except two of the options contain allowable discharges for Cook Inlet. One of these options, which would allow discharges meeting a more stringent toxicity limitation if selected for the final rule, would require an additional notice for public comment since the specific toxicity limitation has not been determined at this time. The three options are: Option 1 - zero discharge of all areas except Cook Inlet where discharge limitations require toxicity of no less than 30,000 pm (SPP), no discharge of free oil and diesel oil and no more than 1 mg/l mercury and 3 mg/l cadmium in the stock barite, Option 2 - zero discharge for all areas except for Cook Inlet where discharge limitations would be the same as Option 1, except toxicity would be set to meet a limitation between 100,000 ppm (SPP) and 1 million pm (SPP), and Option 3 - zero discharge for all areas. EPA is proposing PSES and PSNS prohibiting all discharges of drilling fluids and drill cuttings. BCT for drilling fluids and cuttings is being proposed as zero discharge for the entire subcategory except for Cook Inlet, Alaska. BCT limitations for drilling fluids and cuttings for Cook Inlet would require no discharge of free oil (as determined by the static sheen test).

EPA is proposing to prohibit discharges of produced water from all coastal subcategory operations except those located in Cook Inlet, Alaska, under BAT. Proposed BAT for coastal facilities in Cook Inlet would limit the discharge of oil and grease in produced water to a daily maximum of 42 mg/l and a thirty day average of 29 mg/l. EPA is proposing to prohibit discharges of produced water from all coastal

subcategory operations under NSPS, PSNS, and PSES. BCT limits for produced waters in all coastal regions (including Cook Inlet) would be set equal to the current BPT limitations, which limit the discharge of oil and grease to a daily maximum of 72 mg/l and a thirty day average of 48 mg/l.

BCT for treatment, workover and completion fluids is proposed to be set equal to current BPT limits prohibiting discharges of free oil, with compliance to be determined by use of the static sheen test. EPA is co-proposing two options for BAT and NSPS limitations for treatment, workover and completion fluids. Option 1 would require no discharge of free oil and prohibit discharges to freshwaters of Texas and Louisiana. This option reflects current practice. Option 2 would require the same limitations as the preferred option for produced water. This option would require for BAT that discharges of treatment, workover and completion fluids would be prohibited in all coastal areas except Cook Inlet. In Cook Inlet, these discharges would be required to meet a daily maximum oil and grease limitation of 42 mg/l and a 30 day average of 29 mg/l. Option 2 would require zero discharge of these fluids everywhere for NSPS. EPA proposes zero discharge as PSES, and PSNS for treatment, workover and completion fluids.

BPT, BCT, BAT, NSPS, PSES, and PSNS are being proposed for produced sand and would prohibit all discharges of this wastestream. The only BPT effluent limitations guidelines being proposed today are for produced sand which is the only wastestream for which BPT limits have not been previously promulgated.

BCT, BAT, and NSPS limits being proposed for deck drainage would be set equal to current BPT limits prohibiting discharges of free oil, with compliance to be determined by use of the visual sheen test. EPA is proposing zero discharge for PSES and PSNS for deck drainage because collection and capture of this wastestream is technically impractical in many situations such that its direction to POTWs would rarely, if ever, occur. EPA also believes that combining this wastestream with municipal treatment facilities that may already be at full capacity should not be encouraged.

BCT is being proposed for domestic wastes as equal to BPT (which is no discharge of floating solids) with an additional requirement prohibiting the discharge of garbage. BAT is being proposed for domestic wastes to prohibit discharge of foam. NSPS is being proposed for domestic wastes as equal to BCT and no discharge of foam and no discharge of garbage. No pretreatment standards are being established for domestic wastes.

BCT and NSPS limitations for sanitary wastes are being proposed as equal to the current BPT effluent limitations guidelines. Sanitary waste effluents from facilities continuously manned by ten (10) or more persons would contain a minimum residual chlorine content of 1 mg/l, with the chlorine level maintained as close to this concentration as possible. Coastal 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. BAT is not being developed for sanitary wastes because no toxic or nonconventional pollutants of concern have been identified in this waste stream. No pretreatment standards are being established for sanitary wastes.

These options and their costs are presented in Table XIV-1. Annualized costs (for O&M and capital costs combined) are also presented here. The derivation of annualized cost is presented in a separate document prepared for this proposal entitled Economic Impact Analysis of Proposed Effluent Limitations Guidelines and Standards for the Coastal Oil & Gas Industry.[1]

The limitations proposed under each option for all wastestreams are presented, by effluent guideline level, in Table XIV-2 through XIV-7.

3.0 OPTION SELECTION RATIONALE

3.1 DRILLING FLUIDS AND CUTTINGS

3.1.1 BAT and NSPS

EPA has not selected a preferred option for control of drilling fluids and drill cuttings under BAT and NSPS but, rather is co-proposing all three options. EPA has determined, based on available information, that all three options are technologically and economically achievable and have acceptable non-water quality impacts. However, due to possible operational interferences (for Option 3), the lack of sufficient data to set a toxicity limitation more stringent than 30,000 ppm (SPP) (for Option 2) and the high cost-effectiveness results for both Options 2 and 3, a preferred option has not been selected.

A large majority of operators are already discharging at levels less toxic than the toxicity limitations of 30,000 ppm (SPP) contained in Option 1. Thus, this is a no cost option incurring no economic or non-water quality environmental impacts.

Option 2 requires zero discharge for all operators except in Cook Inlet where operators would be required to meet the Offshore subcategory limitations in addition to a toxicity limitation of between

TABLE XIV-1
Costs of Preferred BAT Options (1992$)

Wastestream	Selected Options	Costs					
		BAT			NSPS		
		Capital ($MM)	O&M ($MM/yr)	Annualized[a] ($MM/yr)	Capital ($MM)	O&M ($MM/yr	Annualized[a] ($MM/yr)
Drilling Fluids and Cuttings	Co-Proposal Option 1: Zero Discharge except Cook Inlet (30,000 ppm toxicity)	NA[b]	NA[b]	0	NA[b]	NA[b]	0[b]
	Option 2: Zero Discharge except Cook Inlet (100,000 - 1 million ppm toxicity)	NA[b]	NA[b]	1.37[b]	NA[b]	NA[b]	0[b]
	Option 3: Zero Discharge	NA[b]	NA[b]	3.89[b]	NA[b]	NA[b]	0[b]
Produced Water	BAT: Option 4: Zero discharge: Cook Inlet Improved Gas Flotation	88.54	17.66	30.86	NA	NA	NA
	NSPS: Option 5: Zero Discharge All	NA	NA	NA	1.73	0.39	4.48
Treatment, Workover, and Completion Fluids	Co-proposal Option 1: BPT	NA[c]	0	0	0	0	0
	Option 2a: Zero Discharge	NA[c]	0.61	0.61	NA[c]	0.079	0.079
	Option 2b: Gas Flotation	NA[d]	NA[d]	NA[d]	NA[d]	NA[d]	NA[d]
Total	--	--	--	**30.86 - 35.36**	--	--	**4.48 - 5.00**
				Grand Total: (BAT and NSPS combined)		**$35.34 - $40.36**	

[a] Annualized ($ million/yr) Costs from the Economic Impact Analyses (ERG, Nov. 1994)
[b] The total compliance costs for drilling fluids and cuttings were not segregated into capital and O&M costs (see Section X of this document).
[c] Capital costs were not calculated for treatment, workover, and completion fluids (see Section XII of this document).
[d] Not considered as an option because this is not the preferred option selected for produced water.

NA Not Applicable

TABLE XIV-2
Proposed BPT Effluent Limitations

Pollutant Parameter Waste Source	Maximum for any 1 day	Average of Values for 30 consecutive days shall not exceed	Residual chlorine minimum for any 1 day
Produced Sand	zero discharge	zero discharge	NA

TABLE XIV-3
BAT Effluent Limitations

Stream	Pollutant Parameter	BAT Effluent Limitations
Produced Water		
A) All coastal areas except Cook Inlet		No discharge
B) Cook Inlet	Oil & Grease	The maximum for any one day shall not exceed 42 mg/l, and the 30-day average shall not exceed 29 mg/l
Drilling Fluids and Drill Cuttings		
Option 1		
A) All coastal areas except Cook Inlet		No discharge
B) Cook Inlet	Free Oil[1]	No discharge
	Diesel Oil	No discharge
	Mercury	1 mg/kg dry weight maximum in the stock barite
	Cadmium	3 mg/kg dry weight maximum in the stock barite
	Toxicity	Minimum 96-hour LC50 of the SPP shall be 3 percent by volume[3]
Option 2		
A) All coastal areas except Cook Inlet		No discharge
B) Cook Inlet	Free Oil[1]	No discharge
	Diesel Oil	No discharge
	Mercury	1 mg/kg dry weight maximum in the stock barite
	Cadmium	3 mg/kg dry weight maximum in the stock barite
	Toxicity	Minimum 96-hour LC50 of the SPP shall be 10 percent to 100 percent by volume[3]
Option 3		
All coastal areas		No discharge
Well Treatment, Workover and Completion Fluids		
Option 1		
A) All coastal areas except freshwater of Texas and Louisiana	Free Oil[1]	No discharge
B) Freshwaters of Texas and Louisiana		No discharge
Option 2		
A) All coastal areas except Cook Inlet		No discharge
B) Cook Inlet	Oil and Grease	The maximum for any one day shall not exceed 42 mg/l, and the 30-day average shall not exceed 29 mg/l
Produced Sand		No discharge
Deck Drainage	Free Oil[2]	No discharge
Domestic Waste	Foam	No discharge

(1) As determined by the static sheen test.
(2) As determined by the presence of a film or sheen upon or a discoloration of the surface of the receiving water (visual sheen).
(3) As determined by the toxicity test (see Appendix 2 of 58 FR 12454, March 4, 1993).

TABLE XIV-4
Proposed BCT Effluent Limitations

Stream	Pollutant Parameter	BCT Effluent Limitations
Produced Water (all facilities)	Oil & Grease	The maximum for any one day shall not exceed 72 mg/l, and the 30-day average shall not exceed 48 mg/l
Drilling Fluids and Drill Cuttings		
A) All facilities except Cook Inlet		No discharge
B) Cook Inlet	Free Oil	No discharge (1)
Well Treatment, Workover, and Completion Fluids	Free Oil	No discharge (1)
Produced Sand		No discharge
Deck Drainage	Free Oil	No discharge (2)
Sanitary Waste		
Sanitary M10	Residual Chlorine	Minimum of 1 mg/l maintained as close to this concentration as possible
Sanitary M91M	Floating Solids	No discharge
Domestic Waste	Floating Solids and garbage	No discharge of Floating Solids or garbage (3)

(1) As determined by static test 40 CFR Part 435, Subpart A, Appendix 1
(2) As determined by the presence of a film or sheen upon or a discoloration of the surface of the receiving water (visual sheen).
(3) As defined in 40 CFR § 435.41(1).

TABLE XIV-5
NSPS Effluent Limitations

Stream	Pollutant Parameter	NSPS/PSNS Effluent Limitations
Produced Water (all facilities)		No discharge
Drilling Fluids and Drill Cuttings		
Option 1		
A) All coastal areas except Cook Inlet		No discharge
B) Cook Inlet	Free Oil[1]	No discharge
	Diesel Oil	No discharge
	Mercury	1 mg/kg dry weight maximum in the stock barite
	Cadmium	3 mg/kg dry weight maximum in the stock barite
	Toxicity	Minimum 96-hour LC50 of the SPP shall be 3 percent by volume [3]
Option 2		
A) All coastal areas except Cook Inlet		No discharge
B) Cook Inlet	Free Oil[1]	No discharge
	Diesel Oil	No discharge
	Mercury	1 mg/kg dry weight maximum in the stock barite
	Cadmium	3 mg/kg dry weight maximum in the stock barite
	Toxicity	Minimum 96-hour LC50 of the SPP shall be 10 percent to 100 percent to 100 percent by volume [3]
Option 3		
All coastal areas		No discharge
Well Treatment, Workover and Completion Fluids		
Option 1		
A) All coastal areas except freshwater of Texas and Louisiana	Free Oil[1]	No discharge
B) Freshwaters of Texas and Louisiana		No discharge
Option 2		
A) All coastal areas except Cook Inlet		No discharge
B) Cook Inlet	Oil and Grease	The maximum for any one day shall not exceed 42 mg/l, and the 30-day average shall not exceed 29 mg/l
Produced Sand		No discharge
Deck Drainage	Free Oil[2]	No discharge
Sanitary Waste		
Sanitary M10	Residual Chlorine	Minimum of 1 mg/l and maintained as close to this concentration as possible
Sanitary M91M	Floating Solids	No discharge
Domestic Waste	Floating Solids, Garbage(4) and Foam	No discharge of floating solids or garbage or foam

(1) As determined by the static sheen test
(2) As determined by the presence of a film or sheen upon or a discoloration of the surface of the receiving water (visual sheen).
(3) As determined by the toxicity test (see Appendix 2 of 58 FR 12454, March 4, 1993).
(4) As defined in 40 CFR § 435.41(1)

TABLE XIV-6
Proposed PSES Effluent Limitations

Stream	Pollutant Parameter	PSES Effluent Limitations
Produced Water		No discharge
Drilling Fluids and Drill Cuttings		No discharge
Well Treatment, Workover, and Completion Fluids		No discharge
Produced Sand		No discharge
Deck Drainage		No discharge

TABLE XIV-7
Proposed PSNS Effluent Limitations

Stream	Pollutant Parameter	PSNS Effluent Limitations
Produced Water (all facilities)		No discharge
Drilling Fluids and Drill Cuttings		No discharge
Well Treatment, Workover, and Completion Fluids		No discharge
Produced Sand		No discharge
Deck Drainage		No discharge

100,000 ppm (SPP) and 1,000,000 ppm (SPP). This option would cost $1.4 million annually and results in less than a 0.1 percent reduction in estimated lifetime production for Cook Inlet platforms which would not significantly reduce the profit potential for these operators.[2] Option 2 would result in the removal of approximately 3.9 million pounds of pollutants being discharged per year (or 1264 pounds in toxic equivalents)[2], assuming a volume of 17 percent of the discharges would not meet a toxicity limit of between 100,000 ppm and one million ppm (SPP) and would therefore be disposed of by grinding and injection or on land. Out of the 3.9 million pounds removed annually less than 0.02 percent consists of toxic priority pollutants (or 642 pounds).[2]

Due to limitations with the data base, EPA is currently only able to estimate an achievable toxicity limit in the range of 100,000 ppm (SPP) to one million ppm (SPP). EPA will continue to

evaluate toxicity test results and volumes and other data for drilling fluids used and discharged in Cook Inlet in an effort to derive a more specific limitation. A supplemental notice presenting the data and soliciting comment may be necessary prior to promulgation.

Option 3 would cost the industry $3.9 annually and result in the reduction of 23 million pounds of pollutants being discharged per year (or 7375 in toxic pounds equivalents).[2] Zero discharge of drilling fluids and drill cuttings is widely practiced in other coastal areas other than Cook Inlet, including the Gulf of Mexico, California, and the North Slope of Alaska. In Cook Inlet, zero discharge is not currently practiced but for a small amount of drilling fluids (approximately one percent) that do not meet permit limits. Zero discharge is technologically available because operators are able to comply with zero discharge by either disposing of their drilling fluids and drill cuttings onshore or by grinding and injecting the waste. The costs of this option would result in a 2.7 percent reduction in the estimated lifetime production for Cook Inlet platforms, which would not significantly reduce the profit potential for these operators.[1] Thus, EPA believes these costs are economically achievable. However, concerns have been raised that zero discharge would interfere with drilling operations, in part because the weather conditions and tidal fluctuations in the Inlet pose logistical difficulties for drilling waste transportation especially during winter months. In addition, while Option 3 would result in the removal of 23 million pounds of pollutants per year, less than 0.02 percent of which are toxic pollutants[2], the $3.9 million annually incurred by industry to remove the 3760 pounds of priority toxic pollutants indicates that this option is not cost effective. In Cook Inlet, operators are not currently practicing zero discharge. EPA estimates that to comply with a total zero discharge requirement, 24 percent of the drilling fluids and drill cuttings would be ground and injected into dedicated wells, and 76 percent would be disposed of onshore.

EPA does not expect any new source development wells drilled in Cook Inlet in the seven years following the scheduled promulgation of this rule. This is because all development wells are expected to be drilled from existing platforms in Cook Inlet. According to the definition of new sources, these wells would be existing sources. Additionally, any drillings that may occur in the recently discovered Sunfish formation in Upper Cook Inlet, are projected to be exploratory wells, which are also existing sources according to the new source definition. Thus, no costs will be attributed to NSPS in Cook Inlet because no new sources are projected for this area. However, in the case that a new source would be drilled in Cook Inlet, EPA has determined that zero discharge would not pose a barrier to entry for the drilling project.[1] The same options are being considered for NSPS as for BAT, no one preferred NSPS option is being selected for this proposal. Since the NSPS requirements would be the same as those for BAT, costs to meet zero discharge would be equal to or less than BAT. Costs may be less than BAT

because process modifications can be incorporated into the drilling rig design prior to its installation rather than retrofitting an existing operation. Since EPA has determined that BAT is economically achievable, equivalent NSPS requirements would also be economically achievable, and cause no barrier to entry.

EPA also finds the non-water quality environmental impacts of zero discharge to be acceptable (see Section XVI of this document). Again, non-water quality environmental impacts attributable to this rule would occur only in Cook Inlet. The air emissions and energy requirements associated with waste transportation were calculated for the two operators expected to utilize onshore landfill disposal to accommodate the wastes from their drilling operations. For the remaining two operators who will be drilling and do not have access to onshore disposal, EPA has calculated the air emissions and energy requirements resulting from grinding and injection to meet zero discharge. EPA has found that these non-water quality environmental impacts represent only a very small fraction of the total air emissions and energy requirements from normal operations, and that these non-water quality environmental impacts are acceptable. As stated above, EPA does not expect any new sources to be initiated in Cook Inlet. EPA, however, believes that the non-water quality environmental impacts resulting from any such activity would be equal to or less than those anticipated for existing sources, which EPA has found acceptable.

3.1.2 BCT

As discussed in Section VII of this document, Option 2 (prohibition of the discharge of free oil and diesel oil, limitations on cadmium and mercury in the stock barite, and toxicity limitations of between 100,000 and 1 million ppm (SPP)) and Option 3 (zero discharge all) did not pass the BCT cost test. Thus, BCT is being proposed as equal to Option 1 which is zero discharge everywhere except for Cook Inlet where BPT would apply.

In addition to considering setting the BCT limitations equal to BPT, EPA considered two additional BCT options for control of conventional pollutants in drilling fluids and drill cuttings. Both of these options would require zero discharge of drilling fluids and drill cuttings throughout the subcategory except in Cook Inlet. Because all operators throughout the entire subcategory, except in Cook Inlet, are currently meeting a zero discharge requirement, or in the case of dewatering effluent, are practicing zero discharge already, there is zero cost and zero removal of conventional pollutants for the limitation. Thus, EPA has determined that zero discharge passes the BCT cost tests and other statutory factors and proposes a BCT limitation equal to zero discharge for all areas except Cook Inlet.

In Cook Inlet, EPA considered either zero discharge (Option 3) or allowing discharge based on requirements identified in Option 2. EPA did not consider Option 1 for Cook Inlet, allowing discharge at the current Offshore Guidelines limitations with a toxicity limit of 30,000 ppm (SPP), as a distinct BCT option because the amount of removal of the conventional pollutant oil and grease, as oil, from discharge by this level of toxicity could not be determined from that removed by the current BPT requirement of no free oil. Both candidate BCT options fail the BCT cost test, and BCT is set equal to Option 1 for this proposal which is equal to zero discharge everywhere except for Cook Inlet where BPT would apply.

3.1.3 Pretreatment Standards

Based on the 1993 Coastal Oil and Gas Questionnaire and other information reviewed as part of this rulemaking, EPA has not identified any existing coastal oil and gas facilities which discharge drilling fluids and cuttings to publicly owned treatment works (POTWs), nor are any new facilities projected to direct these wastes in such manner. However, due to the high solids content of drilling fluids and cuttings, EPA is proposing to establish pretreatment standards for existing and new sources equal to zero discharge because these wastes are incompatible with POTW operations (see Section XV). For PSNS, zero discharge would not cause a barrier to entry.[1]

3.2 Produced Water

3.2.1 BAT and NSPS

As BAT for produced water, EPA proposes zero discharge everywhere except facilities in Cook Inlet would be required to meet limitations based on improved gas flotation (Option 4). This option prohibits discharges of produced water from all coastal facilities, except for those facilities located in Cook Inlet. Coastal facilities in Cook Inlet would be required to comply with the oil and grease limitations (29 mg/l 30-average, 42 mg/l daily maximum) based on improved operating performance of gas flotation. This option will remove 4.3 billion pounds per year of pollutants. EPA has determined this option to be economically achievable and technologically available, and that it reflects the BAT level of control.

Zero discharge is technologically available because injection of produced water is currently ongoing in much of the coastal subcategory at the present time, and adequate geological formations exist to accept produced water. By 1996 (the projected date of promulgation of this rule), 75 percent of the facilities in the Gulf region will already be meeting zero discharge. Option 4 is economically achievable

for those operators (the remaining 25%) that would otherwise be discharging in 1996, as the economic analysis shows.[1] The oil and grease limit applicable to Cook Inlet is technologically available.

Option 4 is economically achievable because, as the economic analysis shows, total production losses in terms of oil production as a result of this proposed rule are expected to range between 1.0 percent and 1.7 percent of total lifetime production for both Cook Inlet and the Gulf.[1] Additionally, only 2.4 percent of all current Gulf coastal wells (111 out of 4675 current Gulf coastal wells) and no Cook Inlet platforms are considered likely to shut in as a result of this rule. These shut-in wells tend to be relatively low - producing and marginal wells. At most, only 2.8 percent of the operators in the Gulf (12 of the estimated 435 Gulf coastal operators) might fail as a result of a zero discharge requirement and no firm failure is expected in Cook Inlet, as a result of meeting oil and grease limits of 29 mg/l 30-day average and 42 mg/l daily maximum for produced water. (The range of firm failures in the Gulf is actually 0-12, but because data were not available to rule out the possibly of failures, EPA assumed possible failures to be actual failures.) The "average" Gulf coastal firm does not discharge produced water and coastal firms are expected to face average (medium) declines in equity or working capital of 0 percent. Of the 122 discharging firms, average (medium) declines in equity or working capital of 0.37 percent and 2.63 percent, respectively, are expected to occur. These impacts, combined with the fact that most Gulf coastal operators (72 percent) will not be discharging by 1996, show Option 4 to be economically achievable.

Option 5, zero discharge all, was not selected based on the unacceptable economic impacts estimated for the Cook Inlet operators.[1] EPA's economic analysis shows that 3 of 13 platforms would be shut-in as a result.[1] EPA did not select the "Flotation All" or "BPT All" options as preferred because they, applied industry-wide, do not represent BAT or NSPS level of control. As stated previously, all coastal operations in California, Alabama, Florida, some parts of Louisiana, and the North Slope of Alaska do not discharge produced water, but inject their produced water underground either to comply with permit limitations or to enhance hydrocarbon recovery. EPA has therefore concluded that control options based on the continued discharge of produced water in all areas of the country do not represent BAT or NSPS.

Non-water quality environmental impacts for the proposed Option 4 consist of incremental air emissions of approximately 2,800 tons/year across the entire subcategory. Given that an average Gulf coast production facility may alone produce approximately 188 tons/year of emissions, this option would increase air emissions by about 13 percent. EPA considers this increase to be acceptable.

For NSPS control of produced water discharges from new sources, EPA is proposing the "Zero Discharge All" (Option 5) prohibiting discharges of produced water from all new sources. Option 5 is economically achievable for the reasons discussed in the economic impact analysis.[1] This NSPS option is estimated to cost approximately $4.5 million annually for the entire coastal subcategory. This cost would be incurred only by Gulf Coast operators where EPA estimates that approximately 6 new production facilities will be constructed per year. No new sources are expected in the Cook Inlet. However, were new sources to be installed in Cook Inlet, the preferred NSPS option of zero discharge is not expected to cause a barrier to entry because new project operations would still be quite profitable.[1] In addition, EPA has determined the non-water quality environmental impacts to be acceptable for the NSPS option for produced water. Total incremental emissions from the proposed option is approximately 64 tons/year for NSPS. As a comparison, an average Gulf coast production facility may produce approximately 188 tons/year of emissions. EPA considers this increase in non-water quality impacts to be acceptable.

3.2.2 BCT

As discussed earlier in Section VIII of this document, all options except Option 1: "BPT All" fail the BCT cost tests, and thus, EPA proposes to establish BCT limitations equal to BPT. Costs for the "BPT All" option are equal to zero because facilities are complying with the current BPT limitations.

3.2.3 Pretreatment Standards

Based on the 1993 Coastal Survey and other information reviewed as part of this rulemaking, EPA has not identified any existing coastal oil and gas facilities which discharge produced water to publicly owned treatment works (POTWs), nor are any new facilities projected to direct their produced water discharge in such manner. However, because EPA is proposing a limitation requiring zero discharge for those existing facilities, there is the potential that some facilities may consider discharging to POTWs in order to meet the BAT and/or NSPS limitations. Pretreatment standards for produced water are appropriate because EPA has identified the presence of a number of toxic and nonconventional pollutants, many of which are incompatible with the biological removal processes at POTWs (see Section XV). Large concentrations of dissolved solids in the form of various salts in the produced water cause the discharge to POTWs to be incompatible with the biological treatment processes because these "brines" can be lethal to the organisms present in the POTW biological treatment systems.

EPA is proposing to require pretreatment standards for existing and new sources (PSES and PSNS, respectively) that would prohibit the discharge of produced water. The technology basis for compliance with PSES and PSNS would be the same as that for BAT and NSPS zero discharge limits. The cost projection for both PSES and PSNS are considered to be zero since no existing sources discharge to POTWs, and there are no known plans for sources to be installed in locations amenable to sewer hookup. Also, because no facilities are discharging to POTWs, EPA proposes that PSES and PSNS requiring zero discharge be effective as of the effective date of this rule. Because zero discharge for new sources is economically achievable, the costs of complying with zero discharge would not be a barrier to entry. Non-water quality environmental impacts would be similar to those for new sources, which EPA has found to be acceptable. Thus, EPA has determined that pretreatment standards for new sources that are equal to NSPS are economically achievable and technologically available for PSNS, and that the non-water quality environmental impacts are acceptable.

3.3 Treatment, Workover, and Completion Fluids

EPA is proposing to establish BCT limitations equal to BPT, prohibiting the discharge of free oil in well treatment, workover, and completion fluids. Compliance with this limitation would be determined by the static sheen test. Based on the available data regarding the levels of conventional pollutants present in these wastes, EPA did not identify any other options which would pass the BCT cost test other than establishing BCT equal to the existing BPT limits (see Section XII). There are no costs or non-water quality environmental impacts associated with this proposed BCT limitation and, since it is equal to BPT, it is technologically available and economically achievable.

EPA is co-proposing Option 1 and Option 2a for well treatment, workover, and completion fluids for BAT and NSPS. (Option 2b is not proposed because discharges based on improved gas flotation technology was not an option selected for produced water.) EPA has determined that both options are technologically and economically achievable[1] and have acceptable non-water quality impacts (see Section XVI of this document). However, due to the high cost effectiveness results for Option 2a[2] (requiring the same limitations as proposed for produced water), a preferred option has not been selected. Option 1, which would prohibit the discharge of free oil and prohibit the discharge of treatment, workover and completion of fluids to freshwaters of Texas and Louisiana, reflects current regulatory requirements and thus will incur no additional compliance costs, economic or non-water quality environmental impacts. This option would result in no incremental removal of pollutants from this wastestream beyond the existing BPT requirements.

Option 2a would require for BAT zero discharge of treatment, completion, and workover fluids except for Cook Inlet, where EPA would establish oil and grease limitations of 29 mg/l 30-day average, 42 mg/l daily maximum. For NSPS, this option would require zero discharge of all treatment, completion, and workover fluids from all new sources.

Zero discharge is being achieved by many operators (except those in Texas, saline waters of Louisiana, and Cook Inlet) for the treatment, workover, and completion fluids wastestream. The technology basis for zero discharge is commingling this wastestream with produced water or sending it separately to off-site commercial disposal facilities. For Cook Inlet, this option, which also contains allowable discharge limitations is based on commingling with produced water, because commingling of these wastestreams is currently occurring in this area. The specific oil and grease limits proposed are technologically available for the same reasons they are available for control of produced water, as discussed above.

The zero discharge limitation would eliminate all discharges of toxic, conventional, and nonconventional pollutants. The oil and grease limits would be technologically based on improved gas flotation performance and serve to limit the discharge of toxic and conventional pollutants to surface waters.

Zero discharge for treatment, workover and completion fluids in Cook Inlet was not selected for this BAT option because these fluids are commingled with produced water as an integral part of their operations, and because zero discharge for produced water was determined to be uneconomical for Cook Inlet operators.

The costs to meet Option 2a for BAT ($610,000) are relatively minimal since this amount is negligible in comparison to total annual production revenue from Gulf coastal operations.[1]

Costs to achieve zero discharge everywhere for Option 2a NSPS are expected to be negligible. Out of the 187 new wells that will be drilled in the Gulf Coast, 76 percent will not discharge these fluids in freshwaters because of water quality standards requirements. The remaining 45 facilities will each generate approximately 800 bbls of treatment, workover and completion fluids per year (estimates of volumes from the 1993 Coastal Oil and Gas Questionnaire). While some of these fluids may be directed for treatment and disposal to existing production facilities, EPA is conservatively estimating costs of the Option 2a NSPS assuming all of these fluids would be directed to new production facilities for treatment

and disposal (or be treated on-site at the new source). For the Gulf, the NSPS requirements under this Option 2a would be the same as those for BAT, thus costs would either be equal to BAT, or less than BAT since new sources can more efficiently design their facilities to comply with zero discharge. Costs for new sources in the Gulf generating treatment, workover and completion fluids to meet zero discharge would be approximately $520,000 per year which is negligible in relation to annual production revenue from Gulf coastal operators.[1]

For Cook Inlet, costs to meet Option 2a requirements for treatment, workover and completion fluids are included in the cost analysis for produced water because current practice there is commingling of these wastestreams. While EPA does not anticipate any new sources to be constructed in Cook Inlet, and therefore has not attributed any costs to NSPS, the NSPS would not cause a significant barrier to entry.[1] These impacts are only a small incremental increase over the impacts resulting from the controls on produced water and drilling fluids and cuttings. Finally the non-water quality environmental impacts of this Option 2a are believed to be acceptable, because like their volumes, they are relatively small (see Section XVI of this document) as discussed below.

Option 2a would result in the removal of 3.9 million pounds of conventional, toxic and non-conventional pollutants annually (a total of 2140 in toxic pound equivalents[2]). However the amount of toxic priority pollutants removed is approximately 0.02 percent of this total. The annual compliance costs of $1.1 million (for BAT and NSPS combined) to remove 800 pounds of priority toxic pollutants indicates that this option is not cost effective.[2]

For BCT, EPA is proposing to establish limitations equal to BPT, prohibiting the discharge of free oil and TWC fluids. No other options passed the BCT cost tests. No costs are attributed to this BCT option because it reflects current practice.

Pretreatment standards for treatment, workover, and completion fluids are being proposed equal to zero discharge. This is because their chemical composition, like produced water, tends to be high in total dissolved which may interfere with POTW operations (see Section XV). EPA solicits comments on these issues. Zero discharge for NSPS would not pose barrier to entry for the same reason as discussed under NSPS for this wastestream.[1]

3.4 DECK DRAINAGE

EPA has selected BPT as its preferred option for BAT and NSPS for deck drainage. Since free oil discharges are already prohibited under BPT, there are no incremental compliance costs, pollutant removals, or non-water quality environmental impacts associated with this control option. Since this preferred option limits free oil equal to existing BPT standards, it is technologically available and economically achievable.

EPA has rejected the first flush option for control of deck drainage for several reasons primarily relating to whether this option is technically available to operators throughout the coastal subcategory. Deck drainage is currently captured by drains and flows via gravity to separation tanks below the deck floor. However, the problems associated with capture and treatment beyond gravity feed, power independent systems, are compounded by the possibilities of back-to-back storms which may cause first flush overflows from an already full 500 bbl tank. In addition, tanks the size of 500 barrels are too large to be placed under deck floors. Installation of a 500 bbl tank would require construction of additional platform space and the installation of large pumps capable of pumping sudden and sometimes large flows from a drainage collection system up into the tank. The additional deck space would add significantly, especially for water-based facilities, to the cost of this option. Further, many coastal facilities are unmanned and have no power source available to them. Deck drainage can be channelled and treated without power under the BPT limitations.

Capturing deck drainage at drilling operations poses additional technical difficulties. Drilling operations on land may involve an area of approximately 350 square feet. A ring levee is typically excavated around the entire perimeter of a drilling operation to contain contaminated runoff. This ring levee may have a volume of 6,000 bbls, sufficient to contain 500 bbls of the first flush. However, collection of these 500 bbls when 6,000 bbls may be present in the ring levee would not efficiently capture the first flush. Costs to install a separate collection system, including pumps and tanks, would add significantly to the cost of this option.

While costs are significant, the technological difficulties involved with adequately capturing deck drainage at coastal facilities is the principal reason why this option was not selected. EPA has selected the option requiring no discharge of free oil for BAT and NSPS control of deck drainage. EPA has determined that these limitations and standards properly reflect BAT and NSPS levels of control. EPA did not identify any other available technology for this waste-stream.

EPA's proposed option does not include best management practices (BMPs) for this wastestream as part of these guidelines. EPA currently believes that current industry practices, in conjunction with the requirements as proposed in the proposed general stormwater rule (58 FR 61262-61268, November 19, 1993), would be sufficient to minimize the introduction of contaminants to this wastestream to the extent possible. These stormwater requirements, if promulgated as proposed, would require an oil and gas operator to develop and implement a site-specific storm water pollution prevention plan consisting of a set of BMPs depending on specific sources of pollutants at each site. As noted in the stormwater proposal, the two types of BMPs most effective in reducing storm-water contamination are to minimize exposure (e.g., covering, curbing, or diking) and treatment type BMPs which are used to reduce or remove pollutants in storm-water discharges (e.g., oil/water separators, sediment basins, or detention ponds). BMPs that may be incorporated into system operations are discussed in Section XVI of this document.

The first flush option did not pass the BCT cost test, thus EPA is proposing that BCT limitations for deck drainage equal BPT which prohibits the discharge of free oil. No costs are attributed to this option because it reflects current practice.

EPA is proposing to limit PSES and PSNS for deck drainage as zero discharge. EPA believes that zero discharge for PSES and PSNS is preferable to establishing a limit equal to BPT because generally slugs of deck drainage would interfere with biological treatment processes at POTWs (see Section XV). Moreover, technical difficulties associated with capture of deck drainage that make it difficult to require limitations other than the BPT, no free oil limit makes it unlikely that this wastestream would be sent to POTWs.

3.5 Produced Sand

EPA is proposing to set the BPT, BCT, BAT, and NSPS limitations equal to zero discharge for produced sand. Produced sand is the only wastestream for which BPT is being proposed (BPT has been previously promulgated for all other wastestreams). As discussed in Section IX.2, produced sand is not currently being discharged into the coastal regions of Alaska, California, nor the Gulf of Mexico. EPA has determined that zero discharge reflects the BPT, BCT, BAT, and NSPS levels of control because, since it is widely practiced throughout the industry, it is both economically achievable and technologically available. The zero discharge requirement would eliminate the discharge of all pollutants present in produced sand. Because zero discharge of produced sand is already so widespread, this requirement will

result in a minimal increased cost to the industry, and non-water quality environmental impacts will be negligible. Since proposed BCT would be set equal to proposed BPT, there is no cost of BCT incremental to BPT. Therefore this option passes the BCT cost reasonableness test.

EPA is also proposing to set PSES and PSNS equal to zero discharge for produced sand. The technology basis for compliance with PSES and PSNS is the same as that for BAT and NSPS. Pretreatment standards for produced sands are being proposed as equal to zero discharge because, like drilling fluids and cuttings, their high solids content would interfere with POTW operations (see Section XV). Because EPA is not aware of any discharges of produced sands to POTWs, this requirement is not expected to incur any costs. There are no additional non-water quality environmental impacts associated with this requirement because it reflects current practice.

3.6 Domestic Wastes

The BPT limitations for domestic wastes are no discharge of floating solids. EPA is proposing to limit floating solids for BCT and NSPS. In addition, EPA is proposing to prohibit discharges of foam for BAT and NSPS. EPA is also proposing to incorporate requirements limiting discharges of garbage as defined in the U.S. Coast Guard regulations at 33 CFR Part 151.

The current Region X General Permit regulations applicable to coastal facilities in Alaska have limitations of "no free oil," "no floating solids," and "no foam." The EPA Region VI General Permits for both drilling and production operations include a prohibition on the discharge of floating solids and on the discharge of garbage as defined by Coast Guard regulations at 33 CFR Part 151 (the definition of "garbage" is included in 33 CFR 151.05). Floating solids is a conventional pollutant, while foam is a nonconventional pollutant.

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 State or 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 screen with openings no greater than 25 millimeters (approximately one inch) in diameter. Because vessels and fixed and floating platforms

must comply with these limits, EPA believes that all coastal facilities are able to comply with this limit as well.

Since these BCT, BAT, and NSPS limitations for domestic waste are already in either existing State or NPDES permits or existing 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.

Pretreatment standards are not being developed for domestic waste because they are compatible with POTWs (see Section XV).

3.7 SANITARY WASTES

Existing BPT limitations for facilities continuously manned by 10 or more people require sanitary effluent to maintain a minimum residual chlorine content of 1 mg/l, with the chlorine concentration to remain as close to this level as possible. Facilities intermittently manned or continuously manned by fewer than 10 people must comply with a BPT prohibition on the discharge of floating solids. EPA is proposing to limit sanitary wastes discharges for BCT and NSPS equal to BPT limitations.

EPA considered zero discharge of sanitary wastes based on off-site disposal to municipal treatment facilities or injection along with other oil and gas wastes. Off-site disposal would require pump out operations, that while available to certain land facilities, are not available to remote or water-based operations. Because sanitary wastes are not wastes exclusively associated with oil and gas operations, which are routinely injected into Class II wells, zero discharge was not considered for sanitary wastes. Thus, zero discharge was not considered for sanitary wastes.

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

EPA is not establishing BAT effluent limitations for the sanitary waste-stream because no toxic or nonconventional pollutants of concern have been identified in these wastes. Pretreatment standards are not being developed for sanitary wastes because they are compatible with POTWs (see Section XV).

4.0 REFERENCES

1. Eastern Research Group, Inc. (ERG), "Economic Impact Analysis of Proposed Effluent Limitations Guidelines and Standards for the Coastal Oil and Gas Industry," EPA Contract No. 68-03-0302, January 31, 1995.

2. Eastern Research Group, Inc. (ERG), "Cost Effectiveness Analysis of Proposed Effluent Limitations Guidelines and Standards for the Coastal Oil and Gas Industry," EPA Contract No. 68-C3-0302, January 31, 1995.

SECTION XV

PRETREATMENT STANDARDS

1.0 INTRODUCTION

EPA must develop pretreatment standards for existing sources (PSES) under Section 307 (b) of the Clean Water Act (CWA). Pretreatment standards are designed to prevent the discharge of the pollutants that pass through, interfere with, or are otherwise incompatible with the operation of publicly owned treatment works (POTWs). The Clean Water Act requires that pretreatment standards for existing sources are to be technology-based and analogous to the best available technology economically achievable (BAT) for direct dischargers.

Section 307 (c) of the CWA requires EPA to promulgate pretreatment standards for new sources (PSNS) at the same time that it promulgates new source performance standards (NSPS). The pretreatment standards for new sources are to be technology based and analogous to the best demonstrated control technology (BADCT) for direct dischargers. New indirect discharging facilities, like new direct discharging facilities, have the opportunity to install the best available demonstrated technology, including process changes, in-plant controls, and end-of-pipe treatment technologies.

The general pretreatment regulations, applicable to existing and new source indirect dischargers (PSES & PSNS) appear in 40 CFR Part 403. These regulations describe the Agency's overall policy for establishing and enforcing pretreatment standards for new and existing users of a POTW as well as the prohibited discharges that apply.

The Agency is proposing zero discharge for the pretreatment standards for drilling fluids and cuttings, produced water, treatment, workover and completion fluids, deck drainage and produced sand. No pretreatment standards are being developed for sanitary and domestic wastes because these wastes are compatible with POTWs.

EPA determines which pollutants to regulate in PSES and PSNS on the basis of whether or not they pass through, interfere with, or are incompatible with the operations of POTWs. This section

describes these pretreatment standard criteria and how they were evaluated with respect to the regulation of the coastal oil and gas industry wastestreams.

Pretreatment standards were not based on the pass-through analysis due to limited data to perform this analysis. The 1993 Coastal Survey and other information reviewed as part of this rulemaking, indicated that these wastes were not currently being discharged into POTWs. However, pretreatment standards are being proposed in the event that the zero discharge standard for direct discharges would encourage operators to discharge into POTWs.

Pretreatment standards for sanitary and domestic wastes are not being developed because they are not expected to cause any upsets with the operation of the POTW. POTWs typically receive these types of wastes from industrial and domestic users.

2.0 INTERFERENCE

EPA's preferred option for produced water is zero discharge everywhere except Cook Inlet. In Cook Inlet, the selected option for produced water is based on improved gas flotation and requires a limitation be met for oil and grease. Produced water consists of a brine usually containing high dissolved solids. In 1985, EPA considered various technologies for treatment of produced waters including biological treatment. Biological treatment was rejected because of the severely difficult problems associated with biologically treating briny wastes (1991 Offshore Development Document, Section IX).[1] If produced water is to be discharged into POTWs, problems with interference or incompatibility could occur. These systems (POTWs, biological treatment systems) can be acclimated to high dissolved solids content, but the incoming stream would have to continue at a constant concentration and flow rate for the system to work properly.[2,3] However, this is uncommon for this industry (variations in flow and concentrations exist, and production processes may cease periodically for a short time to rework and maintain the well). Major interruptions could occur as a result, causing interferences with the operation of POTWs.

The proposed BAT option for drilling fluids and drill cuttings is a zero discharge requirement in all coastal areas. The zero discharge limitation would eliminate the discharge of all pollutants in the waste stream. Drilling fluids and drill cuttings would cause interference with the operation of POTWs due to the high total suspended solids (TSS) content which could not only cause clogging in the piping leading into the POTW, but interfere with the biological treatment systems as well. And as stated in 40

CFR Part 403.5 "National Pretreatment Standards: Prohibited discharges": Solid or viscous pollutants in amounts which will cause obstruction to the flow in the POTW resulting in interference shall not be introduced into POTWs. This can occur with drilling fluids and drill cuttings due to the high solids content (pollutants found in drilling fluids and drill cuttings are listed in Section VII of this document).

The proposed BAT option for deck drainage consists of a prohibition on the discharge of free oil which is equal to the current BPT limitation. EPA determined that technical difficulties are associated with the capture of deck drainage in order to meet a zero discharge requirement. However, for the same reasons that zero discharge is not feasible, it is unlikely that deck drainage would be captured, contained and directed to POTWs for treatment. Additionally, deck drainage, being generated due to rainfall, may consist of unmanageable slugs of sudden influent to POTWs such that it would cause POTW interference. Deck drainage consists of precipitation runoff, miscellaneous leakage and spills, washdown of decks and could potentially contain pollutants that would interfere with the operation of POTWs as in the case of produced water. Thus pretreatment standards are being proposed as equal to zero discharge.

Untreated deck drainage data was collected by the Agency from the three-facility sampling program conducted during 1989. The information is summarized in Section XIII of this document. Also, in 1989, EPA reviewed extensive records of deck drainage data provided by API in the 1990s. Both the Agency's data gathering efforts and API's survey information indicate that the frequency, volume and content of deck drainage is highly variable.

3.0 PASS-THROUGH

Pretreatment standards for existing sources are analogous to BAT and thus a pass through analysis is conducted in order to determine the specific pollutants to be regulated under PSES.

EPA determines whether or not to regulate a pollutant under pretreatment standards on the basis of whether or not the pollutant passes through, interferes with, or is incompatible with the operation of the POTW. EPA evaluates pollutant pass through by comparing the average percentage removed nationwide by well-operated POTWs (those meeting secondary treatment requirements) with the percentage removed by directly discharging facilities applying BAT for that pollutant. When the average percentage removed by well-operated POTWs is less than the percentage removed applying BAT, the pollutant is said to pass through and a pretreatment standard would be required. When the pollutant does not pass through (average percentage removed by well-operated POTWs is greater than the percentage

removed by applying BAT) a pretreatment standard would not be required. However, for the coastal oil and gas industry, insufficient information exists to perform pass through analyses. Rather, pretreatment standards have been developed on the basis of interference.

Pretreatment standards for new sources are analogous to NSPS and thus are being proposed as zero discharge. New facilities have the opportunity to install the best available demonstrated technology and since both standards concern new sources, the technology basis being proposed for NSPS is appropriate for application for PSNS.

4.0 REMOVAL CREDITS

As described previously, many industrial facilities discharge large quantities of pollutants to POTWs where their wastewaters mix with wastewater from other sources such as domestic sewage from private residences and run-off from various sources prior to treatment and discharge by the POTW. Industrial discharges frequently contain pollutants that are generally not removed as effectively by treatment at the POTWs as by the industries themselves.

The introduction of pollutants to a POTW from industrial discharges may pose several problems. These include potential interference with the POTW's operation or pass-through of pollutants if inadequately treated. As discussed, Congress, in section 307(b) of the Act, directed EPA to establish pretreatment standards to prevent these potential problems. Congress also recognized that, in certain instances, POTWs could provide some or all of the treatment of an industrial user's wastewater that would be required pursuant to the pretreatment standard. Consequently, Congress established a discretionary program for POTWs to grant "removal credits" to their indirect dischargers. The credit, in the form of a less stringent pretreatment standard, allows an increased concentration of a pollutant in the flow from the indirect discharger's facility to the POTW.

Section 307(b) of the CWA establishes a three-part test for obtaining removal credit authority for a given pollutant. Removal credits may be authorized only if (1) the POTW "removes all or any part of such toxic pollutant," (2) the POTW's ultimate discharge would "not violate that effluent limitation, or standard which would be applicable to that toxic pollutant if it were discharged" directly rather than through a POTW and (3) the POTW's discharge would "not prevent sludge use and disposal by such [POTW] in accordance with section [405]...." Section 307(b).

EPA has promulgated removal credit regulations in 40 C.F.R. Part 403.7. The United States Court of Appeals for the Third Circuit has interpreted the statute to require EPA to promulgate comprehensive sewage sludge regulations before any removal credits could be authorized. NRDC v. EPA, 790 F.2d 289, 292 (3rd Cir. 1986) cert. denied. 479 U.S. 1084 (1987). Congress made this explicit in the Water Quality Act of 1987 which provided that EPA could not authorize any removal credits until it issued the sewage sludge use and disposal regulations required by section 405(d)(2)(a)(ii).

Section 405 of the CWA requires EPA to promulgate regulations that establish standards for sewage sludge when used or disposed for various purposes. These standards must include sewage sludge management standards as well as numerical limits for pollutants that may be present in sewage sludge in concentrations which may adversely affect public health and the environment. Section 405 requires EPA to develop these standards in two phases. On November 25, 1992, EPA promulgated the Round One sewage sludge regulations establishing standards, including numerical pollutant limits, for the use or disposal of sewage sludge. 58 Fed. Reg. 9248. EPA established pollutant limits for ten metals when sewage sludge is applied to land, for three metals when it is disposed of on a surface disposal site and for seven metals and a total hydrocarbon operational standard, a surrogate for organic pollutant emissions, when sewage sludge is incinerated. These requirements are codified at 40 C.F.R. Part 503.

The Phase One regulations partially fulfilled the Agency's commitment under the terms of a consent decree that settled a citizens suit to compel issuance of the sludge regulations. Gearhart, et al. v. Reilly, Civil No. 89-6266-JO (D.Ore). Under the terms of that decree, EPA must propose and take final action on the Round Two sewage sludge regulations by December 15, 2001.

At the same time EPA promulgated the Round One regulations, EPA also amended its pretreatment regulations to provide that removal credits would be available for certain pollutants regulated in the sewage sludge regulations. See 58 Fed. Reg. at 9386. The amendments to Part 403 provide that removal credits may be made potentially available for the following pollutants:

(1) If a POTW applies its sewage sludge to the land for beneficial uses, disposes of it on surface disposal sites or incinerates it, removal credits may be available, depending on which use or disposal method is selected (so long as the POTW complies with the requirements in Part 503). When sewage sludge is applied to land, removal credits may be available for ten metals. When sewage sludge is disposed of on a surface disposal site, removal credits may be available for three metals. When the

sewage sludge is incinerated, removal credits may be available for seven metals and for 57 organic pollutants. See 40 C.F.R. § 403.7(a)(3)(iv)(A).

(2) In addition, when sewage sludge is used on land or disposed of on a surface disposal site or incinerated, removal credits may also be available for additional pollutants so long as the concentration of the pollutant in sludge does not exceed a concentration level established in Part 403. When sewage sludge is applied to land, removal credits may be available for two additional metals and 14 organic pollutants. When the sewage sludge is disposed of on a surface disposal site, removal credits may be available for seven additional metals and 13 organic pollutants. When the sewage sludge is incinerated, removal credits may be available for three other metals. See 40 C.F.R. § 403.7(a)(3)(iv)(B).

3) When a POTW disposes of its sewage sludge in a municipal solid waste landfill that meets the criteria of 40 C.F.R. Part 258 (MSWLF), removal credits may be available for any pollutant in the POTW's sewage sludge. See 40 C.F.R. § 403.7(a)(3)(iv)(C). Thus, given compliance with the requirements of EPA's removal credit regulations,[a] following promulgation of the pretreatment standards being proposed here, removal credits may be authorized for any pollutant subject to pretreatment standards if the applying POTW disposes of its sewage sludge in a MSWLF that meets the requirements of 40 C.F.R. Part 258. If the POTW uses or disposes of its sewage sludge by land application, surface disposal or incineration, removal credits may be available for the following metal pollutants (depending on the method of use or disposal): arsenic, cadmium, chromium, copper, iron, lead, mercury, molybdenum, nickel, selenium and zinc. Given compliance with section 403.7, removal credits may be available for the following organic pollutants (depending on the method of use or disposal) if the POTW uses or disposes of its sewage sludge: benzene, 1,1-dichloroethane, 1,2-dibromoethane, ethylbenzene, methylene chloride, toluene, tetrachloroethene, 1,1,1-trichloroethane, 1,1,2-trichloroethane and trans-1,2-dichloroethene.

Some facilities may be interested in obtaining removal credit authorization for other pollutants being considered for regulation in this rulemaking for which removal credit authorization would not otherwise be available under Part 403. Under sections 307(b) and 405 of the CWA, EPA may authorize

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[a] Under Section 403.7, a POTW is authorized to give removal credits only under certain conditions. These include applying for, and obtaining, approval from the Regional Administrator (or Director of a State NPDES program with an approved pretreatment program), a showing of consistent pollutant removal and an approved pretreatment program. See 40 C.F.R. § 403.7(a)(3)(i), (ii), and (iii).

removal credits only when EPA determines that, if removal credits are authorized, that the increased discharges of a pollutant to POTWs resulting from removal credits will not affect POTW sewage sludge use or disposal adversely. As discussed in the preamble to amendment to the Part 403 regulations (58 Fed. Reg. 9382-83), EPA has interpreted these sections to authorize removal credits for a pollutant only in one of two circumstances. Removal credits may be authorized for any categorical pollutant 1) for which EPA have established a numerical pollutant limit in Part 503; or 2) which EPA has determined will not threaten human health and the environment when used or disposed of in sewage sludge. The pollutants described in paragraphs (1) - (3) above include all those pollutants that EPA either specifically regulated in Part 503 or evaluated for regulation and determined would not adversely affect sludge use and disposal.

Consequently, in the case of a pollutant for which EPA did not perform a risk assessment in developing the Phase One sewage sludge regulations, removal credit for pollutants will only be available when the Agency determines either a safe level for the pollutant in sewage sludge or that regulation of the pollutant is unnecessary to protect public health and the environment from the reasonably anticipated adverse effects of such a pollutant.[b] Therefore, any person seeking to add additional categorical pollutants to the list for which removal credits are now available would need to submit information to the Agency to support such a determination. The basis for such a determination may include information showing the absence of risks for the pollutant (generally established through an environmental pathway risk assessment such as EPA used for Phase One) or data establishing the pollutant's presence in sewage sludge at low levels relative to risk levels or both. Parties, however, may submit whatever information they conclude is sufficient to establish either the absence of any potential for harm from the presence of the pollutant in sewage sludge or data demonstrating a "safe" level for the pollutant in sludge. Following submission of such a demonstration, EPA will review the data and determine whether or not it should propose to amend the list of pollutants for which removal credits would be available.

EPA has already begun the process of evaluating a number of pollutants for adverse potential to human health and the environment when present in sewage sludge. In May, 1993, pursuant to the terms of the consent decree in the Gearhart case, the Agency notified the United States District Court for the

[b] In the Round One sewage sludge regulation, EPA concluded, on the basis of risk assessments, that certain pollutants (see Appendix G to Part 403) did not pose an unreasonable risk to human health and the environment and did not require the establishment of sewage sludge pollutant limits. As discussed above, so long as the concentration of these pollutant in sewage sludge are lower than a prescribed level, removal credits are authorized for such pollutants.

District of Oregon that, based on the information then available at that time, it intended to propose 31 pollutants for regulation in the Round Two sewage sludge regulations. These are acetic acid (2, 4, -dichlorophenoxy), aluminum, antimony, asbestos, barium, beryllium, boron, butanone (2-), carbon disulfide, cresol (p-), cyanides (soluble salts and complexes), dioxins/dibenzofurans (all monochloro to octochloro congeners), endsulfan-II, fluoride, manganese, methylene chloride, nitrate, nitrite, pentachloro-nitrobenzene, phenol, phthalate (bis-2-ethylexyl), polychlorinated biphenyls (co-planar), propanone (2-), silver, thallium, tin, titanium, toluene, trichlorophenoxyacetic acid (2, 4, 5-), trichlorphenoxypropionic acid ([2 - (2, 4, 5-)], and vanadium.

The Round Two regulations are not scheduled for proposal until December, 1999 and promulgation in December 2001. However, given the necessary factual showing, as detailed above, EPA could conclude before the contemplated proposal and promulgation dates that regulation of some of these pollutants is not necessary. In those circumstances, EPA could propose that removal credits should be authorized for such pollutants before promulgation of the Round Two sewage sludge regulations. However, given the Agency's commitment to promulgation of effluent limitations and guidelines under court-supervised deadlines, it may not be possible to complete review of removal credit authorization requests by the time EPA must promulgate these guidelines and standards.

REFERENCES

1. U.S. EPA, Development Document for Effluent Limitation Guidelines and Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category, EPA 440/1-91/055, March 1991.

2. Organic Chemicals, Plastics, and Synthetic Fibers Regulation, Monsanto Comments section 5, submitted December 13, 1985.

3. Ray and Engelhardt, Produced Water, Technological/Environmental Issues and Solutions - Environmental Science Research, Volume 46, Tellez and Nirmalakhandan, "Bioreclamation of Oilfield Produced Wastewaters: Characterization and Feasibility Study", 1992.

SECTION XVI

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. EPA evaluated the non-water quality environmental impacts on a regional basis because the different regions each have their own unique considerations. This section discusses the non-water quality environmental impacts associated with these regulations for each waste stream, and other factors such as safety.

Table XVI-1 presents the non-water quality impacts in terms of air emissions and energy requirements for the options selected for proposal (see Sections X, XI, and XII).

2.0 DRILLING WASTES - COOK INLET

The control technology basis for compliance with the options considered for the drilling fluids and drill cuttings waste streams in Cook Inlet are transportation of drilling wastes to shore for disposal and grinding followed by injection at the platform. Therefore, in addition to energy requirements and air emissions, adequate onshore disposal capacity for these wastes is critical in assessing the options. Safety and impacts of marine traffic on coastal waterways were other factors also considered.

2.1 ENERGY REQUIREMENTS AND AIR EMISSIONS

Energy requirements and air emissions resulting from the operation of equipment required for transportation and disposal such as boats, cranes, trucks, and earth-moving equipment, and for grinding and injection at the platform were estimated by using emission factors relating the production of air

TABLE XVI-1
AIR EMISSIONS AND ENERGY REQUIREMENTS FOR THE PROPOSED OPTIONS BY WASTESTREAMS

Waste Stream Option	Fuel (BOE/yr)[a]		Air Emissions (tons/yr)	
	BAT	NSPS	BAT	NSPS
Drilling Wastes				
Option 1: Zero Discharge; Cook Inlet Tox. Limit of 30,000 ppm SPP	0	0	0	0
Option 2: Zero Discharge; Cook Inlet Tox. Limit of 1,000,000 ppm SPP	1,738	0	8.69	0
Option 3: Zero Discharge All	2,285	0	12.47	0
Produced Water				
Option 1: BPT All	0	0	0	0
Option 2: Flotation All	28,595	1,712	258.40	17.31
Option 3: Zero Discharge; Cook Inlet BPT	258,946	5,948	2,799.32	63.67
Option 4: Zero Discharge; Cook Inlet Flotation	260,376	5,948	2,801.00	63.67
Option 5: Zero Discharge All	343,759	5,948	2,899.14	63.67
Treatment, Workover, and Completion Fluids				
Option 1: BPT	0	0	0	0
Options 2a and 2b[b]: Zero Discharge or Gas Flotation	1,138	155	12.20	1.66

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

[b] Energy requirements and air emissions were calculated only for the portion of TWC fluids that would be commercially disposed as described in the cost analysis in Section XII.

pollutants to time of equipment operation and amount of fuel consumed. The differential increases in fuel requirements and air emissions resulting from compliance with each control option are presented in Table XVI-2. Detailed calculations of the totals presented in Table XVI-2 are included in Appendix XVI-1. The volumes reported in this table and the following pertinent sections are based on total volume of drilling wastes that would require disposal under each option from industry-provided drilling activity data projected over the 7 years following promulgation of this rule (see Section X, for drilling activity schedule).

TABLE XVI-2
AIR EMISSIONS AND ENERGY REQUIREMENTS FOR DISPOSAL OF DRILLING FLUIDS AND DRILL CUTTINGS IN COOK INLET
(from Appendix XVII-1)

Options	Waste Volume[a] (bbl)			Air Emissions (tons/yr)[c]	Fuel Requirements (BOE/yr)[d]
	Barged[b]	Injected	Total		
Option 1: Zero Discharge; Cook Inlet Tox. Limit of 30,000 ppm	0	0	0	0	0
Option 2: Zero Discharge; Cook Inlet Tox. Limit of 1,000,000 ppm	93,984	0	93,984	8.69	1,738
Option 3: Zero Discharge All	422,780	130,066	552,846	12.47	2,285

[a] The volume of wastes represents cumulative values for the 7 year period from 1996 through 2002.
[b] Wastes barged are those transported via barge (and/or supply boat) to shore and disposed of in landfills.
[c] Annual air emissions represent the total estimated emissions divided by seven.
[d] BOE (barrels of oil equivalents) is the sum of total diesel volume required and total natural gas volume converted to equivalent oil volume by the factor: 1,000 scf = 0.178 bbl oil. Values shown are the total estimated BOE divided by seven.

2.1.1 Energy Requirements

Energy requirements for the treatment options considered for this rule were calculated by identifying those activities necessary to support onshore disposal of drilling wastes and injection at the platform. The only landfill available for disposal of drilling wastes in Cook Inlet is privately owned and operated. Access to this landfill is limited to only the two operators that own and operate it. The Kustatan landfill, which is located on the west side of Cook Inlet, is only operated for four months in the summer because of climate conditions that are specific to Cook Inlet. Drilling wastes are first transported by supply boats from the platform to a temporary storage facility on the east side of Cook Inlet to be unloaded and temporarily stored. Barges are used to transport drilling wastes from the east to the west side of Cook Inlet. Trucks are then used to transport the muds and cuttings to the landfill.[1] For the other operators in Cook Inlet, the technology basis for Option 3 (zero discharge) is injection at the platform, and transportation and disposal to the lower contiguous United States for Option 2 (discharge, provided limitations on free oil, diesel oil, cadmium, mercury and toxicity are met). Transportation of drilling wastes to the lower 48 states is by boat to the marine terminal on the east side of Cook Inlet and by truck to a commercial disposal facility in Idaho.[2]

Fuel requirements and air emissions were estimated for the following activities associated with the transportation and disposal of drilling wastes in Cook Inlet:

- Supply boats and barges to transport the drilling wastes.
- Crane operation at the drilling sites and marine transfer stations to facilitate loading and unloading of the wastes.
- Trucks to transport the wastes from the marine terminal to the onshore disposal site.
- Earth-moving equipment at the disposal site to facilitate land spreading and landfill operations.
- Injection equipment for injection at the platform: transfer and injection pumps, grinder, agitator, and conveying equipment.

Table XVI-3 summarizes the diesel fuel requirements for the transportation and disposal of drilling wastes either to the facility at Kustatan or to a commercial facility. Detailed calculations for the operating parameters can be found in Appendix XVI-1. 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, and with injection at the platform of drilling fluids and drill cuttings.

2.1.1.1 Supply Boats and Barges

In order to estimate the fuel requirements associated with marine transportation of drilling wastes, energy requirements for supply boats and barges were assumed to be the same. 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
- Supply boat capacity and usage
- Auxiliary electrical generation.

This section details the assumptions made to estimate the fuel usage for each of these activities.

TABLE XVI-3
FUEL REQUIREMENTS FOR LAND DISPOSAL OF DRILLING WASTES IN COOK INLET
(from Appendix XVII-1)

Source	Option 2			Option 3[a]		
	Operating Parameter[b]	Diesel		Operating Parameter[b]	Diesel	
		GAL[b]	BOE/yr[c]		GAL[b]	BOE/yr[c]
Number Supply Boat Trips	51.75	38,000	129	233	170,910	581
Number Barge Trips	26.42	5,280	18	155.43	31,090	106
Auxiliary Generator (hrs/trip)	48	7,450	25	48	33,520	114
Crane (hrs)	768	6,390	22	3,699	30,810	105
Number Truck Trips	749	433,730	1,475	4,404	11,010	37
Wheel-Tractor (hrs)	440	730	2.5	360	600	2
Track-type Dozer (hrs)	880	19,360	66	720	15,840	54
Total	--	**510,940**	**1,738**	--	**293,780**	**999**

[a] Additional BOEs expended for injection are not shown on this Table for Option 3.
[b] Represents the cumulative values for the 7 year period from 1996 to 2002.
[c] BOE (barrels of oil equivalent) per year is the total diesel volume required converted to equivalent oil volume by the factor: 1 BOE = 42 gal. Values shown are the estimated BOE divided by seven.

- 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.[3]
  - Fuel Consumption: 130 gallons of diesel per hour.[4]
  - Boat Speed: The average supply boat speed during transit is 10 knots.[3] The average barge speed is 6 mph.[5]
  - Average Distance: The average round-trip distance for the supply boats to go from platforms to the dock on the east side of Cook Inlet is 50 miles. The average round-trip distance for barges to go to the west side of Cook Inlet is 50 miles (see Appendix XVI-1).
- Maneuvering Fuel Consumption: Supply boats are estimated to maneuver at the platform for an average of one hour per visit. The maneuvering fuel use factor is 15 percent of full throttle fuel consumption.[6]
- Idling Fuel Consumption: Due to ocean current and wave action, boats must maintain engines idling while at platforms unloading empty cuttings boxes and loading drilling fluids and boxes. The total average time idling on station at the drill site for loading is 5.7 hours per visit. This is based on the crane operating time of 4.7 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 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 in port.

  The average in port time for unloading drilling fluids and drill cuttings, tank cleanout, and demurrage is 24 hours per supply boat trip.[3] The boat engines would be shutdown during this period. EPA assumed that while in port, 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[6], and consumes 6 gallons of diesel fuel per hour.[3]

- Supply Boat Capacity and Usage: An offshore supply boat typically has a deck space of 130 feet long by 28 feet wide and can store approximately 227 cuttings boxes (8 barrel) on deck.[7]

  The drilling platform or rig has sufficient available deck area to store excess drilling fluids without affecting drilling operations.[8] The cuttings generation rate is the highest during the first phase of drilling due to the large borehole diameter, and the volume of drill cuttings are the limiting factor for boat capacity. During the last stages of drilling, the drill cuttings generation rate subsides as the borehole diameter decreases. 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.

  EPA estimated that for Option 3, a total of 233 boat trips would be required for drilling operations in Cook Inlet. For Option 2, a total of 51.75 boat trips would be required to transport drilling waste (see Table XVI-3). Appendix XVI-1 presents the detailed calculations used to arrive at these values.

- Barge Capacity and Usage: Barges are required to transport the combined drilling wastes from the east side of Cook Inlet to the west side for disposal. A typical barge that operates in Cook Inlet has a deck space of 150 feet long by 45 feet wide and can store approximately 340 boxes cuttings boxes (8 barrels) on deck.[9] Distance from the east side of Cook Inlet to the west side, near the Trading Bay facility was estimated to be approximately 25 miles. Boxes are unloaded on the beach near the Trading Bay facility.

2.1.1.2 Cranes

Cranes used to load and unload cuttings boxes at the drill site and in port 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.[6]
- Fuel Consumption: 8.33 gallons of diesel fuel per hour.[4]
- Lift Capacity: 10 lifts per hour.[3] The unloading of 227 empty cuttings boxes or loading 227 full cuttings boxes on the supply boat requires a minimum of 5.7 hours (based on an assumed 4 boxes per lift).

2.1.1.3 Trucks

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: 10-12 boxes of drilling fluids and drill cuttings.[10] Capacity used for combined wastes is 96 bbl for short distance and 65 bbl for long distance.[2]
- Fuel Consumption: 4 miles per gallon of diesel fuel.[3]
- Distance: The average round trip distance between the barge docking area and the disposal site is estimated at 10 miles for operators disposing of the drilling wastes on the west side of Cook Inlet (see Appendix XVI-1). For all the other operators, an average round trip of 5,000 miles is used.[2]

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 estimated 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 are 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.[3]
- 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.[3]

2.1.1.5 Grinding and Injection Equipment

The grinding and injection equipment, which constitutes the technology basis for the zero discharge option for those operators that do not have access to a landfill in Cook Inlet, is comprised of the cuttings processing equipment and of the injection pumps. The cuttings processing equipment power and fuel requirements were estimated based on the following horsepower requirements[11]:

Grinder (500 KVA Transformer):

2-150 HP motors at 480V
1-10 HP Auger motor
Additional lights/heating 100 KVA

Cutting Transfer Equipment:

2-30 HP Disk flow motors
1-10 HP Hydraulic pump
Steam as required

Dewatering Unit:

2-5 HP Shaker motors
1-10 HP Agitator
1-45 HP Dewatering centrifuge
1-10 HP Underflow pump
2-30 HP Disk flow pumps
1-30 HP Galliger pump
4-1/2 HP motors

The power and fuel requirements for the injection equipment were estimated based on one 500-hp injection pump rated at 5 bbl/min.[1]

The equipment usage (hrs per well) was estimated based on the average time required to drill a new well or a recompletion. Details of these calculations are presented in Section X, Appendix X-1.

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).[12] Table XVI-4 summarizes the fuel consumption for the grinding and injection system. Details for these calculations are presented in Appendix XVI-1.

TABLE XVI-4

FUEL REQUIREMENTS FOR GRINDING AND INJECTION
(from Appendix XVII-1)

	Number Wells[a]	Horsepower Reqmt's (hp/well)	Operation (hrs/well)	Total Usage[a] (hp-hr)	Natural Gas Usage	
					scf[a]	BOE/yr[b]
Cuttings Processing Equipment						
New Wells	9	747	733	4,927,959	46,815,611	1,190
Recompletions	1	747	240	179,280	1,703,160	43
Injection Equipment						
New Wells	9	500	47.37	213,157	2,024,992	51.4
Recompletions	1	500	7.24	3,620	34,391	0.9
Total for Grinding and Injection Equipment						
New Wells	9	--	--	5,141,116	48,840,603	1,242
Recompletions	1	--	--	182,900	1,737,551	44
Total	**10**	--	--	**5,324,016**	**50,578,154**	**1,286**

[a] These are cumulative values for the 7 year period from 1996 through 2002.
[b] BOE (barrels of oil equivalent) per year is the volume of natural gas converted to equivalent oil volume by the factor: 1,000 scf = 0.178 bbl oil. The values shown are the estimated BOE divided by seven.

2.1.2 Air Emissions

The total air emissions for both options presented in Table XVI-1 have been calculated using the total system utilization rate (horsepower-hour or miles traveled) and emission factors developed for different types of engines and fuels used. Emission factors were determined for uncontrolled sources. The term "uncontrolled" refers to the emissions resulting from a source which does not utilize add-on control technologies to reduce the emissions of specific pollutants. The use of "uncontrolled" emission factors provides conservative estimates of total emissions resulting from disposal of drilling wastes in Cook Inlet. Table XVI-5 presents the uncontrolled emissions factors for different types of diesel engines and natural gas driven engines used to develop air emissions from activities related to onshore disposal and injection of wastes covered by this regulation. Note that the factors are not all based on the same units. Detailed calculations of the air emissions from each type of engine used are presented in Appendix XVI-1.

Table XVI-6 summarizes the contribution of air pollutants of each type of activity associated with disposal of drilling wastes in Cook Inlet. For example, a total of 233 supply boat trips are needed to transport the volume of drilling wastes under the zero discharge option. For a boat in transit, an NO_x

TABLE XVI-5

UNCONTROLLED EMISSION FACTORS[12,13,a]

Equipment		Nitrogen Oxides (NO_x)	Total Hydrocarbons (THC)	Sulfur Dioxide (SO_2)	Carbon Monoxide (CO)	Total Suspended Particulates (TSP)
Supply Boats (lb/1,000 gal)	Idle	419.6	22.6	28.48	59.8	33.0
	Transit	391.7	16.8	28.48	78.3	33.0
Cranes (g/bhp-hr)		14.0	1.12	0.931	3.03	1.0
Trucks (g/mile)		11.44	2.53	NA	8.67	NA
Wheel Tractor (lb/hr)		1.269	0.188	0.090	3.59	0.136
Track-type Dozer (lb/hr)		0.827	0.098	0.076	0.201	0.058
Auxiliary Diesel Engines (lb/1,000 gal)		469	37.5	31.2	102	33.5
Natural Gas Engines (g/hp-hr)	Reciprocating	11.0	4.4	0.002[b]	1.4	NA
	Turbine	1.7	0.055	0.002[b]	0.05	NA

[a] All values shown are cumulative totals for the 7 year period from 1996 through 2002.
[b] 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 2,000 g/10^6 scf[12].
NA = Not Applicable

emission factor of 391.7 lb/1,000 gal of diesel was used. The total diesel fuel requirement for supply boats in transit was estimated to be 131,590 gal (see Appendix XVI-1). The total nitrogen oxides emissions resulting from this activity are:

$$(391.7 \text{ lb}/1000 \text{ gal})\text{x}(131{,}590 \text{ gal})\text{x}(1 \text{ ton}/2000 \text{ lb}/7 \text{ yrs}) = 3.68 \text{ tons/yr}$$

The operation of the grinding and injection equipment to dispose of the drilling wastes under the zero discharge option require a total power of 5,324,016 hp-hr. For a natural gas driven turbine, an NO_x emission factor of 1.7 g/hp-hr was used. The total nitrogen oxides emissions resulting from this activity are:

$$(1.7 \text{ g/hp-hr})\text{x}(5{,}324{,}016 \text{ hp-hr})\text{x}(1 \text{ ton}/908{,}000 \text{ g}/7 \text{ yrs}) = 1.42 \text{ tons/yr}$$

TABLE XVI-6
AIR EMISSIONS ASSOCIATED WITH PROPOSED OPTIONS FOR EXISTING SOURCES FOR DRILLING WASTES IN COOK INLET
(from Appendix XVII-1)

	NOx	THC	SO2	CO	TSP	Total
Option 2 (tons/yr)						
Supply boats	1.245	0.062	0.088	0.236	0.101	1.733
Barges	0.148	0.006	0.011	0.026	0.012	0.203
Supply Boat Cranes	0.176	0.014	0.012	0.038	0.013	0.252
Barge Cranes	0.054	0.004	0.004	0.012	0.004	0.077
Trucks	3.123	0.691	0.000	2.367	0.000	6.180
Wheel Tractor	0.040	0.006	0.003	0.113	0.004	0.166
Dozer/Loader	0.052	0.006	0.005	0.013	0.004	0.079
Grinding/Processing Equipment	0.000	0.000	0.000	0.000	0.000	0.000
Injection Equipment	0.000	0.000	0.000	0.000	0.000	0.000
Total	**4.84**	**0.79**	**0.12**	**2.80**	**0.14**	**8.69**
Option 3 (tons/yr)						
Supply boats	5.598	0.280	0.397	1.064	0.456	7.795
Barges	0.870	0.037	0.063	0.174	0.073	1.217
Supply Boat Cranes	0.792	0.063	0.053	0.171	0.057	1.135
Barge Cranes	0.317	0.025	0.021	0.069	0.023	0.454
Trucks	0.079	0.018	0.000	0.060	0.000	0.157
Wheel Tractor	0.033	0.005	0.002	0.092	0.003	0.136
Dozer/Loader	0.043	0.005	0.004	0.010	0.003	0.065
Grinding/Processing Equipment	1.366	0.044	0.002	0.040	0.000	1.452
Injection Equipment	0.058	0.002	0.000	0.002	0.000	0.062
Total	**9.15**	**0.48**	**0.54**	**1.68**	**0.61**	**12.47**

2.2 SOLID WASTE GENERATION AND MANAGEMENT

The regulatory options considered for this rule will not cause generation of additional solids as a result of the treatment technology. However, as already discussed, spent drilling fluids and the

associated cuttings would be disposed of at onshore disposal sites or injected underground to comply with the proposed options.

There are currently no commercially operating disposal sites in Cook Inlet accepting offshore drilling wastes. The only land disposal facility accepting drilling wastes from Cook Inlet operations is privately owned and operated. The lack of commercial disposal sites would require operators that do not own a land disposal facility to either transport the drilling wastes to the nearest known commercial disposal facility located in Idaho or inject the drilling wastes into underground formations.

Capacity estimates for the disposal facility at Kustatan show that this landfill has enough storage capacity to accept the volume of drilling wastes (422,780 bbl) that would be generated under the no discharge limitation, from the platforms that it now serves.[14] The solid waste disposal facility at Kustatan has 16 modules. Each module consists of four cells, each with a storage capacity of 9,620 bbl.[15] The total capacity is 615,680 bbl (16 x 4 x 9,620). To date, only two cells have been used, leaving an available capacity of 596,440 bbl. The volume of drilling wastes generated under the zero discharge option represents about 71 percent of the excess available capacity at Kustatan.

Under the limitations of Option 2, the total estimated volume of drilling wastes requiring land disposal is 93,984 bbl (see Table XVI-2). Of this total volume of drilling wastes, 22,112 bbl over the next 7 years, or 3,159 bbl/yr (see Section X) were estimated for disposal to commercial facilities in the lower 48 states. Because of this small volume of wastes, EPA assumed that there is ample landfill disposal capacity in the lower 48 states, such as Idaho and Oregon. For example, the landfill in Idaho is a RCRA permitted facility with a capacity of 120 tons/yr to the year 2018.[16] The landfill in Oregon is a RCRA permitted facility with an available capacity of about 4,000,000 bbl.[17]

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 Cook Inlet

EPA estimates that a total of 233 boat trips would be required to comply with a zero discharge requirement. This estimate is for all drilling that will take place in the next 7 years after expected

promulgation of this rule. Thus, the 233 boat trips equate on the average to approximately 33 additional boat trips per year. EPA does not expect this to cause traffic problems in Cook Inlet.

In fact, it will serve to provide service companies with additional work. EPA has not estimated expected job gains associated with this rulemaking. However, job gains could be realized due to increased boat trips.

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 in Cook Inlet.[18]

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 XVI-7 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".[19] 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 of 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.

TABLE XVI-7

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

- 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.
- 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 in Cook Inlet are used for platforms while barges are used in summer to transport drilling wastes to Kustatan for disposal. Containers or boxes are used to hold the excess and/or used muds and cuttings and have an approximate capacity of 12 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.

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 evaluated the potential for degradation of underground sources of drinking water. The following is a description of the non-water quality environmental impacts for the Gulf of Mexico and Cook Inlet, and a summary of the estimated impact levels for each option considered.

3.1 ENERGY REQUIREMENTS AND AIR EMISSIONS

Annual energy requirements and resulting air emissions for the control options considered by EPA are presented in Table XVI-8 for both new and existing sources. Estimates are presented incremental to current BPT limitations and thus represent the expected increase above current emissions levels and energy consumption. Detailed calculations of the totals in Table XVI-8 are provided in Appendix XVI-2.

As can be seen from Table XVI-8, the option requiring zero discharge of all produced water greatly increases air emissions and fuel requirements as compared to the "gas flotation all" option. This is due primarily to the energy required to operate the injection pumps.

3.1.1 Energy Requirements

This section provides a detailed discussion on the development of fuel requirements for each treatment technology in both regions, based on the volume of produced water discharged from each facility type. The methodology which is described in the following sections, was applied to estimate energy requirements for both existing and new sources.

TABLE XVI-8

NON-WATER QUALITY ENVIRONMENTAL IMPACTS PRODUCED WATER
(from Appendix XVII-2)

Option	Fuel Requirements (BOE/yr)[a]		Air Emissions (tons/year)	
	BAT	NSPS	BAT	NSPS
Option 1: BPT All	0	0	0	0
Option 2: Flotation All	28,595	1,712	258.40	17.31
Option 3: Zero Discharge; Cook Inlet BPT	258,946	5,948	2,799.32	63.67
Option 4: Zero Discharge; Cook Inlet Flotation	260,376	5,948	2,801.00	63.67
Option 5: Zero Discharge All	343,759	5,948	2,899.14	63.67

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

3.1.1.1 Small-Volume Facilities - Gulf of Mexico

As described in Section XI, small-volume facilities in the Gulf of Mexico are those facilities that will transport the produced water to a commercial facility for disposal under any option. Energy requirements for these facilities were calculated by identifying those activities necessary to support disposal of produced water. Those activities requiring fuel consumption include:

- Barges to transport the produced water from facilities with water access to the commercial facility. One barge of 3,000 bbl capacity is used to service multiple facilities.
- Trucks to transport the produced water from facilities with land access to a commercial facilities.
- Vacuum pumps and compressors are only used at the commercial facility to unload the barges. Barge loading is by gravity feed.

The following sections present the assumptions and the methodology used to estimate the energy required by various transportation and handling activities associated with commercial disposal of produced water from small-volume facilities in the Gulf of Mexico.

3.1.1.1.1 Facilities With Water Access

The fuel usage due to operation of barges to transport produced water to commercial facilities for disposal was calculated by estimating the fuel consumption required by tugs to pull the barges, the distance barges have to travel, and the fuel consumption by vacuum pumps and compressors to unload the barges. The location of each small-volume facility with water-access was determined from oil and gas maps. The number of boat trips was estimated based on the onsite storage capacity of each facility, the distances between facilities, the distance from port to the first facility, and the distance from the last facility to the commercial disposal facility. This section details the assumptions made to estimate the fuel usage for each of these activities.

- Barge capacity is 3,000 bbl. Each barge will service multiple facilities to full capacity.
- Distances between facilities were estimated to be on the average 10 miles.[20]
- Distance from port to first facility was assumed to be 50 miles.[21]
- Traveling speed for barge and tug is 6 miles per hour.[5]
- Time to dock at each facility is 1 hour.[21]
- Time to leave each facility is 15 minutes.[22]
- The maximum time to load or unload a barge is 8 hrs.[5]
- Distance from last facility to the disposal facility is 50 miles.[21]
- Fuel consumption for the tug is 24 gal/hr.[4] Tug engines are shut-down if the time to load/unload the barge is greater than 30 minutes.
- A 4-inch vacuum pump with a pumping capacity of 60,000 gal/hr and compressor will be used to unload the barge. The average diesel fuel consumption for the pump and compressor is 0.6 gal/hr and 3.5 gal/hr, respectively.[4]

The annual diesel fuel consumption associated with transportation of produced water from small-volume facilities with water access to commercial disposal facilities was calculated based on yearly barge trip cycles. A total of 51 barge cycles per year was estimated based on the number of small-volume facilities, each facility's onsite storage capacity, and the round-trip distances traveled by a barge to and from port.[22] Table XVI-9 summarizes the fuel consumption for all existing small-volume facilities with water access for both produced water control options.

TABLE XVI-9

ENERGY REQUIREMENTS FOR COMMERCIAL DISPOSAL OF PRODUCED WATER FROM EXISTING SMALL-VOLUME WATER ACCESS FACILITIES IN THE GULF OF MEXICO

Option	Number Small-Vol. Facilities	Vol. PW Barged bbl/yr)	Diesel Fuel Consumption (gal/yr)				Total Fuel (BOE/yr)*
			Tug&Barge	Pump	Compressor	Total	
Gas Flotation	9	65,335	204,752	64.3	374.9	205,191	4,886
Zero Discharge	12	155,490	224,786	64.3	374.9	225,225	5,363

* BOE (barrels of oil equivalent) per year is the total diesel volume required converted to equivalent oil volume by the factor: 1 BOE = 42 GAL.

3.1.1.1.2 Facilities With Land Access

The fuel usage due to operation of trucks to transport produced water to commercial facilities for disposal was calculated by estimating the fuel consumption required by trucks, and the distance trucks have to travel to a commercial injection facility. The number of truck-trips was estimated based on each facility's onsite storage capacity. This section details the assumptions made to estimate the fuel usage for each of these activities.

- Truck capacity was assumed to be 119 bbl.[13]
- Truck diesel fuel usage was assumed to be 4 miles per gallon.[13]
- Roundtrip distance between each facility and the commercial disposal facility was estimated to be approximately 120 miles (see Appendix XI-1).

The annual diesel fuel consumption associated with transportation of produced water from small-volume facilities with land access to commercial disposal facilities was calculated based on the number of truck round-trips (see Appendix XVI-2). Table XVI-10 summarizes the fuel consumption for all small-volume facilities with land access, for both produced water control options.

TABLE XVI-10

ENERGY REQUIREMENTS FOR COMMERCIAL DISPOSAL OF PRODUCED WATER FROM EXISTING SMALL-VOLUME LAND ACCESS FACILITIES IN THE GULF OF MEXICO

Option	Number Small-Vol. Facilities	Vol. PW Barged (bbl/yr)	Diesel Fuel Consumption (gal/yr)					Total BOE/yr*
			Truck	Tug&Barge	Pump	Compressor	Total	
Gas Flotation	41	457,710	230,880	0	0	0	230,880	5,497
Zero Discharge	38	377,045	190,200	0	0	0	190,200	4,529

* BOE (barrels of oil equivalent) per year is the total diesel volume required converted to equivalent oil volume by the factor: 1 BOE = 42 GAL.

3.1.1.2 Medium/Large-Volume Facilities - Gulf of Mexico

As described in Section XI, medium/large-volume facilities in the Gulf of Mexico are those facilities that will treat and discharge or inject the produced water onsite. Energy requirements for these facilities were calculated by identifying those activities necessary to support the treatment and injection of produced water.

The following sections present the assumptions and the methodology used to estimate the energy required by the two control options for produced water from medium/large-volume facilities in the Gulf of Mexico.

3.1.1.2.1 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 including the feed pumps will be run by electricity. The electric power will be supplied by natural gas driven generators.

- For existing sources, fuel requirements and air emissions for gas flotation represent only the additional electricity required above 25 horsepower that must be generated for operation of gas flotation systems.

- For new sources, the fuel requirements and air emissions represent the electricity required by each gas flotation system as an add-on to BPT treatment.

Energy requirements for commercially available gas flotation systems were obtained from equipment vendors for systems of four different sizes ranging in treatment capacity from 1,700 to 77,000 barrels per day (BPD).[24] Electricity requirements in kilowatts (kW) for each unit were calculated using 0.75 kW/hp as a conversion factor. 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).[12] The usage rate, in hours per year (hrs/yr), for these 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. Table XVI-11 presents unit energy and fuel requirements for the four gas flotation units evaluated.

TABLE XVI-11

FUEL REQUIREMENTS FOR GAS FLOTATION UNITS[23]

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

The energy requirements for these four units were used to predict the energy requirements for the nine design systems described in Section XI. In addition, the total design system power requirements include the power required to operate the feed pumps. Natural gas fuel requirements were only calculated for those design systems that treat more than 5,000 bpd of produced water, or require more than 25 hp total to operate. For those design systems that require less than 25 hp to operate, it was assumed that existing onsite power generation equipment can handle an additional load of no more than 25 hp, at no additional cost. A natural gas driven generator will supply the energy required to operate systems that

treat more than 5,000 bpd of produced water. The power and fuel requirements for the complete gas flotation systems designed to treat from 200 to 80,000 bpd of produced water are presented in Table XVI-12.

TABLE XVI-12

FUEL REQUIREMENTS FOR DESIGN GAS FLOTATION SYSTEMS FOR EXISTING SOURCES

Feed Rate (bpd)	200	1,000	2,000	5,000	10,000	15,000	25,000	40,000	80,000
Power Required (hp)	12.2	13.4	15.3	22.8	36	49	75	115	218
Electricity Required (kW)	9.1	10.0	11.5	17.1	0	0	0	0	0
Fuel Required (MMscf/yr)	0	0	0	0	3.0	4.1	6.2	9.6	18.1

In order to predict the energy requirements and fuel usage for treatment systems with flows greater than 5,000 bpd and other than the design flows shown in Table XVI-12, a linear mathematical model was developed through a regression analysis, of the form:

$$HP = 9.77 + 0.0026 \times (\text{flow})$$

Energy requirements for each facility with flows greater than 5,000 bpd were calculated using the linear model based on the produced water flow of each facility. Table XVI-13 summarizes the power utilization (hp-hr/yr) and fuel requirements for all BAT and NSPS options for produced water discharges. Appendices XVI-2 and XVI-3 present the detailed calculations for the BAT and NSPS non-water quality impacts, respectively.

3.1.1.2.2 Injection

Energy requirements for the injection systems were estimated based on produced water being pretreated by cartridge filtration at medium/large-volume facilities with water access, and then injected into a well with a capacity of 5,000 bpd at an injection pressure of 1500 psig. At medium/large-volume facilities with land access, energy requirements represent the horsepower requirements to operate the injection pumps without filtration. The following assumptions were made in calculating the energy requirements for reinjection:

TABLE XVI-13
POWER UTILIZATION AND FUEL REQUIREMENTS
FOR PRODUCED WATER TREATMENT OPTIONS
(from Appendix XVII-2)

Option	BAT[a]				NSPS[b]			
	Power Usage (hp-hr/yr)	Diesel (gal/yr)	Natural Gas (Mscf/yr)	Total Fuel (BOE/yr)[c]	Power Usage (hp-hr/yr)	Diesel (gal/yr)	Natural Gas (Mscf/yr)	Total Fuel (BOE/yr)[c]
Gulf of Mexico								
Gas Flotation	9,924,247	436,070	94,280	27,165	716,568	21,032	6,807	1,712
Zero Discharge	147,282,513	415,430	1,399,184	249,055	3,221,790	21,032	30,607	5,948
Cook Inlet								
Gas Flotation	845,866	0	8,036	1,430	0	0	0	0
Zero Discharge	50,155,906	0	476,481	84,814	0	0	0	0

[a] From Appendix XVII-2
[b] From Appendix XVII-3
[c] BOE (barrels of oil equivalent) per year is the sum of total diesel volume in barrels and total natural gas volume converted to equivalent oil volume by the factor: 1,000 scf = 0.178.

- There will be one operating natural gas driven injection pump (reciprocating internal combustion engines) per every 5,000 barrels of produced water per day. According to one operator, reciprocating internal combustion engines are more prevalent in the Gulf of Mexico operations than gas turbine engines.[27] According to the same source, gas turbine engines may be more applicable to offshore platforms such as Cook Inlet, where weight and space requirements make them more desirable.

- The filtration feed pumps will be run by electricity for up to 25 hp requirements. The electric power will be supplied by existing power generation equipment at each facility. For larger systems that require more than 25 hp to operate, natural gas driven feed pumps are included.

Energy requirements for commercially available injection and feed pumps were obtained from equipment vendors for three different size pumps ranging in capacity from 200 to 5,000 bpd. 1994).[25] For systems with flows greater than 5,000 bpd, multiple integer units were included, based on capacity intervals of 5,000 bpd. Table XVI-14 presents unit energy and fuel requirements for all the design systems with both water- and land access. The power required represents the total system power requirements. Electricity requirements shown represent only the power requirements up to 25 hp. The

TABLE XVI-14
ENERGY REQUIREMENTS FOR DESIGN INJECTION SYSTEMS
FOR EXISTING SOURCES IN THE GULF OF MEXICO
(from Appendix XVII-2)

	Design Flow (bpd)							
	200	500	1,000	5,000	10,000	18,000	30,000	42,000
Facilities With Water Access								
Power Required (hp)	9	19	41	176	352	704	1,068	1,614
Electricity Required (kW)	6.8	14.3	1.5	4.5	9	18	18	18
Fuel Required (MMscf/yr)	0	0	3.25	14.1	28.3	56.6	86.9	132.3
Facilities With Land Access								
Power Required (hp)	8	18	39	170	340	680	1,020	1,530
Electricity Required (kW)	6	13.5	0	0	0	0	0	0
Fuel Required (MMscf/yr)	0	0	3.25	14.1	28.3	56.6	84.9	127.3

natural gas fuel requirements shown represent energy requirements above 25 hp.

In order to predict the energy requirements and fuel usage for treatment systems that require more than 25 hp to operate (or facilities with water access and with flows greater than or equal to 700 bpd, and facilities with land access and flows greater than 727 bpd) other than the design flows, two linear mathematical models were developed through a regression analysis, of the form:

$$HP = 0.0372 \times (\text{flow}) - 11.22 \qquad \text{(water access)}$$

$$HP = 0.0359 \times (\text{flow}) - 3.10 \qquad \text{(land access)}$$

Energy requirements for each facility with flows greater than 700 bpd and 727 bpd for water- and land-access, respectively, were calculated using the linear models based on each facility location and the produced water flow. Table XVI-13 summarizes the power usage (hp-hr/yr) and fuel requirements for all BAT and NSPS options considered for produced water discharges in the coastal region.

3.1.1.3 Cook Inlet

For the eight discharging facilities, energy requirements and air emissions were estimated for equipment that is required in addition to existing equipment to meet the limitations of the three regulatory

options considered to control discharges of produced water. The equipment required to comply with the control options for produced water in Cook Inlet is presented in Section XI. Table XVI-13 summarizes the power and fuel requirements to comply with the treatment options for the control of produced water discharges in Cook Inlet. Detailed calculations of the totals presented in Table XVI-13 are provided Appendix XVI-2.

3.1.2 Air Emissions

The air emissions were calculated for each discharging facility by taking the product of 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 emission factors for both natural gas-fired reciprocating engines and turbines.[26] Table XVI-5 presents the emission factors used in calculating air emissions for all treatment technologies considered to control produced water discharges in the coastal Gulf of Mexico area. Air emissions for medium/large volume facilities in the Gulf of Mexico were estimated from emission factors for reciprocating engines. According to industry sources, almost all engines used at tank batteries and compressor stations are reciprocating internal combustion engines.[27] Air emissions for discharging facilities in Cook Inlet were estimated from emission factors for natural gas driven turbines.[1] Table XVI-15 summarizes the air emissions for all options for both the Gulf of Mexico and Cook Inlet regions. Detailed calculations of the totals in Table XVI-15 are provided in Appendix XVI-2.

In order to determine the significance of the air emission estimates, EPA investigated the amount of air emissions associated with subsurface injection compared to the total air emissions generated by a typical production operation prior to the installation of an injection system. EPA obtained air emission estimates from an air permit application for an average size oil and gas production tank battery and a gas compressor station in Louisiana.[28,29] As described below, these data indicated that the increase in total air emissions due to injection would be 13.3 percent above the current level ((22 x 100)/(188 - 22)=13.3%).

The tank battery permit application included air emission data for a planned produced water injection system using two natural gas powered 175 hp engines to drive the injection pumps. Although the estimates also include hydrocarbon emissions from a 1,500 bbl saltwater storage tank, the predominant source was the gas powered engines. Sources of air emissions at the tank battery include an oil pipeline pump engine, heater treater, oil storage tanks, a produced water settling tank, sump tanks,

TABLE XVI-15

AIR EMISSIONS FOR PRODUCED WATER TREATMENT OPTIONS (tons/year)

Options	BAT				NSPS		
	Gulf of Mexico		Cook Inlet	Total	Gulf of Mexico		
	Small-Vol	Med./ Large-Vol.			Small-Vol.	Med./ Large-Vol.	Total
Option 1: BPT All	0	0	0	0	0	0	0
Option 2: Flotation All	73.10	183.62	1.683	258.4	4.051	13.259	17.31
Option 3: Zero Discharge; Cook Inlet BPT	74.03	2,725.29	0	2,799.3	4.051	59.617	63.67
Option 4: Zero Discharge; Cook Inlet Flotation	74.03	2,725.29	1.683	2,801.0	4.051	59.617	63.67
Option 5: Zero Discharge All	74.03	2,725.29	99.815	2,899.1	4.051	59.617	63.67

fugitive emissions and flash gas emissions. The air emissions included in this analysis are from NOx, THC, SO_2, CO, and TSP. Total emissions from the tank battery were estimated to be 188 tons/yr. Of the total emissions, the estimated portion of the air emission associated with produced water subsurface injection was only 22 tons per year. The total emissions from the tank battery including the injection system, but not including the compressor station, was 102.7 tons per year. The total emissions from the compressor station was estimated to be 85.3 tons per year. Tables showing the individual air pollutant emission values are presented in Appendix XVI-4.

The tank battery is considered an average facility because it produces 2,500 bpd of produced water which is close to the average produced water volume of 2,265 bpd for the discharging facilities in the Gulf of Mexico region (see Section VIII). The tank battery also produced 340 bpd of oil and 1.5 MMcfd of natural gas.

It is common practice for a compressor station to process gas from several tank batteries. In order to include associated air emissions from a compressor station, EPA obtained air emission data from a 15 MMcfd compressor station also located in Louisiana. The air emission estimates for that station were multiplied by a factor of 0.1 (1.5 MMcfd/15 MMcfd) so that only the portion of the compressor

station air emission associated with the tank battery were included. These compressor station air emission values were then added to the tank battery emission values to obtain the overall emissions from this production operation which was estimated to be 188 tons per year. The 13.3 percent increase is probably an overestimate for the following reasons:

- The tank battery produces only 1.5 MMcfd compared to the average gas production value of 2.65 MMcfd reported for produced water dischargers in the 1993 Coastal Survey. Replacing the volume of 1.5 MMcfd with 2.9 MMcfd as the baseline production volume results in percent increase in emissions due to injection of 9.5 percent rather than 13.3 percent.

- The baseline estimate does not include emissions generated as the result of applying artificial lift used to extract hydrocarbons in oil fields with depleted natural drive. The most common artificial lift methods are sucker rod pumping and gas lift using gas compressors.

- Other minor ancillary emission sources (e.g., operator transportation) were not included in the baseline analysis.

3.2 OTHER FACTORS

3.2.1 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 EPA estimates regarding transport boat usage. The service vessel usage at coastal facilities may be as high as two supply boats per day and two crew boats per day during the exploration and development operations. In general, service vessels make three trips per week to exploration and development operations and one trip per week to production facilities. A boat may visit only one site or, if it is only going to production facilities, it may visit as many as five facilities 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 coastal production facilities and drilling 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.[23]

MMS data show that for offshore operations alone, there were 25,000 service vessel trips to support oil and gas related activities in Federal waters of the Gulf of Mexico in 1988.[30] These data do not include vessel traffic destined for coastal or offshore activities in the State territorial seas and therefore under-count actual boat traffic. In estimating the vessel traffic resulting from this rule, EPA projected that transporting produced water from wells subject to zero discharge would require a total of 114 barge trips per year (51 in Louisiana and 63 in Texas) (see Sections 3.1.1.1.1 and 3.1.1.1.2). In comparison to the offshore MMS data alone, it is apparent that the differential increase in boat traffic due to this rule would be less than one percent of all service vessel traffic.[30]

Since service vessels must have unimpeded access to supply bases to continue servicing coastal activities, maintenance dredging of navigation channels would be required regardless of whether this rule was promulgated. 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 one percent, any increase in vessel traffic due to this rule is expected to be minimal. No significant increase in dredging activities is anticipated as a result of this rule.

3.3 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 holes in injection tubing, casing and cement. To prevent ground water contamination, 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 with permitted Class II injection wells 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.

As a result of a 5-year study of the effectiveness of the 1980 UIC regulations concerning the construction, operation, and closure of Class II injection wells, EPA concluded that more detailed minimum national standards than those promulgated in 1980 are necessary to prevent endangerment of underground sources of drinking water (USDW).

EPA is currently in the process of developing such national standards that would establish:

- a minimum national standard for well construction,
- more frequent mechanical integrity testing when the construction of a well does not meet that minimum standard, and
- a requirement for Area of Review studies for wells located in areas where USDWs are subject to significant risk of indirect flow via improperly constructed or abandoned wells.

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 resulting from transportation to commercial disposal. No incremental energy impact an air emission would result from Option 1. No incremental energy requirements and air emissions have been estimated for existing and new source facilities that treat and discharge or inject TWC fluids onsite because the control options for the facilities that treat and inject onsite are based on commingling TWC fluids with the produced water. Table XVI-16 summarizes the energy requirements and air emissions for Option 2a and 2b for workover/treatment fluids and for completion fluids. The values presented in Table XVI-16 are the same for both Options 2a (zero discharge option) and 2b (gas flotation option). The detailed calculations for these results are provided in Appendix XVI-5.

The following sections present the assumptions and the methodology used to estimate energy requirements and air emissions from transportation and handling activities associated only with commercial disposal of TWC fluids.

4.1 ENERGY REQUIREMENTS

The fuel usage due to operation of barges and trucks to transport TWC fluids from either water- or land-accessed facilities to commercial facilities for disposal were calculated by estimating the fuel consumption required by trucks and tugs to pull the barges, the distance barges and trucks have to travel, by auxiliary generators when the barges are loaded and tugs are idling, and by vacuum pumps and compressors to unload the barges. In addition to the assumptions presented for produced water commercial disposal in Sections 3.1.1.1.1 and 3.1.1.1.2, the following assumptions were used:

- Barge capacity to transport TWC fluids from water-accessed facilities to commercial disposal is 1,500 bbl (Section XII).

TABLE XVI-16
NON-WATER QUALITY IMPACTS FOR TWC FLUIDS - BAT AND NSPS OPTIONS**
(from Appendix XVII-5)

Stream	Fuel Requirements (BOE/year)*		Air Emissions (tons/year)	
	BAT	NSPS	BAT	NSPS
Workover/Treatment Fluids	616	82	6.409	0.851
Completion Fluids	522	73	5.792	0.813
Total	1,138	155	12.201	1.66

* BOE (barrels of oil equivalent) per year is the total diesel volume converted to equivalent oil volume by the factor: 1 BOE = 42 gal.

** These impacts are for options 2a and 2b: No impacts result from Option 1.

- Number of barge trips to transport treatment/workover fluids and completion fluids from water-accessed facilities are based on the number of jobs per year. (see Appendix XVI-5).
- Number of truck-trips to transport TWC fluids from land-accessed facilities were estimated based on the volume of TWC fluids per job, the number of jobs per year, and a truck capacity of 119 bbl (see Appendix XVI-5).
- Average truck distance between a land-accessed facility and the barge transfer station is 120 miles (see Section 3.1.1.1.2).
- Total annual volume of treatment/workover and completion fluids requiring commercial disposal was estimated based on the volume generated per job of 587 bbl/job and 209 bbl/job, respectively, and on the number of jobs per year.[31]

Tables XVI-17 and XVI-18 present the energy required to transport TWC fluids to commercial facilities for disposal, under the BAT and NSPS profiles, respectively.

4.2 AIR EMISSIONS

The air emissions were calculated for each stream by taking the product of specific emission factors, the usage in hours, and the fuel requirements. Table XVI-5 presents the emission factors for barges, trucks and auxiliary equipment used in calculating air emissions for both streams. Table XVI-16

TABLE XVI-17

NON-WATER QUALITY IMPACTS FOR TWC FLUIDS FOR BAT BY FACILITY TYPE

Facility Type	Volume TWC Fluids (bbl/yr)	Fuel Requirements (gal/yr)				Air Emissions (tons/yr)
		Barge	Truck	Auxiliary Equipment	Total	
Workover/Treatment Fluids						
Water-Access	31,111	21,200	0	546	21,746	5.996
Land-Access	16,436	0	4,144	0	4,144	0.413
Completion Fluids						
Water-Access	10,450	20,000	0	515	20,515	5.656
Land-Access	5,434	0	1,371	0	1,371	0.136

TABLE XVI-18

NON-WATER QUALITY IMPACTS FOR TWC FLUIDS FOR NSPS BY FACILITY TYPE

Facility Type	Volume TWC Fluids (bbl/yr)	Fuel Requirements (gal/yr)				Air Emissions (tons/yr)
		Barge	Truck	Auxiliary Equipment	Total	
Workover/Treatment Fluids						
Water-access	4,109	2,800	0	72	2,872	0.792
Land-access	2,348	0	592	0	592	0.059
Completion Fluids						
Water-access	1,463	2,800	0	72	2,872	0.792
Land-access	836	0	211	0	211	0.021

also summarizes the air emissions resulting from the transportation of TWC fluids to commercial facilities for disposal. The air emissions evaluated for the TWC fluids options are the same as those identified for the produced water treatment options: nitrogen oxides (NO_x), total hydrocarbons (THC), sulfur dioxide (SO_2), carbon monoxide (CO), and total suspended particulates (TSP).

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SECTION XVII

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 proposed rule for the coastal subcategory of the oil and gas extraction point source category does not establish "best management practices" (BMPs). EPA believes that current industry practices, in conjunction with the requirements currently in the proposed stormwater rule (58 FR 61262-61268), November 19, 1993), would be sufficient to minimize the introduction of contaminants to this wastestream to the extent possible. Although BMPs were not developed for this rule, EPA identified several general areas where BMPs may be applicable. The following paragraphs describe some examples of BMPs that could be established and be effective through the issuance of NPDES permits.

In the coastal 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. As noted in the stormwater proposal, the two types of BMPs most effective in reducing stormwater are to minimize exposure (e.g., covering, curbing, or diking) and treatment type BMPs which are used to reduce or remove pollutants in stormwater discharges. Another minimization technique is keeping leaks and deck drainage segregated from other wastes or "clean" stormwater. The potential for contamination of deck drainage is related to the degree to which segregation is practiced. "Clean" deck drainage should be segregated from sources of contamination. Many sources exist at coastal facilities where leaks or spills could occur. The areas should be managed so that all leaks and/or spills are contained and not discharged to surface waters.

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 coastal facility operation are:

1. Separation of used motor oil 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. Segregation of deck drainage from oil leaks from pump bearings and seals by directing the leakage 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 contaminated drilling fluid. Once segregated, the contaminated drilling fluid can be disposed of in an environmentally acceptable manner.

6. Substitution of standard drill pipe threading compound (pipe dope) with "toxic metals free" pipe dope. Standard pipe dope can contribute high amounts of lead and other metals to discharged drilling fluids and cuttings.

7. Careful application of standard drill pipe dope to minimize contamination of receiving water and drilling fluids.

8. Substitution of diesel oil with less toxic mineral oil or synthetic oil in drilling fluid applications.

9. Substitution of standard drilling fluid additives with less toxic additives.

10. Segregation of contaminated process area deck drainage and runoff from relatively uncontaminated runoff from areas such as parking areas, office space, walkways, and living quarters.

11. Segregated handling, storage and disposal of contaminated drilling waste from less contaminated waste.

12. Installation of roofs and sheds to divert uncontaminated rainfall from areas with a high potential for generating contaminated runoff.

13. Segregation of existing roof drains from contaminated deck drainage sources.

14. Careful handling of drilling fluid materials and treatment chemicals to prevent spills.

15. Use of local containment devices such as liners, dikes and drip pans where chemicals are being unpackaged and where wastes are being stored and transferred.

16. Install treatment devices for deck drainage to reduce or remove pollutants in the discharges (e.g., skim tanks, oil/water separators, sediment tanks/basins, or detention ponds).

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.

GLOSSARY AND ABBREVIATIONS

Acidizing/fracturing fluids: Fluids used to induce formation fracturing, which is a method of stimulating production by opening new flow channels in the rock surrounding a production well. Often called a frac job. Under extremely high hydraulic pressure, a fluid (such as distillate, diesel fuel, crude oil, dilute hydrochloric acid, water, or kerosene) is pumped downward through production tubing or drill pipe and forced out below a packer or between two packers. The pressure causes cracks to open in the formation, and the fluid penetrates the formation through the cracks. Sand grains, aluminum pellets, walnut shells, or similar materials (propping agents) are carried in suspension by the fluid into the cracks. When the pressure is released at the surface, the fracturing fluid returns to the well. The cracks partially close on the pellets, leaving channels for oil to flow around them to the well.

Act: The Clean Water Act.

Adjacent wetlands: Wetlands adjacent to bodies of water. They may be either salt, brackish, or freshwater wetlands. Adjacent here means bordering, contiguous, or neighboring (wetlands separated from other waters of the United States by manmade dikes or barriers, natural river barriers, beach dunes, and the like are adjacent wetlands).

Agency: U.S. Environmental Protection Agency.

Air/Gas Lift: Lifting of liquids by injection of air or gas directly into the well.

Annular Injection: Injection of fluids into the space between the drill string or production tubing and the open hole or well casing.

Annulus or Annular Space: The space between the drill string or casing and the wall of the hole or casing.

AOGA: Alaskan Oil and Gas Association.

API: American Petroleum Institute.

Barite: Barium sulfate. An additive used to increase drilling fluid density.

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 fluid.

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.

BOE: Barrels of oil equivalent. Used to put oil production and gas production on a comparable volume basis.

Bottom-Hole Pressure: Pressure at the bottom of a well.

BPD: Barrels per day.

BPT: The best practicable control technology currently available, under section 304(b)(1) of the Act.

BPY: Barrels per year.

Brackish Water: Water containing low concentrations of any soluble salts.

Brine: Water saturated with or containing high concentrations of salts including sodium chloride, 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 and cemented, drilling continues through and below the casing with a smaller bit. The overall length of this casing is called the casing string. More than one string inside the other may be used in drilling the same well.

Cement: A cement slurry is used to seal the space between well casing and the wall of the hole and between two overlapping casing strings.

Centrifuge: Filtration equipment that uses centrifugal force to separate substances of varying densities. A centrifuge is capable of spinning substances at high speeds to obtain high centrifugal forces. Also called the shake-out or grind-out machine.

Chapman Line: The Chapman line defines the landward boundary of the coastal definition as defined in the July 21, 1982, *Federal Register*. The term "coastal" shall mean all land and water areas landward from the inner boundary of the territorial sea as defined in 40 CFR 125.1 (gg) and bounded on the inland side by the line defined by the inner boundary of the territorial seas as defined above eastward of the point defined by 89°49' W. Longitude and 29°46' N Latitude and continuing as follows west of the point:

Direction to West Longitude	**Direction to North Latitude**
West, 89°48'	North, 29°52'
West, 90°12'	North, 30°06'
West, 90°20'	South, 29°35'
West, 90°35'	South, 29°30'
West, 90°43'	South, 29°25'
West, 90°57'	South, 29°32'

Direction to West Longitude	Direction to North Latitude
West, 91°02'	South, 29°40'
West, 91°14'	South, 29°32'
West, 91°27'	South, 29°37'
West, 91°33'	South, 29°46'
West, 91°46'	South, 29°50'
West, 91°50'	South, 29°55'
West, 91°56'	South, 29°50'
West, 92°10'	South, 29°44'
West, 92°55'	South, 29°46'
West, 93°15'	South, 30°14'
West, 93°49'	South, 30°07'
West, 94°03'	South, 30°08'
West, 94°10'	South, 30°00'
West, 95°20'	South, 29°53'
West, 95°00'	South, 29°35'
West, 95°13'	South, 29°28'
West, 95°08'	South, 29°15'
West, 95°11'	South, 29°08'
West, 95°22'	South, 28°56'
West, 95°30'	South, 28°55'
West, 95°33'	South, 28°49'
West, 95°40'	South, 28°47'
West, 96°42'	South, 28°41'
West, 96°40'	South, 28°28'
West, 96°54'	South, 28°20'
West, 97°03'	South, 28°13'
West, 97°15'	South, 27°58'
West, 97°40'	South, 27°45'
West, 97°46'	South, 27°28'
West, 97°51'	South, 27°22'
West, 97°46'	South, 27°14'
West, 97°30'	South, 26°30'
West, 97°26'	South, 26°11'

Chemical Treatment Fluids: Any fluid used to restore or improve productivity by chemically or physically altering hydrocarbon-bearing strata after a well has been drilled. Well treatment fluids include substances such as acids, solvents, and propping agents. (See acidizing/fracturing fluids).

Christmas Tree: Assembly of fittings and valves at the top of the casing of an oil/gas well that controls the flow of oil/gas 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).

Coastal Region: Any body of water landward of the inner boundary of the territorial seas or any wetlands adjacent to such waters.

Completion: Activities undertaken to finish work on a well and bring it to productive status.

Completion Fluids: Low-solids fluids or drilling muds used when a well is being completed. They are selected not only for their ability to control formation pressure, but also for the properties that minimize formation damage.

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.

Condensate: Liquid hydrocarbons which are in the gaseous state under reservoir conditions but which become liquid either in passage up the hole or in the surface equipment.

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.

Cumulative Distribution: A cumulative distribution describes the percentage of observations in a data set that are less than or equal to pre-specified values. For example, in terms of toxicity measurements, the cumulative distribution displays the percentage of toxicity measurements less than or equal to each specified toxicity value.

Deck Drainage: All wastes resulting from platform washings, deck washings, spills, rainwater, and runoff from curbs, gutters, and drains, including drip pans and wash areas.

Degassers: Devices used to remove gas from a liquid, especially from drilling fluid.

Depth Interval: Interval at which a drilling fluid system is introduced and used, such as from 2,200 to 2,800 ft.

Desanders: A device used to remove sand from drilling fluid to prevent abrasion of the pumps and piping. It may be operated mechanically or by a fast-moving stream of fluid inside a special, cone-shaped vessel, in which case it is called a hydroclone.

Desilters: A device used to remove silt from drilling fluid. It may be operated mechanically or by a fast-moving stream of fluid inside a special, cone-shaped vessel, in which case it called a hydroclone.

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.

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.

Drill Pipe: Special pipe designed to withstand the torsion and tension loads encountered in drilling.

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 fluid 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.

Drilling Fluid System: System consisting primarily of mud storage tanks or pits, mud pumps, stand pipe, kelly hose, kelly, drill string, well annulus, mud return flowline, and solids separation equipment. The primary function of circulating the drilling fluid is to lubricate the drill bit, and to carry drill cuttings rock fragments from the bottom of the hole to the surface where they are separated out.

Emulsion: A stable 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 the presence of small amounts of substances known as emulsifiers. Emulsions may be oil-in-water, or water-in-oil.

Estuarine Wetlands: General term applied to coastal wetlands (tidal marshes), mangrove swamps and intertidal flats where salinity is greater than 0.5 ppt (see Salt or Brackish Wetlands).

Exploratory Well: A well drilled either in search of an as-yet-undiscovered pool of oil or gas (a wildcat well) or to extend greatly the limits of a known pool. It involves a relatively high degree of risk. Exploratory wells may be classified as (1) wildcat, drilled in an unproven area; (2) field extension or step-out, drilled in an unproven area to extend the proved limits of a field; or (3) deep test, drilled within a field area but to unproven deeper zones.

Facility: See Produced Water Separation/Treatment Facility.

Field: A geographical area in which a number of oil or gas wells produce hydrocarbons from an underground reservoir. A field may refer to surface area only or to underground productive formations as well. A single field may have several separate reservoirs at varying depths.

Filter Backwash: Wastewater generated when filters are cleaned and maintained.

Filter Sludge: Solids removed via filtration.

Filtration: The process of removing the solids from a fluid. Filtration can be used on both produced water or workover/completion fluids.

Flocculation: The combination or aggregation of suspended solid particles in such a way that they form small clumps or tufts resembling wool.

Flotation: Process by which water that is slightly oil contaminated is circulated to be cleaned before it is disposed. Since oil droplets cling to rapidly rising gas, a device such as a bubble tower is usually installed in the flotation cell to permit the introduction of gas into the water.

Fluid Injection: Injection of gases or liquids into a reservoir to force oil toward and into producing wells. (see also "Water Flooding" and "Pressure Maintenance.")

Footprint: The square footage covered by various production equipment.

Formation: Various subsurface geological strata.

Formation Damage: Damage to the productivity of a well resulting from invasion of drilling fluid particles or other substances into the formation.

Fracturing: A method of stimulating production by opening new flow channels in the rock surrounding a production well. Often called a frac job. See Acidizing/fracturing fluids.

Free Water Knockout (FWKO): A vertical or horizontal vessel into which oil or emulsion is run to allow any water not emulsified with the oil (free water) to drop out.

Freshwater Wetlands: Wetlands in which salinity is 0.5 ppt or less, and including marshes, swamps, bogs, and other such areas.

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.

Injection Well: A well through which fluids are injected into an underground stratum to increase reservoir pressure and to displace oil, or for disposal of produced water and other wastes.

Inland Bay/Harbor: A bay or harbor landward of the inner boundary of the territorial sea.

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.

Isolated Wetlands: Wetlands that are not adjacent to a body of surface water.

Joint Cumulative Distribution: A joint cumulative distribution describes the total amount of one measured factor associated with specified amounts of a second measured factor. For example, the joint cumulative distribution of the volume of discharged drilling fluids in relation to toxicity measurements displays the total drilling fluids in relation to toxicity measurements displays the total volume of discharged drilling fluids associated with each toxicity level.

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.

Lease: A legal document executed between a landowner, as lessor, and a company or individual as lessee, that grants the right to exploit the premises for minerals; the instrument that creates a leasehold or working interest in minerals.

Marine Wetland: Intertidal areas of a marine system including: beaches, rocky shores, and some coral reefs where salinity exceeds 30 ppt (see Salt or Brackish Wetlands).

Marginal Oil Well: For the purposes of this regulation: wells producing 10 barrels per calendar day or less of crude oil and that are operating at the maximum feasible rate of production.

Marginal Gas Well: For the purposes of this regulation: wells producing nonassociated natural gas at its maximum efficient rate of flow and at a rate not exceeding an average of 60 thousand cubic feet (Mcf) per production day.

MScf: Thousand standard cubic feet.

Microclone: A device used to separate particles of various sizes from a drilling fluid. The fluid is pumped tangentially into a case and the fluid rotation provides enough centrifugal force to separate particles by mass weight. (See Desander).

Miscellaneous Waste: Workover/treatment fluids; produced sand; and deck drainage.

Mud: Common term for drilling fluid.

Mud Cleaner: Hydroclones mounted above a screen for enhanced solids removal.

Mud Pit: A steel or earthen tank which is part of the surface drilling fluid system.

Mud Pump: A reciprocating, high pressure pump used for circulating drilling fluid.

Multiple Completion: A well completion which provides for simultaneous production from separate zones.

Multiwell Island: Manmade island used in water to support the operation of more than one well.

Multiwell Platform: Platform located in water to support the operation of more than one well.

NPDES Permit: A National Pollutant Discharge Elimination System permit issued under Section 402 of the Act.

NSPS: New source performance standards under Section 306 of the Act.

Oil/Water Separation Facilities: See produced water separation/treatment facilities.

Oil-based Mud: A drilling fluid in which oil is the continuous phase and which contains from less than 2 percent to up to 5 percent water.

Oil-based Pill: Mineral or diesel oil injected into the mud circulation system as a slug, for the purpose of freeing stuck pipe.

Onshore: All land areas landward of the inner boundary of the territorial seas as defined in 40 CFR 125.1 (gg) that are not wetlands adjacent to surface water bodies.

Operator: The person or company responsible for operating, maintaining, and repairing oil and gas production equipment in a field; the operator is also responsible for maintaining accurate records of the amount of oil or gas sold, and for reporting production information to state authorities.

Packer Fluid: A liquid, usually salt water or oil, but sometimes mud, used in a well when a packer is between the tubing and the casing. Packer fluid must be heavy enough to shut off the pressure of the formation being produced, must not stiffen or settle out of suspension over long periods of time, and must be noncorrosive.

Pressure Maintenance: The injection of water or gas into an oil or gas producing formation to maintain the desired formation pressure.

Priority Pollutants: The toxic pollutants listed in 40 CFR Part 423, Appendix A.

Produced Sand: Slurried particles used in hydraulic fracturing and the accumulated formation sands and other particles that can be 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.

Produced Water: Water (brine) brought up from the hydrocarbon-bearing strata with the produced oil and gas. This includes brines trapped with the oil and gas in the formation, injection water, and any chemicals added downhole or during the oil/water separation process.

Produced Water Separation/Treatment Facilities: A "facility" is any group of tanks, pits, or other apparatus that can be distinguished by location, e.g., onsite/offsite or wetland/upland and/or by disposal stream (any produced water stream that is not recombined with other produced water streams for further treatment or disposal, but is further treated and/or disposed of separately). The facility may thus be, for example, an onsite tank battery, an offsite gathering center, or a commercial disposal operation. The primary focus is on treatment produced water, not on treating oil.

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.

RCRA: Resource Conservation and Recovery Act (Pub. L. 94-580) of 1976. Amendments to Solid Waste Disposal Act.

Recompletion: When additional drilling occurs at an existing well after the initial completion of the well and drilling waste is generated.

Reserve Pit: A waste pit, usually an excavated earthen-walled pit. It may be lined with plastic or other material to prevent soil contamination.

Reserve Pit Liquids: The liquids surfacing to the top of reserve pits after settling of solids; can also include rain water, rig wash water, etc.

Reservoir: Each separate, unconnected body of a 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.

Salt or Brackish Wetlands: Marine or estuarine wetlands (see definitions above), where salinity is greater than 0.5 ppt.

Saltwater Drilling Fluid: Drilling fluids whose major fluid component of continuous phase is saltwater.

Sanitary Waste: Human body waste discharged from toilets and urinals located with in facilities addressed by this document.

Secondary Recovery: The use of waterflooding or gas injection to maintain formation pressure during primary production and to reduce the rate of decline of the original reservoir drive.

2-Phase Separator: A vessel used to separate oil/water and gas by gravity.

3-Phase Separator: A vessel used to separate oil, water 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.

Settling or Skim Pit or Tank: A pit or tank into which produced emulsion is piped and in which water in the emulsion is allowed to settle out of the oil. Oil can be skimmed off the top.

Shale Shaker: A vibrating screen used to remove cuttings from the circulating fluid in rotary drilling operations. The size of the openings in the screen should be carefully selected to be the smallest size possible to allow 100 percent flow of the fluid. Also called a shaker.

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: A large diameter pipe attached to the platform extending below the surface of the water used to separate oil from produced water as a final treatment step before discharge.

Spot: The introduction of oil to a drilling fluid system for the purpose of freeing a stuck drill bit or string.

Spud Date: Date drilling of the well began.

State Discharge Permit Number: Permit number assigned by state. Permit allows discharge to water bodies.

Stratified Random Sample: In a stratified random sample, the entire population is first divided into N groups, or strata. Within each strata, an independent random sample of units is selected according to predetermined sample sizes. Estimates from each of the strata then can be combined to form national estimates. Stratified random sampling is recommended when estimates are required for specific subdivisions of the population. It is advantageous to construct the strata such that the units are homogeneous within a stratum and are heterogeneous between strata.

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.

Tank Battery: A group of production tanks located in a field to store crude oil.

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.

Total Measured Depth: The total length of the well bore at the end of the drilling process.

TSS: Total Suspended Solids.

Upland Site: A site not located in a wetland area. May be an onshore site or a coastal site under the Chapman Line definition.

USCG: United States Coast Guard.

USGS: United States Geological Survey.

Water-based Mud: A drilling mud in which the continuous phase is water. In water-base muds, any additives are dispersed in the water.

Water Flooding: Water is injected under pressure into the formation via injection wells to maintain reservoir pressure and to displaced oil toward the producing wells.

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.

Wetlands: Those surface areas which are inundated or saturated by surface or ground water at a frequency and duration sufficient to support, and that under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions. Wetlands generally include swamps, marshes, bogs, and similar areas.

Workover: The performance of one or more of a variety of remedial operations on a producing oilwell to try to increase production. Examples of workover jobs are deepening, plugging back, pulling and resetting liners, and squeeze cementing.

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. A workover fluid is compounded carefully so that it will not cause formation damage.

Appendix VII-1

Drilling Fluid Components and Applications

Drilling Fluid Components and Applications
(Chilingarian and Vorabutr, 1983)

Drilling Fluid Component	Description or Principal Component	Primary Application
Weighting Agents and Viscosifiers	Barite	For increasing mud weight up to 20 ppg.
	Calcium Carbonate	For increasing weight of oil muds up to 10.8 ppg.
	Bentonite	Viscosity and filtration control in water-base muds.
	Sub-Bentonite	For use when larger particle size is desired for viscosity and filtration control.
	Attapulgite	Viscosifier in saltwater muds.
	Beneficiated Bentonite	Quick viscosity in fresh-water, upperhole muds with minimum chemical treatment.
	Asbestos Fibers	Viscosifier for fresh-water or saltwater muds.
	Bacterially Produced Polymer	Viscosifier and fluid-loss control additive for low-solids muds.
	Sepiolite	Viscosifier in all water-based muds, especially high-temperature drilling fluids.
Dispersants	Sodium Tetraphosphate	Thinner for low pH fresh-water muds where temperatures do not exceed 180°.
	Sodium Acid Pyrophosphate	For treating cement contamination.
	Quebracho Compound	Thinner for fresh-water and lime muds.
	Modified Tannin	Thinner for fresh-water and saltwater muds alkalized for pH control.
	Processed Lignite	Dispersant, emulsifier and supplementary additive for fluid-loss control.
	Causticized Lignite	1-6 ratio caustic-lignite dispersant, emulsifier and supplementary fluid-loss additive.
	Modified Lignosulfonate	Dispersant and fluid-loss control additive for water-base muds.
	Blended Lignosulfonate Compound	Blended multi-purpose dispersant, fluid-loss agent and inhibitor for IMCO RD-111 mud systems.
	Chrome-Free Lignosulfonate	Dispersant and fluid-loss control additive for water base muds.
Fluid-Loss Reducers	Organic-Polymer	Controls fluid loss in water-base systems.
	Pregelatinized Starch	Controls fluid loss in saturate salt water, lime and SCR muds.
	Sodium Carboxymethyl Cellulose	For fluid-loss control and barite suspension in water-base muds.
	Sodium Carboxymethyl Cellulose	For fluid-loss control and viscosity building in low-solids muds.
	Polyanionic Cellulosic Polymer	Fluid-loss control additive and viscosifier in salt muds.
	Polyanionic Cellulosic Polymer	Primary fluid-loss additive, secondary viscosifier in water-base muds.
	Sodium Polyacrylate	Fluid-loss control in calcium-free low solids and nondispersed muds.

Drilling Fluid Components and Applications (cont.)
(Chilingarian and Vorabutr, 1983)

Drilling Fluid Component	Description or Principal Component	Primary Application
Lubricants, Detergents, Emulsifiers, Surfactants	Extreme Pressure Lubricant	Used in water-base muds to impart extreme pressure lubricity.
	Processed Hydrocarbons	Used in water-based muds to lower downhole fluid loss and minimize heaving shale.
	Water Dispersible Asphalts	Lubricant and fluid-loss reducer for water-base muds that contain no diesel or crude oil.
	Oil Dispersible Asphalts	Lubricant and fluid-loss reducer for water-base fluids that contain diesel or crude oil.
	Oil Soluble Surfactants	Nonweighted fluid for spotting to free differentially stuck pipe.
	Detergent	Used in water-base muds to aid in dropping sand. Emulsifies oil, reduces torque and minimizes bit-bailing.
	Blend of Anionic Surfactants	Emulsifier for saltwater and freshwater muds.
	An Organic Entity Neutralized with Amines	Supplies the lubricating properties of oils without environmental pollution.
	Blend of Fatty Acids, Sulfonates, and Asphaltic Materials	Invert emulsion that may be weighted to desired density for spotting to free differentially stuck pipe.
Defoamers, Flocculants, Bactericides	Aluminum Stearate	Defoamer for lignosulfonate muds.
	Liquid Surface-Active Agent	Defoamer for all water-base muds.
	Surface-Active Dispersible Liquid Defoamer	All-purpose defoamer.
	Flocculating Agent	Used to drop drilled solids where clear water is desirable for a drilling fluid.
	Blended Solutions	Bactericide used to prevent fermentation.
Lost Circulation Materials	Fibrous Material	Filler as well as matting material.
	Nut Shells: Fine	Most often used to prevent lost circulation.
	Nut Shells: Medium	Used in conjunction with fibers or flakes to regain lost circulation.
	Nut Shells: Coarse	Used where large crevices or fractures are encountered.
	Ground Mica: Fine	Used for prevention of lost circulation.
	Ground Mica: Coarse	Forms a good mat at face of wellbore.
	Cellophane	Used to regain lost circulation.
	Combination of granules, flakes, and fibrous materials of various sizes in one sack.	Used where large crevices or fractures are encountered.

Drilling Fluid Components and Applications (cont.)
(Chilingarian and Vorabutr, 1983)

Drilling Fluid Component	Description or Principal Component	Primary Application
Corrosion Inhibitors	Zinc Compound	For use as a hydrogen sulfide scavenger in water-base and oil-base muds.
	Liquid Corrosion Inhibitor	Prevent stress cracking of drill strings in an H_2S environment.
	A Catalyzed Ammonium Bisulfite	For use as an oxygen scavenger.
	Filming Amine	Corrosion inhibitor.
	Filming Amine	Corrosion inhibitor.
	Organic Polymer	Scale inhibitor.
Specialty Products	Bentonite Extender	Increases yield of bentonite to form very low-solids drilling fluid.
	Inhibiting Agent	Imparts high-temperature fluid-loss control, temperature stability and increased inhibition.
	Synergistic Polymer Blend	Rheological stabilization and filtration control.
	Biodegradable Surfactant	Foaming agent in air or mist drilling.
	High-Temperature Polymer	High-temperature fluid-loss control.
	Multipurpose Polymer	Polymer for fluid-loss control.
Commercial Chemicals	Sodium Chromate	Used in water-base muds to prevent high-temperature gelation.
	Sodium Hydroxide	For pH control in water-base muds.
	Sodium Carbonate	For treating out calcium sulfate in low pH muds.
	Sodium Bicarbonate	For treating out calcium sulfate or cement in high pH muds.
	Barium Carbonate	For treating out calcium sulfate (pH should be above 10 for best results).
	Calcium Sulfate	Source of calcium for formulating gyp muds.
	Calcium Hydroxide	Source of calcium for formulating lime muds.
	Sodium Chloride	For saturated salt muds and resistivity control.
	Chrome Alum (chromic chloride)	For use in cross-linking XC Polymer systems.
Oil-Mud Additives	Primary Emulsifier	Primary additives to form stable water-in-oil emulsion.
	Viscosifier and Gelling Agent	Provides viscosity, weight suspension, and filtration control.
	High-Temperature Stabilizer	Improves emulsion under high-temperature conditions.
	Stabilizes Borehole Conditions	Stabilizes running shale, improves emulsion, weight suspension, and fluid loss under high-temperature conditions.
	Dispersant	Dispersant for reducing rheological properties.
	Calcium Oxide	Calcium source for saponification.
	Fatty Acid Emulsifier	Primary emulsifier and stabilizer for oil-base drilling fluids.

Drilling Fluid Components and Applications (cont.)
(Chilingarian and Vorabutr, 1983)

Drilling Fluid Component	Description or Principal Component	Primary Application
Oil Mud Additives (cont.)	Emulsion Stabilizer	Imparts gels, contributes to viscosity for weight suspension, and provides filtration control.
	Specially Modified Saponified Fatty Acid Chemicals	Gelling agent for formulating high-gelation casing packs.
	Powdered Wetting Agent	Dispersing agent in KEN-X systems with a $CaCl_2$ water internal phase.

APPENDIX X-1

Drilling Waste Compliance Cost

Calculations

Worksheets 1 - 5 and 1T - 5T

Worksheet No. 1, November 7, 1994, Page 1 of 2
Coastal Alaska Oil and Gas Drilling Industry
Zero Discharge Compliance Cost Analysis for Operations in Cook Inlet, Alaska
Cost Estimation for Drilling an Average Injection Well

(1) Operator ID	(2) Well ID	(3) DFS-01 Depth feet	(4) DFS-02 Depth feet	(5) DFS-03 Depth feet	(6) Well Total Depth feet	(7) DFS-01 Drill Time days	(8) DFS-01 Workday hours	(9) DFS-02 Drill Time days	(10) DFS-02 Workday hours	(11) DFS-03 Drill Time days	(12) DFS-03 Workday hours	(13) DFS-01 M & C bbls	(14) DFS-02 M & C bbls	(15) DFS-03 M & C bbls	(16) Total M & C bbls	(17) Average Cuttings % of Total
A	1A	1,389	8,477	2,029	11,895	9	6	21	14	20	11	1,528	9,325	2,232	13,085	NA
A	2A	1,256	8,368	2,176	11,800	3	13	32	12	20	8	1,213	8,081	2,101	11,395	NA
A	3A	1,155	8,642	2,343	12,140	5	9	27	13	47	9	1,361	10,180	2,760	14,300	NA
B	1B	2,110	7,999	860	10,969	23	23	30	23	13	23	3,313	7,334	1,334	11,981	19
B	2B	4,120	5,962	1,478	11,560	NA	NA	30	12	12	12	NA	9,558	1,583	NA	NA
B	3B	4,017	5,745	2,068	11,830	12	12	17	12	12	12	6,065	7,606	2,326	15,997	NA
B	4B	3,823	6,240	2,100	12,163	15	12	20	12	17	12	7,504	8,838	3,024	19,366	NA
AVERAGE		2,553	7,348	1,865	11,765	11	13	25	14	20	12	3,497	8,703	2,194	14,354	19

Operator ID	Well ID	(18) DFS-01 Drill Time hours	(19) DFS-02 Drill Time hours	(20) DFS-03 Drill Time hours	(21) Well Total Drill Time hours	(22) Total Well Drill Cost ($1,000)	(23) Average Drill Rate $/hr	(24) DFS-01 Drill Cost $	(25) DFS-02 Drill Cost $	(26) DFS-03 Drill Cost $	(27) DFS-01 Unit Cost $/ft	(28) DFS-02 Unit Cost $/ft	(29) DFS-03 Unit Cost $/ft	(30) DFS-01 Unit M&C bbls/ft	(31) DFS-02 Unit M&C bbls/ft	(32) DFS-03 Unit M&C bbls/ft
A	1A	54	294	220	568	3,250	5,722	308,979	1,682,218	1,258,803	222	198	620	1.1	1.1	1.1
A	2A	39	384	160	583	3,150	5,403	210,720	2,074,786	864,494	168	248	397	1.0	1.0	1.0
A	3A	45	351	423	819	4,200	5,128	230,769	1,800,000	2,169,231	200	208	926	1.2	1.2	1.2
B	1B	529	690	299	1,518	3,716	2,448	1,294,970	1,689,091	731,939	614	211	851	1.6	0.9	1.6
B	2B	NA	360	144	NA	6,125	NA	NA	NA	NA	NA	NA	NA	NA	1.6	1.1
B	3B	144	204	144	492	4,665	9,482	1,365,366	1,934,268	1,365,366	340	337	660	1.5	1.3	1.1
B	4B	180	240	204	624	5,408	8,667	1,560,000	2,080,000	1,768,000	408	333	842	2.0	1.4	1.4
AVERAGE		165	360	228	767	4,359	6,142	828,467	1,876,727	1,359,639	325	256	716	1.4	1.2	1.2

Average Cost of Drilling a 4000 Foot Injection Well = **$1,197,173**
(Sum of the costs of drilling the first 2,500 feet using the average cost of first drilling fluid system, DFS-01, and the cost of drilling the last 1,500 feet using the average cost of the second drilling fluid system, DFS-02, (2,500 x Column 27) + (1,500 x Column 28))

Average Muds and Cuttings Generated from Drilling a 4000 Foot Injection Well (BBLS) = **5,275**
(Sum of the muds and cuttings (M&C) generated from drilling the first 2,500 feet of well, using the average unit volume M&C of DFS-01, and M&C generated from drilling the last 1,500 feet of the well, using the average unit volume M&C of DFS-02, (2,500 x Column 30) + (1,500 x Column 31))

Average Number of Days for Drilling an Average New Well = **57**
(Sum of the average number of days for each drilled interval)
(Column 7 + Column 9 + Column 11)

Average Number of Days for Recompleting a Well = **20**
(Set equal to the average number of days spent drilling the third drilled interval of new wells, Column 11)

Worksheet No. 1, November 7, 1994, page 2 of 2
Coastal Alaska Oil and Gas Drilling Industry
Zero Discharge Compliance Cost Analysis for Operations in Cook Inlet, Alaska
Cost Estimation for Drilling an Average Injection Well

(1) Operator IDs are confidential, and are therefore discussed in a confidential supporting document (Safavi, Jan. 30, 1995).

(2) Well IDs are confidential, and are therefore discussed in a confidential supporting document (Safavi, Jan. 30, 1995).

(3), (4), and (5) The depth of each drilling fluid system (DFS) was obtained from the 308 questionnaire.

(6) The final depth to which the well was drilled is the sum of all drilled intervals, Column 3 + Column 4 + Column 5.

(7), (8), (9), (10), (11), and (12) Drilling time for each drilling interval was obtained from 308 Questionnaires.

(13), (14), and (15) Muds and Cuttings (M&C) Volumes are as specified in the 308 Questionnaires or calculated from the reported total volume by weighted average based on the depth of each interval.

(16) Total muds and cuttings generated from each well are as reported in the 308 Questionnaires or the sum of muds and cuttings from all drilled intervals.

(17) Average percent of total volume of drilling waste as cuttings was calculated by averaging reported percentages for each drilled interval in the 308 Questionnaires. Only one facility reported cuttings fractions.

(18) Total hours of drilling the first interval is the product of total number of drilling days and average number of drilling hours in a day. Column 7 x Column 8.

(19) Total hours of drilling the second interval is the product of total number of drilling days and average number of drilling hours in a day. Column 9 x Column 10.

(20) Total hours of drilling the third interval is the product of total number of drilling days and average number of drilling hours in a day. Column 11 x Column 12.

(21) Total drilling hours is the sum of total drilling hours for each drilling interval. Column 18 + Column 19 + Column 20.

(22) Total drilling costs were obtained from the 308 Questionnaires.

(23) The average hourly drilling cost for each well is calculated by dividing the total cost of drilling by the number of hours spent to drill the well, Column 22/Column21.

(24) Cost of drilling the first interval is calculated by multiplying the average hourly drilling cost rate for the entire well by the total hours spent drilling the first interval, Column 23 x Column 18.

(25) Cost of drilling the second interval is calculated by multiplying the average hourly drilling cost rate for the entire well by the total hours spent drilling the second interval, Column 23 x Column 19.

(26) Cost of drilling the third interval is calculated by multiplying the average hourly drilling cost rate for the entire well by the total hours spent drilling the third interval, Column 23 x Column 20.

(27) The cost of drilling per unit depth of the first interval is calculated by dividing the total cost of drilling the interval by total depth of the interval, Column24/Column 3.

(28) The cost of drilling per unit depth of the second interval is calculated by dividing the total cost of drilling the interval by total depth of the interval, Column25/Column 4.

(29) The cost of drilling per unit depth of the third interval is calculated by dividing the total cost of drilling the interval by total depth of the interval, Column26/Column 5.

(30) The unit muds and cuttings generated per foot of the first drilled interval is calculated by dividing the total volume of muds and cuttings for the interval by the total depth of the interval, Column 14/Column 3.

(31) The unit muds and cuttings generated per foot of the second drilled interval is calculated by dividing the total volume of muds and cuttings for the interval by the total depth of the interval, Column 15/Column 4.

(32) The unit muds and cuttings generated per foot of the third drilled interval is calculated by dividing the total volume of muds and cuttings for the interval by the total depth of the interval, Column 16/Column 5.

NA Data not available or not applicable.

Note: A 4000-foot injection well is assumed based on information provided by Operator B (Safavi, Jan. 30, 1995).

Worksheet No. 2, November 7, 1994, Page 1 of 2
Coastal Alaska Oil and Gas Drilling Industry
BAT Compliance Cost Analysis for Operators in Cook Inlet, Alaska
Zero Discharge Option by Landfill Disposal (Without Closed–Loop System)

(1) Operator ID	(2) Total # of Platforms	(3) Total # of Platforms With Planned Drilling Program	(4) Total # of New Wells Scheduled 1996–2002	(5) Total # of Recompits Scheduled 1996–2002	(6) Total Incremental Volume of Waste New Wells BBLS	(7) Total Incremental Volume of Waste Recompit Wells BBLS	(8) Total Incremental Volume of Waste All Wells BBLS	(9) Unit Cost of Disposing Drilling Waste $/BBL	(10) Total Disposal Cost New Wells $	(11) Total Disposal Cost Recompits Wells $	(12) Total Disposal Cost All Wells $
A	2	1	3	1	42,631	2,172	44,803	203	8,654,170	440,928	9,095,098
B	12	11	27	18	383,682	39,097	422,780	39	14,963,614	1,524,786	16,488,401
C	1	1	6	0	85,263	0	85,263	203	17,308,340	0	17,308,340
Total	15	13	36	19	511,577	41,269	552,846	NA	40,926,125	1,965,714	42,891,839

Total Disposal Cost of Drilling Wastes for All Operators = **$42,891,839**
(Sum of Disposal Costs for All Operators, Column 12)

Total Disposal Cost Per Barrel of Drilling Waste = **$78**
(Total Disposal Cost/Total Volume of Drilling Wastes, Column 12/Column 8)

Total Disposal Cost of Drilling Wastes Per Platform = **$3,299,372**
(Total Disposal Cost/Total Number of Platforms with Planned Drilling, Column 12/Column 3)

Total Disposal Cost of Drilling Wastes Per Drilling Event = **$779,852**
((Total Disposal Cost)/(Total Number of New and Recompletion Wells), Column 12/(Column 4 + Column 5))

Total Disposal Cost of Drilling Wastes Per New Development Well = **$1,102,501**
(Total Disposal Cost Per Barrel x Volume of Drilling Waste from an Average new Well, (Cost Per Barrel)x(Column 6)/(Column 4))

Total Disposal Cost of Drilling Wastes Per Recompletion Well = **$168,517**
(Total Disposal Cost Per Barrel x Volume of Drilling Waste from an Average Recompletion, (Cost Per Barrel)x(Column 7)/(Column 5))

Worksheet No. 2, November 7, 1994, Page 2 of 2
Coastal Alaska Oil and Gas Drilling Industry
BAT Compliance Cost Analysis for Operators in Cook Inlet, Alaska
Zero Discharge Option by Landfill Disposal (Without Closed–Loop System)

(1) Operator IDs are confidential, and are therefore discussed in a confidential supporting document (Safavi, Jan. 30, 1995).

(2), (3), (4), and (5) Some of the data in these columns are confidential, and are therefore discussed in a confidential supporting document (Safavi, Jan. 30, 1995).

(6) Total Incremental Volume of Drilling Waste from new wells is the product of the Average Volume of drilling waste generated from wells recently drilled in Cook Inlet, the Total Number of Wells scheduled for drilling and Percent of total (99%) drilling waste discharged under current practice. Based on data provided in 1993 Coastal Oil & Gas 308 Survey Questionnaires. See Worksheet No. 1 for details.

(7) Total Incremental Volume of Drilling Waste from recompleted wells is the Product of the Average Volume of drilling waste generated from the third drilled interval of wells recently drilled in Cook Inlet and the total number of wells scheduled for recompletion in Cook Inlet and percent of total (99%) drilling waste discharged under current practice. Based on information provided in 1993 Coastal Oil & Gas Industry Survey Questionnaires. See Worksheet No. 1 for more details.

(8) Total Incremental Volume of Drilling Waste from all wells is the sum of all incremental wastes that will be generated in Cook Inlet, Column 5 + Column 6.

(9) Unit disposal costs for landfill disposal of muds and cuttings generated in Cook Inlet. Data were obtained from 308 Survey Questionnaires or estimated from information provided by Cook Inlet operators. See also the July 25, 1994, SAIC, Worksheet for more details.

(10) Total Disposal Cost for new drilling is the product of Unit Disposal Cost and Total Volume of Drilling Waste from drilling new wells, Column (9) x Column (6).

(11) Total Disposal Cost for recompletions is the product of Unit Disposal Cost and Total Volume of Drilling Waste from Recompleting existing wells, Column (9) x Column (7).

(12) Total Disposal Cost of drilling wastes from all wells or all drilling activities, Column (10) + Column (11).

NA Not applicable.

Worksheet No. 3, November 7, 1994, Page 1 of 2
Coastal Alaska Oil and Gas Drilling Industry
BAT Compliance Cost Analysis for Operators in Cook Inlet, Alaska
Zero Discharge Option by Landfill Disposal (with Closed–Loop System)

(1) Operator ID	(2) Total # of Platforms	(3) Total # of Platforms with Planned Drilling Program	(4) Total # of New Wells Scheduled 1996–2000	(5) Total # of Recompltes Scheduled 1996–2000	(6) Total Incremental Volume of Waste New Wells bbls	(7) Total Incremental Volume of Waste Recompltes Wells bbls	(8) Total Incremental Volume of Waste All Wells bbls	(9) Total # of Days High Efficiency Solid Separation Equipment Needed	(10) Unit Cost of Solid Separation Equipment $/day/unit	(11) Total Cost of High Efficiency Solid Separation $
A	2	1	3	1	29,416	1,499	30,914	191	1,900	362,900
B	12	11	27	18	264,741	26,977	291,718	1,899	1,900	3,608,100
C	1	1	6	0	58,831	0	58,831	342	1,900	649,800
Total	15	13	36	19	352,988	28,476	381,464	2,432	NA	4,620,800

Operator ID	(12) Retrofit Cost of Equipment Per Platform $/platform	(13) Total Cost of Retrofitting Platforms $	(14) Unit Cost of Operating Equipment $/day	(15) Total Cost of Operating Equipment $	(16) Unit Cost of Landfilling Drilling Waste $	(17) Total Cost of Landfilling Drilling Waste $	(18) Total Disposal Cost of Drilling Waste $
A	270,000	270,000	1,000	191,000	203	6,275,618	7,099,518
B	270,000	2,970,000	1,000	1,899,000	39	11,376,996	19,854,096
C	270,000	270,000	1,000	342,000	203	11,942,755	13,204,555
Total	810,000	NA	NA	2,432,000	445	29,595,369	40,158,169

Total Disposal cost of Drilling Waste for All Operators = **$40,158,169**
(Sum of Disposal Costs for All Operators, Column 18)

Total Disposal Cost of Drilling Waste Per Barrel = **$105**
((Total Disposal Cost)/(Total Volume of Drilling Wastes, Column 8))

Total Disposal Cost of Drilling Wastes Per Platform = **$3,089,090**
((Total Disposal Cost)/(Total Number of Platforms with Planned Drilling Program, Column 3))

Total Disposal Cost of Drilling Wastes Per Drilling Event = **$730,149**
((Total Disposal Cost)/(Total Number of Wells, Column 4 + Column 5))

Total Disposal Cost of Drilling Wastes Per New Development Well = **$1,032,234**
(Total Disposal Cost Per Barrel x Volume of Drilling Waste per an average new well, (Cost Per Barrel)x(Column 6)/(Column 4))

Total Disposal Cost of Drilling Wastes Per Recompletion Well = **$157,776**
(Total Disposal Cost Per Barrel x Drilling Waste Volume per for an average recompletion well, (Cost Per Barrel)x(Column 7)/(Column 5))

Worksheet No. 3, November 7, 1994, Page 2 of 2
Coastal Alaska Oil and Gas Drilling Industry
BAT Compliance Cost Analysis for Operators in Cook Inlet, Alaska
Zero Discharge Option by Landfill Disposal (with Closed–Loop System)

(1) Operator IDs are confidential, and are therefore discussed in a confidential supporting document (Safavi, Jan. 30, 1995).

(2), (3), (4), and (5) Some of the data in these columns are confidential, and are therefore discussed in a confidential supporting document (Safavi, Jan. 30, 1995).

(6) Total Incremental Volume of Drilling Waste from new wells is the product of the Average Volume of drilling waste generated from wells recently drilled in Cook Inlet, the Total Number of Wells scheduled for drilling, the percent of total (99%) waste discharged under the current practice, and percent reduction (69%) of drilling waste by Closed–Loop System (SAIC, Oct. 10, 1994). Based on data provided in 1993 Coastal Oil & Gas 308 Survey Questionnaires. See Worksheet No. 1 for details.

(7) Total Incremental Volume of Drilling Waste from recompleted wells is the Product of the Average Volume of drilling waste generated from the third drilled interval of wells recently drilled in Cook Inlet and the Total Number of Wells scheduled for recompletion in Cook Inlet, the percent of total (99%) waste discharged under the current practice, and percent reduction (69%) of drilling waste by closed–loop system. Based on data provided in 1993 Coastal Oil & Gas 308 Survey Questionnaires. See Worksheet No. 1 for details.

(8) Total Incremental Volume of Drilling Waste from all wells is the sum of all wastes that will be generated in Cook Inlet, Column 5 + Column 6.

(9) Total Number of Days the High Efficiency Solid Separation Equipment is Needed is assumed to be equal to the total number of days it will take to complete all drilling operations. [(Column 4 x Number of days to drill a well) + (Column 5 x Number of days to recomplete a well)]

(10) Unit Cost of High Efficiency Solid Separation Equipment was estimated based on information from drilling operations in Louisiana. Although these costs included labor, additional labor costs are included in this worksheet (Column 14) to serve as an inflation factor. See May 3, 1994 Supplemental Worksheets for more details.

(11) Total Cost of High Efficiency Solid Separation equipment is the product of total number of days the equipment will be needed and the cost of the equipment per day, Column 9 x Column 10.

(12) Retrofit Cost of solid separation equipment per platform is estimated based on the need of 450 square feet of deck space and the cost of $600 per square foot of deck space. See May 3, 1994 supplemental worksheets for more details.

(13) Total Cost of Retrofitting the platforms is the product of the unit retrofit cost and the total number of Platforms with a planned drilling program, Column 3 x Column 12.

(14) Unit Cost of Operating Solid Separation Equipment was assumed to be the same as unit cost of operating the injection equipment provided in correspondance with a 308 Survey Respondent. See confidential supporting document (Safavi, Jan. 30, 1995).

(15) Total Cost of Operating the Solid Separation Equipment is the product of the unit operating cost per day and the total number of days the equipment is needed, Column 14 x Column 9.

(16) Unit Cost of Landfilling Drilling Wastes was estimated for Operator B based on information provided by the Cook Inlet operators. See May 25, 1994 supplemental worksheets. The unit landfill cost was assumed for Operators A and C based on information provided in a particular 1993 Survey response. See confidential supporting document (Safavi, Jan. 30, 1995).

(17) Total Cost of Landfilling Drilling Waste is the product of the total volume of drilling waste and the unit cost of landfilling, Column 8 x Column 16.

(18) Total Disposal Cost of Drilling Wastes is equal to the sum of equipment, retrofit, operating, and landfilling costs, Column 11 + Column 13 + Column 15 + Column 17.

NA Not applicable.

Worksheet No. 4, November 7, 1994, Page 1 of 2
Coastal Alaska Oil and Gas Drilling Industry
BAT Compliance Cost Analysis for Operators in Cook Inlet, Alaska
Zero Discharge Option by Dedicated Well Injection

(1) Operator ID	(2) Total # of Platforms	(3) Total # of Platforms with Planned Drilling Program	(4) Total # of New Wells Scheduled 1996-2002	(5) Total # of Recompits Scheduled 1996-2002	(6) Total Incremental Volume of Waste New Wells BBLS	(7) Total Incremental Volume of Waste Recompits Wells BBLS	(8) Total Increment a Volume of Waste All Wells BBLS	(9) Total # of Injection Wells Needed	(10) Estimated Cost of Drilling an Injection Well $/well	(11) Total Cost of Injection Wells $	(12) Total # of Injection Systems Needed
A	2	1	3	1	42,631	2,172	44,803	1	1,197,173	1,197,173	1
B	12	11	27	18	383,682	39,097	422,780	8	2,000,000	16,000,000	4
C	1	1	6	0	85,263	0	85,263	2	1,197,173	2,394,346	1
Total	15	13	36	19	511,577	41,269	552,846	10	NA	19,591,519	6

Operator ID	(13) Unit Cost of Injection System/Buy $/unit	(14) Unit Cost of Injection System/Rent $/day	(15) Buying Cost of Injection System $	(16) Renting Cost of Injection System $	(17) Applied Cost of Injection System $	(18) Retrofit Cost of Injection System Per Platform $/platform	(19) Total Cost of Retrofitting Platforms $	(20) Unit Cost of Operating Injection $/day	(21) Total Cost of Operating Injection System $	(22) Total Injection Cost for all Drilling Waste $
A	1,000,000	1,400	1,000,000	267,400	267,400	750,000	750,000	1,000	191,000	2,405,573
B	1,000,000	1,400	4,000,000	3,150,000	4,000,000	750,000	8,250,000	9,260	17,584,740	45,834,740
C	1,000,000	1,400	1,000,000	478,800	1,000,000	750,000	750,000	1,000	342,000	4,486,346
Total	NA	NA	6,000,000	3,896,200	5,267,400	NA	9,750,000	NA	18,117,740	52,726,659

Total Injection Cost of Drilling Wastes for All Operators = $52,726,659
(Sum of the total costs of injection wells, injection systems, Platform Retrofits, and Operating Injection Systems)
(Column 11 +Column 17 +Column 19 +Column 21)

Total Injection Cost of Drilling Waste Per Barrel = $95
((Total Injection Cost)/(Total Volume of Drilling Wastes, Column 8))

Total Injection Cost of Drilling Wastes Per Platform = $4,055,897
((Total Injection Cost)/(Total Number of Platforms with Planned Drilling Program, Column 3))

Total Injection Cost of Drilling Wastes Per Drilling Event = $958,667
((Total Injection Cost)/(Total Number of Wells, Column 4 + Column 5))

Total Injection Cost of Drilling Wastes Per New Development Well = $1,355,297
(Total Injection Cost Per Barrel x Volume of Drilling Waste for an average new well, (Cost Per Barrel)x(Column 6)/(Column 4))

Total Injection Cost of Drilling Wastes Per Recompletion Well = $207,156
(Total Injection Cost Per Barrel x Volume of Drilling Waste for an average recompletion well, (Cost Per Barrel)x(Column 7)/(Column 5))

Worksheet No. 4, November 7, 1994, Page 2 of 2
Coastal Alaska Oil and Gas Drilling Industry
BAT Compliance Cost Analysis for Operators in Cook Inlet, Alaska
Zero Discharge Option by Dedicated Well Injection

(1) Operator IDs are confidential and are therefore discussed in a confidential supporting document (Safavi, Jan. 30, 1995).

(2), (3), (4), and (5) Some of the data in these columns are confidential, and are therefore discussed in a confidential supporting document (Safavi, Jan. 30, 1995).

(6) Total Incremental Volume of Drilling Waste from new wells is the product of the Average Volume of drilling waste generated from wells recently drilled in Cook Inlet, the Total Number of Wells scheduled for drilling, and the percent of total (99%) waste discharged under the current practice. Based on data provided in 1993 Coastal Oil & Gas 308 Survey Questionnaires. See Worksheet No. 1 for details.

(7) Total Incremental Volume of Drilling Waste from recompleted wells is the Product of the Average Volume of drilling waste generated from the third drilled interval of wells recently drilled in Cook Inlet, the Total Number of Wells scheduled for recompletion in Cook Inlet, and the percent of total (99%) generated waste discharged under the current practice. Based on information in 1993 Coastal Oil & Gas survey questionnaires. See Worksheet No. 1 for details.

(8) Total Incremental Volume of Drilling Waste from all wells is the sum of all wastes that will be generated in Cook Inlet, Column 6 + Column 7.

(9) Total Number of Injection Wells Needed is calculated based on information provided by the industry which specifies 1 dedicated well for every 4 new development wells (Schmidt, April 7, 1994). The number of dedicated wells needed for recompletions was assumed to be 1 for every 16 recompletions, (Column 4/4) + (Column 5/16).

(10) Estimated Cost of Drilling an Injection Well is calculated in Worksheet 1 or provided by the operators. See confidential supporting document (Safavi, Jan. 30, 1995).

(11) Total Cost of Injection Wells is the product of the total number of injection wells needed and the estimated cost of drilling an injection well, Column 9 x Column 10.

(12) Total Number of Injection Systems was estimated based on the assumption that 1 injection system is needed for every platform with a planned drilling program. Operator B specified the need for 4 injection systems since no more than 4 platforms are planned for drilling at one time. See confidential supporting document (Safavi, Jan. 30, 1995).

(13) Unit Cost of Injection System is provided by Operator B. See confidential supporting document (Safavi, Jan. 30, 1995).

(14) Unit Rental Cost of Injection System is provided by Operator A. See confidential supporting document (Safavi, Jan. 30, 1995).

(15) Buying Cost of Injection System is the product of the Total Number of Systems needed and Unit Buying cost of injection systems. Column 12 x Column 13.

(16) Rental Cost of Injection System is the product of the total number of days needed to complete drilling and the unit operating cost per day, [(Column 4 x number of days to drill a well) + (Column 5 x number of days to recomplete a well)] x (Column 14). The average drill time for a new development well or a recompletion was determined in Worksheet No. 1 and was assumed for Operators A and C. The numbers used for Operator B are as specified in the questionnaires.

(17) Applied Cost of Injection System is either the buying or the renting cost of injection systems depending on which is economically most feasible.

(18) Retrofit Cost of Injection System was provided by Operator B. See confidential supporting document (Safavi, Jan. 30, 1995).

(19) Total Cost of Retrofitting Platforms is the product of the Total Number of Platforms with planned drilling programs and the Unit Cost of Retrofitting Platforms, Column 3 x Column 18. This cost is based on the assumption that each platform with a planned drilling program must be retrofitted for an injection system.

(20) Unit Cost of Operating Injection Systems is provided by operators or estimated from information provided by the Cook Inlet Operators. See May 31, 1994 Supplemental Worksheet for more details.

(21) Total Cost of Operating Injection System is the product of the total number of days needed to complete drilling and the unit operating cost per day, [(Column 4 x number of days to drill a well) + (Column 5 x number of days to recomplete a well)] x (Column 20). The average drill time for a new development well or a recompletion was determined in Worksheet No. 1 and was assumed for all operators.

NA Not applicable.

Worksheet No. 5, November 7, 1994, Page 1 of 2
Coastal Alaska Oil and Gas Drilling Industry
BAT Compliance Cost Analysis for Operators in Cook Inlet, Alaska
Zero Discharge Option by Combined Landfill and Well Injection

(1) Operator ID	(2) Total # of Platforms	(3) Total # of Platforms with Planned Drilling Program	(4) Total # of New Wells Scheduled 1996-2002	(5) Total # of Recompltn Scheduled 1996-2002	(6) Total Incremental Volume of Waste New Wells BBLS	(7) Total Incremental Volume of Waste Recompltn Wells BBLS	(8) Total Incremental Volume of Waste All Wells BBLS
A	2	1	3	1	42,631	2,172	44,803
B	12	11	27	18	383,682	39,097	422,780
C	1	1	6	0	85,263	0	85,263
Total	15	13	36	19	511,577	41,269	552,846

Operator ID	(9) Total Cost Landfill Without Closed-Loop Method	(10) Total Cost Landfill With Closed-Loop Method	(11) Total Cost Injection Well Method	(12) Disposal Method Most Likely Selected	(13) Total Disposal Cost Based on Selected Method
A	$9,095,098	$7,099,518	$2,405,573	Well Injection	$2,405,573
B	$16,488,401	$19,854,096	$45,834,740	Landfill/Without	$16,488,401
C	$17,308,340	$13,204,555	$4,486,346	Well Injection	$4,486,346
Total	$42,891,839	$40,158,169	$52,726,659	NA	$23,380,320

Total Disposal Cost of Drilling Wastes for All Operators = **$23,380,320**
(Sum of the total costs for each operator, Column 13)

Total Disposal Cost Per Barrel of Drilling Waste = **$42**
((Total Disposal Cost)/(Total Volume of Drilling Wastes, Column 8))

Total Dispoal Cost of Drilling Wastes Per Platform = **$1,798,486**
((Total Disposal Cost)/(Total Platforms with Planned Drilling Program))
(Column 13)/(Column 3)

Total Dispoal Cost of Drilling Wastes Per Drilling Event = **$425,097**
((Total Disposal Cost)/(Total Number of Wells, Column 4 + Column 5))

Total Dispoal Cost of Drilling Wastes Per New Development Well = **$600,973**
(Total Disposal Cost Per Barrel x Volume of Drilling Waste for an average new well, (Cost per Barrel)x(Column 6)/(Column 4))

Total Disposal Cost of Drilling Wastes Per Recompletion Well = **$91,858**
(Total Disposal Cost Per Barrel x Volume of Drilling Waste for an average recompletion, (Cost Per Barrel)x(Column 7)/(column 5)

Worksheet No. 5, November 7, 1994, Page 2 of 2
Coastal Alaska Oil and Gas Drilling Industry
BAT Compliance Cost Analysis for Operators in Cook Inlet, Alaska
Zero Discharge Option by Combined Landfill and Well Injection

(1) Operator IDs are confidential, and are therefore discussed in a confidential supporting document (Safavi, Jan. 30, 1995).

(2), (3), (4), and (5) Some of the data in these columns are confidential, and are therefore discussed in a confidential supporting document (Safavi, Jan. 30, 1995).

(6) Total Incremental Volume of Drilling Waste from new wells is the product of the Average Volume of drilling waste generated from wells recently drilled in Cook Inlet, the Total Number of Wells scheduled for drilling, and the percent of total (99%) waste discharged under the current practice. Based on data provided in 1993 Coastal Oil & Gas 308 Survey Questionnaires. See Worksheet No. 1 for details.

(7) Total Incremental Volume of Drilling Waste from recompleted wells is the Product of the Average Volume of drilling waste generated from the third drilled interval of wells recently drilled in Cook Inlet, the Total Number of Wells scheduled for recompletion in Cook Inlet, and the percent of total (99%) generated waste discharged under the current practice. Based on information in 1993 Coastal Oil & Gas survey questionnaires. See Worksheet No. 1 for details.

(8) Total Incremental Volume of Drilling Waste from all wells is the sum of all wastes that will be generated in Cook Inlet, Column 6 + Column 7.

(9) Total Cost of Landfill Without Closed–Loop Method is as calculated in Worksheet No. 2.

(10) Total Cost of Landfill With Closed–Loop Method is as calculated in Worksheet No. 3.

(11) Total Cost of Dedicated Well Injection Option is as calculated in Worksheet No. 4.

(12) Disposal Method Most Likely Selected is based on the operator's current practices, information provided by the operator, and disposal costs.

(13) Total Disposal Cost is copied from the appropriate column as specified in Column 12. (Values from Columns 9, 10, and 11)

Worksheet No. 1T, November 7, 1994, Page 1 of 2
Coastal Alaska Oil and Gas Drilling Industry
Toxicity Limitation Compliance Cost Analysis for Operations in Cook Inlet, Alaska
Cost Estimation for Drilling an Average Injection Well

(1) Operator ID	(2) Well ID	(3) DFS-01 Depth feet	(4) DFS-02 Depth feet	(5) DFS-03 Depth feet	(6) Well Total Depth feet	(7) DFS-01 Drill Time days	(8) DFS-01 Workday hours	(9) DFS-02 Drill Time days	(10) DFS-02 Workday hours	(11) DFS-03 Drill Time days	(12) DFS-03 Workday hours	(13) DFS-01 M & C bbls	(14) DFS-02 M & C bbls	(15) DFS-03 M & C bbls	(16) Total M & C bbls	(17) Average Cuttings % of Total
A	1A	1,389	8,477	2,029	11,895	9	6	21	14	20	11	1,528	9,325	2,232	13,085	NA
A	2A	1,256	8,368	2,176	11,800	3	13	32	12	20	8	1,213	8,081	2,101	11,395	NA
A	3A	1,155	8,642	2,343	12,140	5	9	27	13	47	9	1,361	10,180	2,760	14,300	NA
B	1B	2,110	7,999	860	10,969	23	23	30	23	13	23	3,313	7,334	1,334	11,981	19
B	2B	4,120	5,962	1,478	11,560	NA	NA	30	12	12	12	NA	9,558	1,583	NA	NA
B	3B	4,017	5,745	2,068	11,830	12	12	17	12	12	12	6,065	7,606	2,326	15,997	NA
B	4B	3,823	6,240	2,100	12,163	15	12	20	12	17	12	7,504	8,838	3,024	19,366	NA
AVERAGE		2,553	7,348	1,865	11,765	11	13	25	14	20	12	3,497	8,703	2,194	14,354	19

Operator ID	Well ID	(18) DFS-01 Drill Time hours	(19) DFS-02 Drill Time hours	(20) DFS-03 Drill Time hours	(21) Well Total Drill Time hours	(22) Total Well Drill Cost ($1,000)	(23) Average Drill Rate $/hr	(24) DFS-01 Drill Cost $	(25) DFS-02 Drill Cost $	(26) DFS-03 Drill Cost $	(27) DFS-01 Unit Cost $/ft	(28) DFS-02 Unit Cost $/ft	(29) DFS-03 Unit Cost $/ft	(30) DFS-01 Unit M&C bbls/ft	(31) DFS-02 Unit M&C bbls/ft	(32) DFS-03 Unit M&C bbls/ft
A	1A	54	294	220	568	3,250	5,722	308,979	1,682,218	1,258,803	222	198	620	1.1	1.1	1.1
A	2A	39	384	160	583	3,150	5,403	210,720	2,074,786	864,494	168	248	397	1.0	1.0	1.0
A	3A	45	351	423	819	4,200	5,128	230,769	1,800,000	2,169,231	200	208	926	1.2	1.2	1.2
B	1B	529	690	299	1,518	3,716	2,448	1,294,970	1,689,091	731,939	614	211	851	1.6	0.9	1.6
B	2B	NA	360	144	NA	6,125	NA	NA	NA	NA	NA	NA	NA	NA	1.6	1.1
B	3B	144	204	144	492	4,665	9,482	1,365,366	1,934,268	1,365,366	340	337	660	1.5	1.3	1.1
B	4B	180	240	204	624	5,408	8,667	1,560,000	2,080,000	1,768,000	408	333	842	2.0	1.4	1.4
AVERAGE		165	360	228	767	4,359	6,142	828,467	1,876,727	1,359,639	325	256	716	1.4	1.2	1.2

Average Cost of Drilling a 4000 Foot Injection Well = **$1,197,173**
(Sum of the costs of drilling the first 2,500 feet using the average cost of first drilling fluid system, DFS-01, and the cost of drilling the last 1,500 feet using the average cost of the second drilling fluid system, DFS-02, (2,500 x Column 27) + (1,500 x Column 28))

Average Muds and Cuttings Generated from Drilling a 4000 Foot Injection Well (BBLS) = **5,275**
(Sum of the muds and cuttings (M&C) generated from drilling the first 2,500 feet of well, using the average unit volume M&C of DFS-01, and M&C generated from drilling the last 1,500 feet of the well, using the average unit volume M&C of DFS-02, (2,500 x Column 30) + (1,500 x Column 31))

Average Number of Days for Drilling an Average New Well = **57**
(Sum of the average number of days for each drilled interval)
(Column 7 + Column 9 + Column 11)

Average Number of Days for Recompleting a Well = **20**
(Set equal to the average number of days spent drilling the third drilled interval of new wells, Column 11)

Worksheet No. 1T, November 7, 1994, Page 2 of 2
Coastal Alaska Oil and Gas Drilling Industry
Toxicity Limitation Compliance Cost Analysis for Operations in Cook Inlet, Alaska
Cost Estimation for Drilling an Average Injection Well

(1) Operator IDs are confidential, and are therfore discussed in a confidential supporting document (Safavi, Jan. 30, 1995).

(2) Well IDs are confidential, and are therefore discussed in a confidential supporting document (Safavi, Jan. 30, 1995).

(3), (4), and (5) The depth of each drilling fluid system (DFS) was obtained from the 308 questionnaire or by direct contanct with the operator.

(6) The final depth to which the well was drilled is the sum of all drilling intervals, Column 3 + Column 4 + Column 5.

(7), (8), (9), (10), (11), and (12) Drilling time for each drilling interval was obtained from 308 Quetionnaires or obtained directly from the operators.

(13), (14), and (15) Muds and Cuttings (M&C) Volumes are as specified in the 308 Questionnaires, obtained directly from the operators, or calculated from the reported total volume by weighted average based on the depth of each interval.

(16) Total muds and cuttings generated from each well are as reported in the 308 Questionnaires or the sum of muds and cuttings from all drilled intervals.

(17) Average percent of total volume of drilling waste as cuttings was calculated by averaging reported percentages for each drilled interval in the 308 Questionnaires. Only one facility reported cuttings fractions.

(18) Total hours of drilling the first interval is the product of total number of drilling days and average number of drilling hours in a day. Column 7 x Column 8.

(19) Total hours of drilling the second interval is the product of total number of drilling days and average number of drilling hours in a day. Column 9 x Column 10.

(20) Total hours of drilling the third interval is the product of total number of drilling days and average number of drilling hours in a day. Column 11 x Column 12.

(21) Total drilling hours is the sum of total drilling hours for each drilling interval. Column 18 + Column 19 + Column 20.

(22) Total drilling costs were obtained from the 308 Questionnaires.

(23) The average hourly drilling cost for each well is calculated by dividing the total cost of drilling by the number of hours spent to drill the well, Column 22/Column21.

(24) Cost of drilling the first interval is calculated by multiplying the average hourly drilling cost rate for the entire well by the total hours spent drilling the first interval, Column 23 x Column 18.

(25) Cost of drilling the second interval is calculated by multiplying the average hourly drilling cost rate for the entire well by the total hours spent drilling the second interval, Column 23 x Column 19.

(26) Cost of drilling the third interval is calculated by multiplying the average hourly drilling cost rate for the entire well by the total hours spent drilling the third interval, Column 23 x Column 20.

(27) The cost of drilling per unit depth of the first interval is calculated by dividing the total cost of drilling the interval by total depth of the interval, Column24/Column 3.

(28) The cost of drilling per unit depth of the second interval is calculated by dividing the total cost of drilling the interval by total depth of the interval, Column25/Column 4.

(29) The cost of drilling per unit depth of the third interval is calculated by dividing the total cost of drilling the interval by total depth of the interval, Column26/Column 5.

(30) The unit muds and cuttings generated per foot of the first drilled interval is calculated by dividing the total volume of muds and cuttings for the interval by the total depth of the interval, Column 14/Column 3.

(31) The unit muds and cuttings generated per foot of the second drilled interval is calculated by dividing the total volume of muds and cuttings for the interval by the total depth of the interval, Column 15/Column 4.

(32) The unit muds and cuttings generated per foot of the third drilled interval is calculated by dividing the total volume of muds and cuttings for the interval by the total depth of the interval, Column 16/Column 5.

NA Data not available or not applicable.

Note: A 4000-foot injection well is assumed based on information provided by Operator B (Safavi, Jan. 30, 1995).

Worksheet No. 2T, November 7, 1994, Page 1 of 2
Coastal Alaska Oil and Gas Drilling Industry
BAT Compliance Cost Analysis for Operators in Cook Inlet, Alaska
1,000,000 Toxicity Limitation Option by Land Disposal (Without Closed–Loop System)

(1) Operator ID	(2) Total # of Platforms	(3) Total # of Platforms With Planned Drilling Program	(4) Total # of New Wells Scheduled 1996 – 2002	(5) Total # of Recompits Scheduled 1996 – 2002	(6) Total Incremental Volume of Waste New Wells BBLS	(7) Total Incremental Volume of Waste Recompit Wells BBLS	(8) Total Incremental Volume of Waste All Wells BBLS	(9) Unit Cost of Disposing Drilling Waste $/BBL	(10) Total Disposal Cost New Wells $	(11) Total Disposal Cost Recompits Wells $	(12) Total Disposal Cost All Wells $
A	2	1	3	1	7,247	369	7,617	203	1,471,209	74,958	1,546,167
B	12	11	27	18	65,226	6,647	71,873	39	2,543,814	259,214	2,803,028
C	1	1	6	0	14,495	0	14,495	203	2,642,268	0	2,642,268
Total	15	13	36	19	86,968	7,016	93,984	NA	6,657,291	334,171	6,991,463

Total Disposal Cost of Drilling Wastes for All Operators = **$6,991,463**
(Sum of Disposal Costs for All Operators, Column 12)

Total Disposal Cost Per Barrel of Drilling Waste = **$74**
(Total Disposal Cost/Total Volume of Drilling Wastes, Column 12/Column 8)

Total Disposal Cost of Drilling Wastes Per Platform = **$537,805**
(Total Disposal Cost/Total Number of Platforms with Planned Drilling, Column 12/Column 3)

Total Disposal Cost of Drilling Wastes Per Drilling Event = **$127,118**
((Total Disposal Cost)/(Total Number of New and Recompletion Wells), Column 12/(Column 4 + Column 5))

Total Disposal Cost of Drilling Wastes Per New Development Well = **$179,710**
(Total Disposal Cost Per Barrel x Volume of Drilling Waste from an Average new Well, (Cost Per Barrel)x(Column 6)/(Column 4))

Total Disposal Cost of Drilling Wastes Per Recompletion Well = **$27,469**
(Total Disposal Cost Per Barrel x Volume of Drilling Waste from an Average Recompletion, (Cost Per Barrel)x(Column 7)/(Column 5))

Worksheet No. 2T, November 7, 1994, Page 2 of 2
Coastal Alaska Oil and Gas Drilling Industry
BAT Compliance Cost Analysis for Operators in Cook Inlet, Alaska
1,000,000 Toxicity Limitation Option by Land Disposal (Without Closed–Loop System)

(1) Operator IDs are confidential, and are therefore discussed in a confidential supporting document (Safavi, Jan. 30, 1995).

(2), (3), (4), and (5) Some of the data in these columns are confidential, and are therefore discussed in a confidential supporting document (Safavi, Jan. 30, 1995).

(6) Total Incremental Volume of Drilling Waste from new wells is the product of the Average Volume of drilling waste generated from wells recently drilled in Cook Inlet, the Total Number of Wells scheduled for drilling, Percent of total (99%) drilling waste discharged under current practice, and percent of drilling waste (17%) failing the toxicity limitation (SAIC, Sept. 30, 1994). Based on data provided in 1993 Coastal Oil & Gas 308 Survey Questionnaires.

(7) Total Incremental Volume of Drilling Waste from recompleted wells is the Product of the Average Volume of drilling waste generated from the third drilled interval of wells recently drilled in Cook Inlet and the total number of wells scheduled for recompletion in Cook Inlet, percent of total (99%) drilling waste discharged under current practice, and percent of drilling waste (17%) failing the toxicity limitation (SAIC, Sept 30, 1994). Based on information provided in 1993 Coastal Oil & Gas Industry Survey Questionnaires. See Worksheet No. 1 for more details.

(8) Total Incremental Volume of Drilling Waste from all wells is the sum of all incremental wastes that will be generated in Cook Inlet, Column 5 + Column 6.

(9) Unit disposal costs for landfill disposal of muds and cuttings generated in Cook Inlet. Data were obtained from 308 Survey Questionnaires or estimated from information provided by Cook Inlet operators. See also the May 25, 1994 Supplemental Worksheets for more details.

(10) Total Disposal Cost for new drilling is the product of Unit Disposal Cost and Total Volume of Drilling Waste from drilling new wells, Column (9) x Column (6).

(11) Total Disposal Cost for recompletions is the product of Unit Disposal Cost and Total Volume of Drilling Waste from Recompleting existing wells, Column (9) x Column (7).

(12) Total Disposal Cost of drilling wastes from all wells or all drilling activities, Column (10) + Column (11).

NA Not applicable.

Worksheet No. 3T, November 7, 1994, Page 1 of 2
Coastal Alaska Oil and Gas Drilling Industry
BAT Compliance Cost Analysis for Operators in Cook Inlet, Alaska
1,000,000 Toxicity Limitation Option by Landfill Disposal (with Closed–Loop System)

(1) Operator ID	(2) Total # of Platforms	(3) Total # of Platforms with Planned Drilling Program	(4) Total # of New Wells Scheduled 1996 – 2002	(5) Total # of Recompits Scheduled 1996 – 2002	(6) Total Incremental Volume of Waste New Wells bbls	(7) Total Incremental Volume of Waste Recompits Wells bbls	(8) Total Incremental Volume of Waste All Wells bbls	(9) Total # of Days High Efficiency Solid Separation Equipment Needed	(10) Unit Cost of Solid Separation Equipment $/day/unit	(11) Total Cost of High Efficiency Solid Separation $
A	2	1	3	1	5,001	255	5,255	191	1,900	362,900
B	12	11	27	18	45,006	4,586	49,592	1,899	1,900	3,608,100
C	1	1	6	0	10,001	0	10,001	342	1,900	649,800
Total	15	13	36	19	60,008	4,841	64,849	2,432	NA	4,620,800

Operator ID	(12) Retrofit Cost of Equipment Per Platform $/platform	(13) Total Cost of Retrofitting Platforms $	(14) Unit Cost of Operating Equipment $/day	(15) Total Cost of Operating Equipment $	(16) Unit Cost of Landfilling Drilling Waste $	(17) Total Cost of Landfilling Drilling Waste $	(18) Total Disposal Cost of Drilling Waste $
A	270,000	270,000	1,000	191,000	203	1,066,855	1,890,755
B	270,000	2,970,000	1,000	1,899,000	39	1,934,089	10,411,189
C	270,000	270,000	1,000	342,000	203	2,030,268	3,292,068
Total	810,000	NA	NA	2,432,000	445	5,031,213	15,594,013

Total Disposal cost of Drilling Waste for All Operators = **$15,594,013**
(Sum of Disposal Costs for All Operators, Column 18)

Total Disposal Cost of Drilling Waste Per Barrel = **$240**
((Total Disposal Cost)/(Total Volume of Drilling Wastes, Column 8))

Total Disposal Cost of Drilling Wastes Per Platform = **$1,199,539**
((Total Disposal Cost)/(Total Number of Platforms with Planned Drilling Program, Column 3))

Total Disposal Cost of Drilling Wastes Per Drilling Event = **$283,528**
((Total Disposal Cost)/(Total Number of Wells, Column 4 + Column 5))

Total Disposal Cost of Drilling Wastes Per New Development Well = **$400,832**
(Total Disposal Cost Per Barrel x Volume of Drilling Waste per an average new well, (Cost Per Barrel)x(Column 6)/(Column 4))

Total Disposal Cost of Drilling Wastes Per Recompletion Well = **$61,267**
(Total Disposal Cost Per Barrel x Drilling Waste Volume per for an average recompletion well, (Cost Per Barrel)x(Column 7)/(Column 5))

Worksheet No. 3T, November 7, 1994, Page 2 of 2
Coastal Alaska Oil and Gas Drilling Industry
BAT Compliance Cost Analysis for Operators in Cook Inlet, Alaska
1,000,000 Toxicity Limitation Option by Landfill Disposal (with Closed–Loop System)

(1) Operator IDs are confidential, and are therefore discussed in a confidential supporting document (Safavi, Jan. 30, 1995).

(2), (3), (4), and (5) Some of the data in these columns are confidential, and are therefore discussed in a confidential supporting document (Safavi, Jan. 30, 1995).

(6) Total Incremental Volume of Drilling Waste from new wells is the product of the Average Volume of drilling waste generated from wells recently drilled in Cook Inlet, the Total Number of Wells scheduled for drilling, percent of total (99%) drilling waste discharged under current practice, the percent of drilling waste (17%) failing the toxicity limitation (SAIC, Sept 30, 1994), and percent reduction (69%) of drilling waste by closed–loop system (SAIC, Oct. 10, 1994). Based on data provided in 1993 Coastal Oil and Gas 308 Survey Questionnaires.

(7) Total Incremental Volume of Drilling Waste from recompleted wells is the Product of the Average Volume of drilling waste generated from the third drilled interval of wells recently drilled in Cook Inlet and the total number of wells scheduled for recompletion in Cook Inlet, percent of total (99%) drilling waste discharged under current practice, the percent of drilling waste (17%) failing the toxicity limitation (SAIC, Sept 30, 1994), and the percent reduction (69%) of drilling waste by closed loop system (SAIC, Oct. 10, 1994). Based on information provided in 1993 Coastal Oil & Gas Industry Survey Questionnaires. See Worksheet No. 1 for more details.

(8) Total Incremental Volume of Drilling Waste from all wells is the sum of all wastes that will be generated in Cook Inlet, Column 5 + Column 6.

(9) Total Number of Days the High Efficiency Solid Separation Equipment is Needed is assumed to be equal to the total number of days it will take to complete all drilling operations. [(Column 4 x Number of days to drill a well) + (Column 5 x Number of days to recomplete a well)]

(10) Unit Cost of High Efficiency Solid Separation Equipment was estimated based on information from drilling operations in Louisiana. Although these costs included labor, additional labor costs are included in this worksheet (Column 14) to serve as an inflation factor. See May 3, 1994 Supplemental Worksheets for more details.

(11) Total Cost of High Efficiency Solid Separation equipment is the product of total number of days the equipment will be needed and the cost of the equipment per day, Column 9 x Column 10.

(12) Retrofit Cost of solid separation equipment per platform is estimated based on the need of 450 square feet of deck space and the cost of $600 per square foot of deck space. See May 3, 1994 supplemental worksheets for more details.

(13) Total Cost of Retrofitting the platforms is the product of the unit retrofit cost and the total number of Platforms with a planned drilling program, Column 3 x Column 12.

(14) Unit Cost of Operating Solid Separation Equipment was assumed to be the same as unit cost of operating the injection equipment provided in correspondence with a 308 Survey respondent. See confidential supporting document (Safavi, Jan. 30 1995).

(15) Total Cost of Operating the Solid Separation Equipment is the product of the unit operating cost per day and the total number of days the equipment is needed, Column 14 x Column 9.

(16) Unit Cost of Landfilling Drilling Wastes was estimated for Operator B based on information provided by the Cook Inlet operators. See May 25, 1994 supplemental worksheets. The unit landfill cost was assumed for Operators A and C based on information provided in a particular 1993 survey response. See confidential supporting document (Safavi, Jan. 30, 1995).

(17) Total Cost of Landfilling Drilling Waste is the product of the total volume of drilling waste and the unit cost of landfilling, Column 8 x Column 16.

(18) Total Disposal Cost of Drilling Wastes is equal to the sum of equipment, retrofit, operating, and landfilling costs, Column 11 + Column 13 + Column 15 + Column 17.

NA Not applicable.

Worksheet No. 4T, November 7, 1994, Page 1 of 2
Coastal Alaska Oil and Gas Drilling Industry
BAT Compliance Cost Analysis for Operators in Cook Inlet, Alaska
1,000,000 Toxicity Limitation Option by Dedicated Well Injection

(1) Operator ID	(2) Total # of Platforms	(3) Total # of Platforms with Planned Drilling Program	(4) Total # of New Wells Scheduled 1996 – 2002	(5) Total # of Recompits Scheduled 1996 – 2002	(6) Total Incremental Volume of Waste New Wells BBLS	(7) Total Incremental Volume of Waste Recompits Wells BBLS	(8) Total Increment a Volume of Waste All Wells BBLS	(9) Total # of Injection Wells Needed	(10) Estimated Cost of Drilling an Injection Well $/well	(11) Total Cost of Injection Wells $	(12) Total # of Injection Systems Needed
A	2	1	3	1	7,247	369	7,617	1	1,197,173	1,197,173	1
B	12	11	27	18	65,226	6,647	71,873	4	2,000,000	8,000,000	4
C	1	1	6	0	14,495	0	14,495	1	1,197,173	1,197,173	1
Total	15	13	36	19	86,968	7,016	93,984	6	NA	10,394,346	6

Operator ID	(13) Unit Cost of Injection System/Buy $/unit	(14) Unit Cost of Injection System/Rent $/day	(15) Buying Cost of Injection System $	(16) Renting Cost of Injection System $	(17) Applied Cost of Injection System $	(18) Retrofit Cost of Injection System Per Platform $/platform	(19) Total Cost of Retrofitting Platforms $	(20) Unit Cost of Operating Injection $/day	(21) Total Cost of Operating Injection System $	(22) Total Injection Cost for all Drilling Waste $
A	1,000,000	1,400	1,000,000	267,400	267,400	750,000	750,000	1,000	191,000	2,405,573
B	1,000,000	1,400	4,000,000	3,150,000	4,000,000	750,000	8,250,000	9,260	17,584,740	37,834,740
C	1,000,000	1,400	1,000,000	478,800	478,800	750,000	750,000	1,000	342,000	2,767,973
Total	NA	NA	6,000,000	3,896,200	4,746,200	NA	9,750,000	NA	18,117,740	43,008,286

Total Injection Cost of Drilling Wastes for All Operators = **$43,008,286**
(Sum of the total costs of injection wells, injection systems, Platform Retrofits, and Operating Injection Systems)
(Column 11 +Column 17 +Column 19 +Column 21)

Total Injection Cost of Drilling Waste Per Barrel = **$458**
((Total Injection Cost)/(Total Volume of Drilling Wastes, Column 8))

Total Injection Cost of Drilling Wastes Per Platform = **$3,308,330**
((Total Injection Cost)/(Total Number of Platforms with Planned Drilling Program, Column 3))

Total Injection Cost of Drilling Wastes Per Drilling Event = **$781,969**
((Total Injection Cost)/(Total Number of Wells, Column 4 + Column 5))

Total Injection Cost of Drilling Wastes Per New Development Well = **$1,105,494**
(Total Injection Cost Per Barrel x Volume of Drilling Waste for an average new well, (Cost Per Barrel)x(Column 6)/(Column 4))

Total Injection Cost of Drilling Wastes Per Recompletion Well = **$168,974**
(Total Injection Cost Per Barrel x Volume of Drilling Waste for an average recompletion well, (Cost Per Barrel)x(Column 7)/(Column 5))

Worksheet No. 4, November 7, 1994, Page 2 of 2
Coastal Alaska Oil and Gas Drilling Industry
BAT Compliance Cost Analysis for Operators in Cook Inlet, Alaska
Zero Discharge Option by Dedicated Well Injection

(1) Operator IDs are confidential and are therefore discussed in a confidential supporting document (Safavi, Jan. 30, 1995).

(2), (3), (4), and (5) Some of the data in these columns are confidential, and are therefore discussed in a confidential supporting document (Safavi, Jan. 30, 1995).

(6) Total Incremental Volume of Drilling Waste from new wells is the product of the Average Volume of drilling waste generated from wells recently drilled in Cook Inlet, the Total Number of Wells scheduled for drilling, and the percent of total (99%) waste discharged under the current practice. Based on data provided in 1993 Coastal Oil & Gas 308 Survey Questionnaires. See Worksheet No. 1 for details.

(7) Total Incremental Volume of Drilling Waste from recompleted wells is the Product of the Average Volume of drilling waste generated from the third drilled interval of wells recently drilled in Cook Inlet, the Total Number of Wells scheduled for recompletion in Cook Inlet, and the percent of total (99%) generated waste discharged under the current practice. Based on information in 1993 Coastal Oil & Gas survey questionnaires. See Worksheet No. 1 for details.

(8) Total Incremental Volume of Drilling Waste from all wells is the sum of all wastes that will be generated in Cook Inlet, Column 6 + Column 7.

(9) Total Number of Injection Wells Needed is calculated based on information provided by the industry which specifies 1 dedicated well for every 4 new development wells (Schmidt, April 7, 1994). The number of dedicated wells needed for recompletions was assumed to be 1 for every 16 recompletions, (Column 4/4) + (Column 5/16).

(10) Estimated Cost of Drilling an Injection Well is calculated in Worksheet 1 or provided by the operators. See confidential supporting document (Safavi, Jan. 30, 1995).

(11) Total Cost of Injection Wells is the product of the total number of injection wells needed and the estimated cost of drilling an injection well, Column 9 x Column 10.

(12) Total Number of Injection Systems was estimated based on the assumption that 1 injection system is needed for every platform with a planned drilling program. Operator B specified the need for 4 injection systems since no more than 4 platforms are planned for drilling at one time. See confidential supporting document (Safavi, Jan. 30, 1995).

(13) Unit Cost of Injection System is provided by Operator B. See confidential supporting document (Safavi, Jan. 30, 1995).

(14) Unit Rental Cost of Injection System is provided by Operator A. See confidential supporting document (Safavi, Jan. 30, 1995).

(15) Buying Cost of Injection System is the product of the Total Number of Systems needed and Unit Buying cost of injection systems. Column 12 x Column 13.

(16) Rental Cost of Injection System is the product of the total number of days needed to complete drilling and the unit operating cost per day, [(Column 4 x number of days to drill a well) + (Column 5 x number of days to recomplete a well)] x (Column 14). The average drill time for a new development well or a recompletion was determined in Worksheet No. 1 and was assumed for Operators A and C. The numbers used for Operator B are as specified in the questionnaires.

(17) Applied Cost of Injection System is either the buying or the renting cost of injection systems depending on which is economically most feasible.

(18) Retrofit Cost of Injection System was provided by Operator B. See confidential supporting document (Safavi, Jan. 30, 1995).

(19) Total Cost of Retrofitting Platforms is the product of the Total Number of Platforms with planned drilling programs and the Unit Cost of Retrofitting Platforms, Column 3 x Column 18. This cost is based on the assumption that each platform with a planned drilling program must be retrofitted for an injection system.

(20) Unit Cost of Operating Injection Systems is provided by operators or estimated from information provided by the Cook Inlet Operators. See May 31, 1994 Supplemental Worksheet for more details.

(21) Total Cost of Operating Injection System is the product of the total number of days needed to complete drilling and the unit operating cost per day, [(Column 4 x number of days to drill a well) + (Column 5 x number of days to recomplete a well)] x (Column 20). The average drill time for a new development well or a recompletion was determined in Worksheet No. 1 and was assumed for all operators.

NA Not applicable.

Worksheet No. 5T, November 7, 1994, Page 1 of 2
Coastal Alaska Oil and Gas Drilling Industry
BAT Compliance Cost Analysis for Operators in Cook Inlet, Alaska
1,000,000 Toxicity Limitation Option by Combined Landfill, Well Injection, Annular Injection

(1) Operator ID	(2) Total # of Platforms	(3) Total # of Platforms with Planned Drilling Program	(4) Total # of New Wells Scheduled 1996 – 2002	(5) Total # of Recompls Scheduled 1996 – 2002	(6) Total Incremental Volume of Waste New Wells BBLS	(7) Total Incremental Volume of Waste Recompls Wells BBLS	(8) Total Incremental Volume of Waste All Wells BBLS
A	2	1	3	1	7,247	369	7,617
B	12	11	27	18	65,226	6,647	71,873
C	1	1	6	0	14,495	0	14,495
Total	15	13	36	19	86,968	7,016	93,984

Operator ID	(9) Total Cost Landfill Without Closed-Loop Method	(10) Total Cost Landfill With Closed-Loop Method	(11) Total Cost Injection Well Method	(12) Disposal Method Most Likely Selected	(13) Total Disposal Cost Based on Selected Method
A	$1,546,167	$1,890,755	$2,405,573	Landfill/Without	$1,546,167
B	$2,803,028	$10,411,189	$37,834,740	Landfill/Without	$2,803,028
C	$2,642,268	$3,292,068	$2,767,973	Landfill/Without	$2,642,268
Total	$6,991,463	$15,594,012	$43,008,286	NA	$6,991,463

Total Disposal Cost of Drilling Wastes for All Operators = $6,991,463
(Sum of the total costs for each operator, Column 13)

Total Disposal Cost Per Barrel of Drilling Waste = $74
((Total Disposal Cost)/(Total Volume of Drilling Wastes, Column 8))

Total Disposal Cost of Drilling Wastes Per Platform = $537,805
((Total Disposal Cost)/(Total Platforms with Planned Drilling Program))
(Column 13)/(Column 3)

Total Disposal Cost of Drilling Wastes Per Drilling Event = $127,118
((Total Disposal Cost)/(Total Number of Wells, Column 4 + Column 5))

Total Dispoal Cost of Drilling Wastes Per New Development Well = $179,710
(Total Disposal Cost Per Barrel x Volume of Drilling Waste for an average new well, (Cost per Barrel)x(Column 6)/(Column 4))

Total Disposal Cost of Drilling Wastes Per Recompletion Well = $27,469
(Total Disposal Cost Per Barrel x Volume of Drilling Waste for an average recompletion, (Cost Per Barrel)x(Column 7)/(column 5)

Worksheet No. 5T, November 7, 1994, Page 2 of 2
Coastal Alaska Oil and Gas Drilling Industry
BAT Compliance Cost Analysis for Operators in Cook Inlet, Alaska
1,000,000 Toxicity Limitation Option by Combined Landfill and Well Injection

(1) Operator IDs are confidential, and are therefore discussed in a confidential supporting document (Safavi, Jan. 30, 1995).

(2), (3), (4), and (5) Some of the data in these columns are confidential, and are therefore discussed in a confidential supporting document (Safavi, Jan. 30, 1995).

(6) Total Incremental Volume of Drilling Waste from new wells is the product of the Average Volume of drilling waste generated from wells recently drilled in Cook Inlet, the Total Number fo Wells scheduled for drilling Percent of total (99%) drilling waste discharged under current practice, and percent of drilling waste (17%) failing the toxicity limitation (SAIC, Sept. 30, 1994). Based on data in the 1993 Coastal Oil & Gas 308 Survey Questionnaires.

(7) Total Incremental Volume of Drilling Waste from recompleted wells is the Product of the Average Volume of drilling waste generated from the third drilled interval of wells recently drilled in Cook Inlet and the total number of wells scheduled for recompletion in Cook Inlet, percent of total (99%) drilling waste discharged under current practice, and percent of drilling waste (17%) failing the toxicity limitation (SAIC, Sept. 30, 1994). Based on information provided in 1993 Coastal Oil & Gas Industry Survey Questionnaires. See Worksheet No. 1 for more details.

(8) Total Incremental Volume of Drilling Waste from all wells is the sum of all wastes that will be generated in Cook Inlet, Column 6 + Column 7.

(9) Total Cost of Landfill without Closed–loop Method is as calculated in Worksheet No. 2T.

(10) Total Cost of Landfill with Closed–loop Method is as calculated in Worksheet 3T.

(11) Total Cost of Dedicated Well Injection Option is as calculated in Worksheet No. 4T.

(12) Disposal Method Most Likely Selected is based on the most feasible cost estimated.

(13) Total Disposal Cost is copied from the appropriate column as specified in Column 12. (Values from Columns 9, 10, and 11)

APPENDIX X-2

Calculations Unit Onshore Disposal Cost For

Operator B

Appendix X-2

Landfill Disposal Cost Estimation for Operator B

LIST OF ASSUMPTIONS:

1. 8 barrel muds/cuttings boxes (4'x4'x4') are used at the cost of $125 per box.[1,2]

2. Supply boats are used to transport drilling waste to temporary onshore storage on the east side of the inlet at the rate of $4,000 per day including loading and unloading costs.[3]

3. Each boat will have 130'x 28' deck space with cargo not higher than 12 feet and center of gravity less than 3 feet or a capacity of 227 8-barrel boxes arranged on deck in one layer.[1,3]

4. Trucks are used to transport muds/cuttings to the temporary onshore storage area at the rate of $300 per load where each load could include 12 boxes.[2]

5. Barges are used for transportation from east Cook Inlet docking area to the west Cook Inlet landfill at the rate of $6,000 per day with the capacity of 340 boxes.[1,2,3,4,5]

6. Trucks are used to transport muds/cuttings from barges to the landfill area.[2]

7. Transportation for a boat load of drilling waste to the temporary storage area will include 1 day boat trip from platform to onshore docking area including loading boxes on deck and 1 day unloading boxes and transportation to temporary storage area.[1]

8. Transportation from temporary storage to west side Cook Inlet landfill will include 1 day from storage area to docking facility and loading onto barges.[1]

9. Transportation of one barge load of waste from east side docking facility to west side landfill will include 1 day barge trip to west side unloading shore area and 1 day unloading boxes and transportation to the landfill.[1]

10. Onshore disposal cost (gate fee) is $14 per barrel.[6]

COST CALCULATIONS:

Total Disposal Cost of Drilling Wastes = Cost of Mud/Cuttings Boxes +
Cost of Temporary Onshore Storage +
Cost of Transportation +
Cost of Landfill

Cost of Muds/Cuttings Boxes

Total Volume of Drilling Waste from Worksheet 2 = 422,780 barrels, or 52,848 8-barrel boxes.

Assuming that boxes can be reused and allowing a maximum of 11 drillings in a given year (one per platform):

Total Number of Boxes Needed Per Well = 52,848 boxes/27 wells = 1,957 boxes per well where 27 is the number of wells planned for drilling for this operator;

Total Number of Boxes Needed = 1,957 boxes per well x 11 wells per year = 21, 527 boxes where 11 is the number of wells allowed to drill in a given year.

Total Cost of Muds/Cuttings Boxes = 21,527 boxes x $125 per box = $2,690,875

Cost of Temporary Onshore Storage

Space Occupied by Each Box = 4 feet x 4 feet = 16 square feet per box;

Total Accumulative Space Needed = 52,848 x 16 = 845,568 square feet;

Assuming a maximum storage time of 6 months and storage lease of $0.10 per square foot per month[2]:

Total Onshore Storage Cost = 845,568 x $0.10 x 6 = $507,340

Transportation Cost

SUPPLY BOAT COST:

Total Number of Days Supply Boats are Needed =

(52,848 boxes/227 box per boat) x (2 days) = 466 boat days;

Based on the cost of $3000 per day supply boat:

Total Cost of Supply Boats = 466 x 3000 = $1,398,000

TRUCKING COST:

Based on 1 day of unloading and travel from docking facility to temporary storage, 1 day travel from temporary storage to docking facility and loading, 1 day unloading and transport to the landfill facility, the truck capacity of 12 boxes per truck, and the trucking rate of $300 per day:

Total Cost of Trucking = (52,848/12) x $300 x 3 = $3,963,600

BARGE COST:

Based on the barge rental cost of $6,000 per day, 2 days of barge travel, and barge capacity of 340 boxes:

Total Cost of Barges = (52,848/340) x $6,000 x 2 = $1,865,223

Total Transportation Costs = $1,398,000 + $3,963,600 + $1,865,223 = $7,226,823

Landfill Disposal Costs

Based on the landfill disposal cost of $14 per barrel:

Total Landfill Cost = 422,780 barrels x $14 per barrel = $5,918,920

TOTAL LANDFILL DISPOSAL COST FOR OPERATOR B =

$2,690,875 + $507,340 + $7,226,823 + $5,918,920 = $16,343,958

TOTAL LANDFILL DISPOSAL COST PER BARREL OF WASTE =

$16,343,958/422,780 = $39 PER BARREL

List of References or Sources of Information

1. Wiedeman, A., U.S. EPA, "Report to Alaska - Cook Inlet and North Slope Oil and Gas Facilities," August 1993.

2. Correspondence from Operator B to SAIC, "Drill Cuttings and Fluids Discharge Additional Information." April 21, 1994. (CBI Files)

3. Safavi, B., SAIC, Contact Report with Ocean Marine Services, May 24, 1994.

4. Erickson, M., SAIC, Contact Report with Arctic Tug and Barge Company, March 16, 1994.

5. Safavi, B., SAIC, Contact Report with Arctic Tug and Barge Company, May 25, 1994.

6. Offshore Oil and Gas Industry: Analysis of the Costs and Pollutant Removals, EPA Contract No. 68-CO-004, WA # 2-01, January 13, 1994.

APPENDIX X-3

Drilling Waste Pollutant Reduction

Calculations

Worksheets 10 and 11

Worksheet No. 10, November 17, 1994, Page 1 of 3
Coastal Alaska Oil and Gas Drilling Industry
BAT Pollutant Loadings Analysis for Operators in Cook Inlet, Alaska
Cumulative Reduction in Pollutant Loadings
Zero Discharge Option

Total Volume of Drilling Waste Currently Discharged, barrels = (From Worksheet No. 2; Column 8)	552,846
Average Cuttings Percent of Total. % = (From Worksheet No. 1, Column 17)	19%
Total Volume of Cuttings Currently Discharged, barrels = (Total Volume) x (%Cuttings)	105,041
Average Density of Dry Cuttings, pounds per barrel = (From September 7, 1994 Supplemental Worksheet by SAIC)	980
Total Weight of Dry Cuttings Currently Discharged, pounds = (Average Density of Cuttings x Total Volume of Cuttings) This value is used as TSS associated with cuttings	102,939,925
Total Volume of Drilling Muds Currently Discharged, barrels = (Total Volume) x (1−%Cuttings) This value is used as the volumetric amount of muds discharged	447,805
Average Percent Dry Solids in Drilling Muds by Volume, % = (See June 6, 1994 Supplemental Worksheet)	11%
Total Volume of Dry Solids in Drilling Muds, barrels = (Percent Dry Solids x Total volume of Mud)	49,259
Average Density of Dry Solids in Drilling Muds, pounds per barrel = (See June 6, 1994 Supplemental Worksheet)	1025
Total Dry Weight of Muds Currently Discharged, pounds = (Average Density of Mud Solids x Total Volume of Mud Solids) This value is used as the dry−basis amount of muds discharged and the TSS associated with muds	50,490,043

Note: All volumes and weights are cumulative over 7 years from 1996 through 2002

Worksheet No. 10, November 17, 1994, Page 2 of 3
Coastal Alaska Oil and Gas Drilling Industry
BAT Pollutant Loadings Analysis for Operators in Cook Inlet, Alaska
Cumulative Reduction in Pollutant Loadings
Zero Discharge Option

(1) Pollutant Name	(2) Average Concentrations of Pollutants in Drilling Waste	(3) Total Amount of Drilling Waste Currently Discharged	(4) Total Cumulative Pollutant Loadings Based On Current Practices	(5) Percent Passing Zero Discharge Limitation (percent discharging)	(6) Total Cumulative Loadings Based on Zero Discharge	(7) Total Cumulative Reduction in Loadings Based on Zero Discharge
Conventional Pollutants			Pounds	% of total	Pounds	Pounds
TSS (Associated with Muds)			49,985,142.6	0%	0.0	49,985,142.6
TSS (Associated with Cuttings)			101,910,525.9	0%	0.0	101,910,525.9
TSS (Total)			**151,895,668.6**	**0%**	**0.0**	**151,895,668.6**
Total Oil	0.0596	447,805	26,422.3	0%	0.0	26,422.3
Total Conventional			**151,922,090.9**	**0%**	**0.0**	**151,922,090.9**
Priority Pollutants Organics	lbs/bbl of mud	Barrels	Pounds	% of total	Pounds	Pounds
Naphthalene	0.0000035	447,805	1.6	0%	0.0	1.6
Fluorene	0.0000563	447,805	25.0	0%	0.0	25.0
Phenenthrene	0.0000084	447,805	3.7	0%	0.0	3.7
Total Priority Pollutants Organics	**0.0000682**	**447805**	**30.2**	**0%**	**0.0**	**30.2**
Priority Pollutants Metals	lbs/lb dry mud	Pounds	Pounds	% of total	Pounds	Pounds
Cadmium	0.0000011	50,490,043	55.0	0%	0.0	55.0
Mercury	0.0000001	50,490,043	5.0	0%	0.0	5.0
Antimony	0.0000057	50,490,043	284.9	0%	0.0	284.9
Arsenic	0.0000071	50,490,043	354.9	0%	0.0	354.9
Beryllium	0.0000007	50,490,043	35.0	0%	0.0	35.0
Chromium	0.0002400	50,490,043	11,996.4	0%	0.0	11,996.4
Copper	0.0000187	50,490,043	934.7	0%	0.0	934.7
Lead	0.0000351	50,490,043	1,754.5	0%	0.0	1,754.5
Nickel	0.0000135	50,490,043	674.8	0%	0.0	674.8
Selenium	0.0000011	50,490,043	55.0	0%	0.0	55.0
Silver	0.0000007	50,490,043	35.0	0%	0.0	35.0
Thallium	0.0000012	50,490,043	60.0	0%	0.0	60.0
Zinc	0.0002005	50,490,043	10,022.0	0%	0.0	10,022.0
Total Priority Pollutants Metals	**0.0005255**	**50,490,043**	**26,267.2**	**0%**	**0.0**	**26,267.2**
Non-Conventional Pollutants	lbs/lb or bbl of mud	Pounds or Barrels	Pounds	% of total	Pounds	Pounds
Aluminum	0.0090699	50,490,043	453,360.2	0%	0.0	453,360.2
Barium	0.1200000	50,490,043	5,998,217.1	0%	0.0	5,998,217.1
Iron	0.0153443	50,490,043	766,987.0	0%	0.0	766,987.0
Tin	0.0000146	50,490,043	729.8	0%	0.0	729.8
Titanium	0.0000875	50,490,043	4,373.7	0%	0.0	4,373.7
Alkylated benzenes (a)	0.0021017	447,805	931.7	0%	0.0	931.7
Alkylated naphthalenes (b)	0.0000344	447,805	15.3	0%	0.0	15.3
Alkylated fluorenes (b)	0.0001218	447,805	54.0	0%	0.0	54.0
Alkylated phenanthrenes (b)	0.0000143	447,805	6.3	0%	0.0	6.3
Total biphenyls (b)	0.0001360	447,805	60.3	0%	0.0	60.3
Total dibenzothiophenes	0.0000004	447,805	0.2	0%	0.0	0.2
Total Non-Conventional Pollutants			**7224735.7**	**0%**	**0.0**	**7224735.7**
Total Reductions			**159,173,124.0**	**0%**	**0.0**	**159,173,124.0**

Worksheet No. 10, November 17, 1994, Page 3 of 3
Coastal Alaska Oil and Gas Drilling Industry
BAT Pollutant Loadings Analysis for Operators in Cook Inlet, Alaska
Cumulative Reduction in Pollutant Loadings
Zero Discharge Option

(1) Pollutant names include 14 heavy metals, 9 organic constituents, TSS, and Total Oil.
The listed pollutants of concern are as specified in Table VII–6 in the Coastal Development Document.

(2) Average concentration of the listed heavy metals were obtained from the Offshore DD (Table XI–6) except the value for Barium.
Concentration of Barium in the drilling mud was estimated based on the average mud weight (see SAIC, June 6, 1994).
Average concentrations of organic constituents were estimated based on the assumption that the primary source of these compounds in the mud is mineral oil.
Organic concentrations were estimated based on 0.02% mineral oil by volume (see SAIC, June 7, 1994, and Schmidt, July 11, 1994).
Average concentration of Total Oil was also estimated based on the use of 0.02% mineral oil (see June 7, 1994 Supplemental Worksheet).

(3) Amount of drilling waste currently discharged is given as total dry weight of muds (lbs) for metals and as total volume of drilling muds (barrels) for organics and oil.
These values are calculated on page 1 of this worksheet.

(4) Total cumulative pollutant loadings based on the current practice is the product of the average concentrations of pollutants in drilling muds (Column 2) and the total amount of muds generated (Column 3).
The calculations for the TSS pollutant loadings are shown on page 1.

(5) Percent passing zero discharge limitation is zero.

(6) Total cumulative loadings based on zero discharge is zero since no waste is discharged.

(7) Total cumulative reduction in loadings is equal to the loading under the current practices (Column 4) minus Zero Discharge loading (Column 6).

Worksheet No. 11, November 17, 1994, Page 1 of 3
Coastal Alaska Oil and Gas Drilling Industry
BAT Pollutant Loadings Analysis for Operators in Cook Inlet, Alaska
Cumulative Reduction in Pollutant Loadings
1,000,000 ppm SPP Toxicity Limitation Option

Total Volume of Drilling Waste Currently Discharged, barrels = (From Worksheets No. 2, Column 8)	552,846
Average Cuttings Percent of Total. % = (From Worksheet No. 1, Column 17)	19%
Total Volume of Cuttings Currently Discharged, barrels = (Total Volume) x (%Cuttings)	105,041
Average Density of Dry Cuttings, pounds per barrel = (From September 7, 1994 Supplemental Worksheet by SAIC)	980
Total Weight of Dry Cuttings Currently Discharged, pounds = (Average Density of Cuttings x Total Volume of Cuttings) This value is used as TSS associated with Cuttings	102,939,925
Total Volume of Drilling Muds Currently Discharged, barrels = (Total Volume) x (1 – %Cuttings) This value is used as the volumetric amount of muds discharged	447,805
Average Percent Dry Solids in Drilling Muds by Volume, % = (See June 6, 1994 Supplemental Worksheet)	11%
Total Volume of Dry Solids in Drilling Muds, barrels = (Percent Dry Solids x Total volume of Mud)	49,259
Average Density of Dry Solids in Drilling Muds, pounds per barrel = (See June 6, 1994 Supplemental Worksheet)	1025
Total Dry Weight of Muds Currently Discharged, pounds = (Average Density of Mud Solids x Total Volume of Mud Solids) This value is used as the dry–basis amount of muds discharged and the TSS associated with muds	50,490,043

Note: All volumes and weights are cumulative over 7 years from 1996 through 2002.

Worksheet No. 11, November 17, 1994, Page 2 of 3
Coastal Alaska Oil and Gas Drilling Industry
BAT Pollutant Loadings Analysis for Operators in Cook Inlet, Alaska
Cumulative Reduction in Pollutant Loadings
1,000,000 ppm SPP Toxicity Limitation Option

(1) Pollutant Name	(2) Average Concentrations of Pollutants in Drilling Waste	(3) Total Amount of Drilling Waste Currently Discharged	(4) Total Cumulative Pollutant Loadings Based on Current Practices	(5) Percent Passing Stringent Toxicity Limitation (percent discharging)	(6) Total Cumulative Loadings Based on Toxicity Limitation	(7) Total Cumulative Reduction in Loadings Based on Toxicity Limitation
Conventional Pollutants	**lbs/bbl of mud**	**Barrels**	**Pounds**	**% of total**	**Pounds**	**Pounds**
TSS (Associated with Muds)			49,985,142.6	83%	41,487,668.4	8,497,474.2
TSS (Associated with Cuttings)			101,910,525.9	83%	84,585,736.5	17,324,789.4
TSS (Total)			**151,895,668.6**	**83%**	**126,073,404.9**	**25,822,263.7**
Total Oil	0.0596	447,805	26,422.3	83%	0.0	26,422.3
Total Conventional Pollutants			**151,922,090.9**	**83%**	**126,073,404.9**	**25,848,686.0**
Priority Pollutants Organics	**lbs/bbl of mud**	**Barrels**	**Pounds**	**% of total**	**Pounds**	**Pounds**
Naphthalene	0.0000035	447,805	1.6	83%	0.0	1.6
Fluorene	0.0000563	447,805	25.0	83%	0.0	25.0
Phenenthrene	0.0000084	447,805	3.7	83%	0.0	3.7
Total Priority Pollutants Organics	**0.0000682**	**447,805**	**30.2**	**83%**	**0.0**	**30.2**
Priority Pollutants Metals	**lbs/lb dry mud**	**Pounds**	**Pounds**	**% of total**	**Pounds**	**Pounds**
Cadmium	0.0000011	50,490,043	55.0	83%	45.6	9.3
Mercury	0.0000001	50,490,043	5.0	83%	4.1	0.8
Antimony	0.0000057	50,490,043	284.9	83%	236.5	48.4
Arsenic	0.0000071	50,490,043	354.9	83%	294.6	60.3
Beryllium	0.0000007	50,490,043	35.0	83%	29.0	5.9
Chromium	0.0002400	50,490,043	11,996.4	83%	9,957.0	2,039.4
Copper	0.0000187	50,490,043	934.7	83%	775.8	158.9
Lead	0.0000351	50,490,043	1,754.5	83%	1,456.2	298.3
Nickel	0.0000135	50,490,043	674.8	83%	560.1	114.7
Selenium	0.0000011	50,490,043	55.0	83%	45.6	9.3
Silver	0.0000007	50,490,043	35.0	83%	29.0	5.9
Thallium	0.0000012	50,490,043	60.0	83%	49.8	10.2
Zinc	0.0002005	50,490,043	10,022.0	83%	8,318.3	1,703.7
Total Priority Pollutants Metals	**0.0005255**	**50,490,043**	**26,267.2**	**83%**	**21,801.8**	**4,465.4**
Non-Conventional Pollutants	**lbs/lb or bbl of mud**	**Pounds or Barrels**	**Pounds**	**% of total**	**Pounds**	**Pounds**
Aluminum	0.0090699	50,490,043	453,360.2	83%	376,289.0	77,071.2
Barium	0.1200000	50,490,043	5,998,217.1	83%	4,978,520.2	1,019,696.9
Iron	0.0153443	50,490,043	766,987.0	83%	636,599.2	130,387.8
Tin	0.0000146	50,490,043	729.8	83%	605.7	124.1
Titanium	0.0000875	50,490,043	4,373.7	83%	3,630.2	743.5
Alkylated benzenes (a)	0.0021017	447,805	931.7	83%	0.0	931.7
Alkylated naphthalenes (b)	0.0000344	447,805	15.3	83%	0.0	15.3
Alkylated fluorenes (b)	0.0001218	447,805	54.0	83%	0.0	54.0
Alkylated phenanthrenes (b)	0.0000143	447,805	6.3	83%	0.0	6.3
Total biphenyls (b)	0.0001360	447,805	60.3	83%	0.0	60.3
Total dibenzothiophenes	0.0000004	447,805	0.2	83%	0.0	0.2
Total Non-Conventional Pollutants			**7,224,735.7**	**83%**	**5,995,644.3**	**1,229,091.3**
Total Reductions		-	**159,173,124.0**	**83%**	**132,090,851.0**	**27,082,273.0**

Worksheet No. 11, November 17, 1994, Page 3 of 3
Coastal Alaska Oil and Gas Drilling Industry
BAT Pollutant Loadings Analysis for Operators in Cook Inlet, Alaska
Cumulative Reduction in Pollutant Loadings
1,000,000 ppm SPP Toxicity Limitation Option

(1) Pollutant names include 14 heavy metals, 9 organic constituents, TSS, and Total Oil.
The listed pollutants of concern are as specified in Table VII–6 in the Coastal Development Document.

(2) Average concentration of the listed heavy metals were obtained from the Offshore DD (Table XI–6) except the value for Barium.
Concentration of Barium in the drilling mud was estimated based on the average mud weight (see SAIC, June 6, 1994).
Average concentrations of organic constituents were estimated based on the assumption that the primary source of these compounds in the mud is mineral oil.
Organic concentrations were estimated based on 0.02% mineral oil by volume (see SAIC, June 7, 1994, and Schmidt, July 11, 1994)
Average concentration of Total Oil was also estimated based on the use of 0.02% mineral oil (see June 7, 1994 Supplemental Worksheet).

(3) Amount of drilling waste currently discharged is given as total dry weight of muds (lbs) for metals and as total volume of drilling muds (barrels) for organics and oil.
These values are calculated on page 1 of this worksheet.

(4) Total cumulative pollutant loadings based on the current practice is the product of the average concentrations of pollutants in drilling muds (Column 2) and the total amount of muds generated (Column 3).
The calculations for the TSS pollutant loadings are shown on page 1.

(5) Percent passing stringent toxicity limitation (83%) is obtained from "Preliminary Statistical Analysis of Permit Compliance Monitoring Records for the Toxicity of Drilling Fluids in Alaska," SAIC, September 30, 1994.

(6) Total cumulative loadings based on toxicity limitation is the product of the total loadings based on current practice (Column 4) and the percent passing the toxicity limitation.

(7) Total cumulative reduction in loadings is the difference between the loadings under the current practices (Column 4) and the loadings under the toxicity limitation (Column 6).

APPENDIX X-4

Cook Inlet Drilling Fluid

Toxicity Datasets

TABLE X – 4.1

EXCLUSIONS FROM COOK INLET DRILLING FLUID TOXICITY DATABASE (Source: SAIC, Sept. 30, 1994)

Permit Number	Operator Name	Well Name	Toxicity Date	Toxicity Value (ppm spp)	Reason For Exclusion
AKG285004	AMOCO	Anna, 32RD	09/25/87	0.00	Pill
AKG285004	AMOCO	Anna, 32RD	08/24/87	0.00	Too Little Mud
AKG285004	AMOCO	Anna, 32RD	09/26/87	26,000.00	Pill
AKG285004	AMOCO	Anna, 32RD	09/22/87	65,000.00	Pill
AKG285004	AMOCO	Anna, 32RD	--	Draft	Draft
AKG285008	ARCO	King Salmon, K6 RD	06/12/88	11,458.00	Pill
AKG285008	ARCO	King Salmon, K6 RD	06/14/88	32,038.00	Pill
AKG285008	ARCO	King Salmon, K6 RD	05/27/88	51,182.00	Pill
AKG285009	MARATHON	Dolly Varden, D–30RD #2	10/12/88	138,588.00	Pill
AKG285009	MARATHON	Dolly Varden, D–30RD #2	10/12/88	1,000,000.00	Pill
AKG285019	MARATHON	Steelhead, M–25	11/14/87	1,071.00	Pill
AKG285019	MARATHON	Steelhead, M–25	11/24/87	12,076.00	Pill
AKG285013	SWEPI	C, C21A–23	06/07/91	0.00	Pill
AKG285022	ARCO	Sunfish #1	08/27/91	11,473.00	Pill
AKG285015	UNOCAL	Granite Point, #51	09/04/92	293,334.00	Pill
AKG285016	UNOCAL	Grayling, G–1RD	02/04/92	30,000.00	Pill
AKG285016	UNOCAL	Grayling, G–1RD	02/14/92	30,789.00	Pill
AKG285015	UNOCAL	Granite Point, #32–13	04/24/92	256,700.00	Pill
AKG285011	PHILLIPS	Tyonek – Sunfish #2	12/21/93	1,000,000.00	Pill
AKG285011	PHILLIPS	Tyonek – Sunfish #2	06/26/93	50,960.00	Pill
AKG285011	PHILLIPS	Tyonek – Sunfish #2	06/24/93	422,200.00	Pill
AKG285006	UNOCAL	Bruce, 3–RD	02/22/94	91,390.00	Pill
AKG285006	UNOCAL	Bruce, 3–RD	02/06/94	23,724.00	Pill

TABLE X – 4.2

DRILLING FLUID TOXICITY DATABASE FOR COOK INLET (Source: SAIC, Sept. 30, 1994)

Permit Number	Operator Name	Well Name	Toxicity Value (ppm spp)	Toxicity Type	Toxicity Site	Toxicity Date 1	Toxicity Date 2	Base Mud	Pill Cite	BIOREQ	Drilling Fluid Discharged (bbl)
AKG285012	SWEPI	A, A23–01RD	1,000,000.00	Used/EOW	ABL 12/22/87 #871216–3	12/07/87		CI2		On Pill	0.00
AKG285004	AMOCO	Anna, 13RD	100,000.00	Used/EOW	ESE 4/88 #86–335	06/13/87	R	CI2			0.00
AKG285004	AMOCO	Anna, 32RD	48,000.00	Used	ESE 4/88 #86–335 (Mud 1)	08/10/87		CI2			0.00
AKG285004	AMOCO	Anna, 32RD	63,000.00	Used/EOW	ESE 4/88 #86–335 (Mud 6)	10/17/87		CI2			0.00
AKG285005	UNOCAL	Baker, #30	1,000,000.00	EOW	Analytikem 3/10/94, #02382 (ES–2136)	02/23/94		CI2	None		0.00
AKG285005	UNOCAL	Baker, B–29	1,000,000.00	EOW	Analytikem 2/2/94, #02271 (ES–2102)	01/20/94		CI2 PHPA	None		--
AKG285000	UNOCAL	Bruce G.P. 18742–20 RD	108,557.00	Used/EOW	Analytikem Q10116	03/31/91		CI2	None	EOW	3,350.00
AKG285006	UNOCAL	Bruce, 3–RD	279,483.50	NGM	Analytikem 1/26/94, #02259 (ES–2101)	01/17/94		KCl/XVIS	None		0.00
AKG285006	UNOCAL	Bruce, 42–2	39,330.30	NGM/EOW	Analytikem 11/14/93, #01965 (ES–2063)	10/25/93		KCl/XVIS	None		0.00
AKG285006	UNOCAL	Bruce, 42–2	239,359.00	EOW	Analytikem 11/14/93, #01964 (ES–2064)	09/27/93		CI2	None		0.00
AKG285006	AMOCO	Bruce, Granite Point 17587 #6	1,000,000.00	Used/EOW	WA/Core LAB #900204 2/90	01/23/90		CI2	None	EOW	0.00
AKG285013	SWEPI	C, C11–23	1,000,000.00	Used/EOW	ABL 5/23/91 #910515–1	05/12/91		CI2	None	EOW	12,148.00
AKG285013	SWEPI	C, C12–23	1,000,000.00	Used/NGM/EOW	ABL 5/29/90 900523–1	05/18/90		KCl2	None	EOW/NGM	0.00
AKG285013	SWEPI	C, C13–23	476,324.00	Used/EOW	ABL 10/14/88 #881007–1	--		CI2	None		0.00
AKG285013	SWEPI	C, C13A–23	1,000,000.00	Used/NGM	ABL 1/4/91 #901227–1	12/21/90		CI2	None	EOW	0.00
AKG285013	SWEPI	C, C21–23	457,943.00	Used/NGM	ABL 1/2/90 #891227–1	12/14/89		KCl2	None	Interim for NGM	0.00
AKG285013	SWEPI	C, C21–26	266,380.00	Used/EOW	ABL 5/30/89 #890519–1	--		CI2			0.00
AKG285013	SWEPI	C, C21A–23	320,000.00	Used/EOW	ABL 7/31/91 #910719–1	07/18/91		CI2	None	EOW	0.00
AKG285013	SWEPI	C, C22–23	156,190.00	Used/EOW	ABL 6/22/88 #880621–2	06/15/88		CI2	None	EOW	5,542.00
AKG285013	SWEPI	C, C24A–14	346,180.00	Used/EOW	ABL 3/21/88 #880321–2	03/18/88		CI2		On Pill	0.00
AKG285013	SWEPI	C, C24A–23	593,900.00	Used/EOW	ABL 9/2/88 #880825–1	08/25/88		CI2	None		0.00
AKG285013	SWEPI	C, C41–26	623,888.00	Used/EOW/NGM	ABL 9/19/89 #890913–1	09/10/89		KCl2	None	Interim for NGM	0.00
AKG285013	SWEPI	C, C41–26	1,000,000.00	Used/NGM	ABL 8/16/89 #890808–2	08/06/89		KCl2	None	Interim for NGM	0.00
AKG285013	SWEPI	C, C43–14	1,000,000.00	Used/EOW	ABL 2/89 #890208–1	--		CI2	None		0.00
AKG285009	MARATHON	Dolly Varden, D–30RD #2	885,382.00	Used/EOW	Weintritt, 033–12–7060	12/19/88		CI2	None	EOW	352.00
AKG285009	MARATHON	Dolly Varden, D–45	1,000,000.00	Used/EOW	ABL 7/3/89 #890627–1	06/27/89	T	CI2	None	EOW	10,927.00
AKG285009	MARATHON	Dolly Varden, D–46	1,000,000.00	Used/EOW	ABL 4/10/90 #900402–1	03/30/90		CI2	None	EOW	8,184.00
AKG285009	MARATHON	Dolly Varden, D–47RD	794,518.00	EOW	Analytikem 4/91, Q10128 (ES–1638)	04/17/91		NI	None		0.00
AKG285009	MARATHON	Dolly Varden, D–48	1,000,000.00	EOW	Analytikem 01427, 7/12/93	60/27/93		CI2	None		0.00
AKG285009	MARATHON	Dolly Varden, D7–RD2	61,732.90	EOW	Analytikem 01087, 4/5/93	03/29/93		NI	None		0.00
AKG285009	MARATHON	Dolly Varden, D7–RD2	377,354.40	Used	Analytikem 01064, 3/93	03/23/93		NI	None		0.00
AKG285015	UNOCAL	Granite Point, #11–13	2,120.00	EOW/ND	WA/Core 920252, 3/23/92	03/07/92		NI ?CI2	None		0.00
AKG285016	UNOCAL	Grayling, G–14RD	1,000,000.00	EOW	ABL 5/27/92 #920515–1	05/11/92		CI2	None		0.00
AKG285016	UNOCAL	Grayling, G–29RD	1,000,000.00	EOW	ABL 7/27/92 #920703–2	06/29/92		CI2	None		0.00
AKG285016	UNOCAL	Grayling, G–36DPN	546,967.00	Used/EOW	EHA 8/87 #870794	07/03/87		CI2	None	On Pill	0.00
AKG285016	UNOCAL	Grayling, G–40 RD	565,687.00	Used/EOW	WA/Core Lab #900657 2/90	03/15/90		CI2	None	EOW	0.00
AKG285008	UNOCAL	King Salmon, K–26	1,000,000.00	EOW	Analytikem 2/4/94, #02272 (ES–2105)	01/23/94		CI2	None		--
AKG285008	ARCO	King Salmon, K6 RD	2,704.00	Used/EOW	Weintritt, 033–12–6591	07/01/88		CI2	None	EOW	0.00
AKG285017	UNOCAL	Monopod, A–20 RD	805,025.00	Used/EOW	WA/Core Lab #900860 5/90	04/21/90		CI2	None	EOW	3,200.00
AKG285017	UNOCAL	Monopod, A–28 RD	573,326.00	Used/EOW	WA/Core Lab #900311 2/90	01/31/90		NI	None	EOW	0.00
AKG285017	UNOCAL	Monopod, A–8 RD	1,000,000.00	Used/EOW	Weintritt, 8/11/89	07/28/88		CI2	None	EOW	0.00
AKG285023	ARCO	North Forelands #1	362,600.00	EOW	Ambar #9004.92BA 9/15/92	09/03/92		CI2	None		0.00
AKG285019	MARATHON	Steelhead M–19	1,000,000.00	EOW	Analytikem 10/22/93, #01867 (ES–2053)	10/05/93		CI2	None		0.00
AKG285019	MARATHON	Steelhead M–1	52,800.00	Used/EOW/NGM	ABL 7/17/87 #870708–4	06/29/87		Poly Plus K		On Mud, Add, Pill	0.00
AKG285019	MARATHON	Steelhead M–1	64,500.00	Used/NGM	ABL 7/17/87 #870708–6	06/22/87		Poly Plus K		On Mud, Add, Pill	0.00
AKG285019	MARATHON	Steelhead M–1	109,000.00	Used/EOW/NGM	ABL 7/17/87 #870708–5	07/15/87		Poly Plus K		On Mud, Add, Pill	0.00
AKG285019	MARATHON	Steelhead M–13	1,000,000.00	Used/EOW/NGM	ENSR Sample EN89326	10/02/89		Poly Plus G	None	EOW	6,215.00
AKG285019	MARATHON	Steelhead M–14	1,000,000.00	Used/EOW/NGM	ENSR Sample EN89423	12/11/89		Poly Plus G	None	EOW	6,604.00
AKG285019	MARATHON	Steelhead M–15	1,000,000.00	Used/EOW/NGM	ABL 10/29/90 #901023–1	10/16/90		Poly Plus G	None	EOW	6,598.00
AKG285019	MARATHON	Steelhead M–2	197,928.00	Used/NGM	EHA/MI 9/21/87 #82687–1	08/26/87		Poly Plus K		On Mud, Add, Pill	0.00
AKG285019	MARATHON	Steelhead M–25	280,267.00	Used/Pill/NGM	EHA/MI 12/9/87 #ES–1142	11/11/87		Poly Plus K	(a)	On Mud, Add, Pill	0.00
AKG285019	MARATHON	Steelhead M–26 Relief	1,000,000.00	Used/EOW	EHA 8/88 #880544	07/22/88		CI2	None	EOW	4,883.00
AKG285019	MARATHON	Steelhead M–27	1,000,000.00	Used/EOW	Analytikem #ES–1605	01/26/91		CI2	No Pill (b)	EOW	15,741.00
AKG285019	MARATHON	Steelhead M–28	5,082.00	Used/EOW	ENSR Sample EN90262	05/29/90		CI2	None (c)	EOW	7,152.00
AKG285019	MARATHON	Steelhead M–29	1,000,000.00	Used/EOW	Analytikem #ES–1672	06/24/91		CI2	None	EOW	0.00
AKG285019	MARATHON	Steelhead M–29	1,000,000.00	EOW	Analytikem Q10220, 7/91	06/24/91		?CI2	None		0.00
AKG285019	MARATHON	Steelhead M–3	1,000,000.00	Used/EOW	ABL 8/10/90 #900803–3	07/29/90		CI2	None	EOW	2,568.00
AKG285019	MARATHON	Steelhead M–30	1,000,000.00	EOW	Analytikem 00333, 6/24/93	06/16/92		?CI2	None		0.00
AKG285019	MARATHON	Steelhead M–5	1,000,000.00	Used/EOW	ENSR Sample EN90121	02/28/90		CI2 W/PHPA	None	EOW	3,148.00
AKG285021	ARCO	Sturgeon #1	1,000,000.00	Used/EOW	WA/Core Lab #902101 10/90	10/07/90		CI2	None	EOW	11,749.00
AKG285011	PHILLIPS	Tyonek–Sunfish #2	278,600.00	NGM/EOW	Seacrest 10083–93–004, 9/23/93	08/21/93		KCl	None		0.00
AKG285011	PHILLIPS	Tyonek–Sunfish #3	976,000.00	EOW	Lab Tech #PP001, 3/28/94	03/08/94		CI2	None		0.00

Note:

(a) Mud prior to kwikspot use.

(b) Bit Lube II had been used during interval.

(c) Mud cut by producing formation.

APPENDIX X-5

Cook Inlet Drilling Fluids

BCT (Version 2)

Costs Tests

BCT Costs – Version 2

Printed: 09-Nov-94

Assumptions:		Source
1) Cuttings Density =	980.00 lb/bbl	SAIC, Sept. 7, 1994
2) TSS in Muds =	113.00 lb/bbl	SAIC, Aug. 18, 1994
3) Oil Density =	297.74 lb/bbl	Offshore Development Document
4) Oil in Muds =	2.00%	SAIC, Aug. 18, 1994
5) Min. Oil Subst. Cost =	84.00 $/bbl	Offshore Development Document
6) M&C Disposal Cost (Option 2) =	76.00 $/bbl	SAIC, Oct. 14, 1994
7) M&C Disposal Cost (Option 3) =	42.00 $/bbl	SAIC, Aug. 30, 1994
8) Total Vol. M&C Disposed (Option 2) =	2,093 bbl/well	Based on 17% failure rate (0-10,000 ft)
9) Total Vol. M&C (Option 3) =	12,313 bbl/well	Based on the first 10,000 ft

Min. oil subst. cost (BCT Option 2): 16,756 $/well (based on first 10,000 ft)
Cutt. Disposal Cost (BCT Option 2): 30,226 $/well (based on first 10,000 ft)
Muds Disposal Cost (BCT Option 2): 128,858 $/well (based on first 10,000 ft)

Conventional Pollutants Removed under BCT Option 2 (above 10,000 ft)

	Muds (lb/well)	Cuttings (lb/well)	Total (lb/yr)
TSS	191,592	389,756	581,348
Oil	10,096	0	10,096
Total	201,688	389,756	591,444

BCT Cost Tests for Optinos 2

	Increm. Conv. Poll. (lb/well)	Increm. Disp. Cost ($/well)	POTW Cost ($/lb)	Pass POTW	ICR	Pass ICR
Muds	201,688	145,614	0.722	no	8.494	no
Cuttings	389,756	30,226	0.078	yes	1.368	no
Total M&C	591,444	175,840	0.297	yes	4.125	no

Min. oil subst. cost (BCT Option 3): 0 $
Cutt. Disposal Cost (BCT Option 3): 98,258 $/well (based on first 10,000 ft)
Muds Disposal Cost (BCT Option 3): 418,888 $/well (based on first 10,000 ft)

Conventional Pollutants Removed under BCT Option 3 (above 10,000 ft)

	Muds (lb/well)	Cuttings (lb/well)	Total (lb/well)
TSS	1,127,009	2,292,681	3,419,690
Oil	59,390	0	59,390
Total	1,186,399	2,292,681	3,479,080

BCT Cost Tests for Option 3

	Increm. Conv. Poll. (lb/well)	Increm. Disp. Cost ($/well)	POTW Cost ($/lb)	Pass POTW	ICR	Pass ICR
Muds	1,186,399	418,888	0.353	yes	4.153	no
Cuttings	2,292,681	98,258	0.043	yes	0.754	yes
Total M&C	3,479,080	517,146	0.149	yes	2.069	no

APPENDIX XI-1

Calculations for Cost of Produced Water

Disposal By Barge and Truck

I. Calculations for Total Cost of Produced Water Disposal by Barge

Given Data:

Barge and tug rental cost = $1,500/day (SAIC, January 27, 1995)

Commercial Facility Disposal Cost = $0.50/bbl (SAIC, January 27, 1995)

Loading time for 3,000 bbl = 8 hrs (SAIC, January 27, 1995)

Unloading time for 3,000 bbl = 8 hrs (SAIC, January 27, 1995)

Time to dock at platform = 1 hr (Sunda, March 10, 1994)

Traveling speed for barge and tug = 6 mi/hr (SAIC, January 27, 1995)

Distance to disposal facility = 50 mi (Sunda, March 10, 1994)

Distance from port to first platform = 50 mi (Sunda, March 10, 1994)

Distance between each facility is 10 miles (Sunda, March 10, 1994)

Calculations:

Case 1: The barge services 20 facilities each with 150 bbl storage tanks

Distance traveled = [10 x (20-1)] + (2 x 50) = 290 mi

Total time of operations = (290 mi)/(6 mi/hr) + 8(hrs) + 8(hrs) + 20 x 1(hr) = 84 hrs

Transportation cost = (84 hrs)/(24 hr/day) x (1,500 $/day)/(3,000 bbl/barge) = $1.75/bbl

Total disposal cost = 1.75 + 0.50 = $2.25/bbl

Case 2: The barge services 10 facilities each with 300 bbl storage tanks

Distance traveled = [10 x (10-1)] + (2 x 50) = 190 mi

Total time of operations = (190 mi)/(6 mi/hr) + 8(hrs) + 8(hrs) + 10 x 1(hr) = 58 hrs

Transportation cost = (58 hrs)/(24 hr/day) x (1,500 $/day)/(3,000 bbl/barge) = $1.21/bbl

Total disposal cost = 1.21 + 0.50 = $1.71/bbl

Case 3: The barge services 3 facilities each with 1000 bbl storage tanks

Distance traveled = [10 x (3-1)] + (2 x 50) = 120 mi

Total time of operations = (120 mi)/(6 mi/hr) + 8(hrs) + 8(hrs) + 3 x 1(hr) = 39 hrs

Transportation cost = (39 hrs)/(24 hr/day) x (1,500 $/day)/(3,000 bbl/barge) = $0.81/bbl

Total disposal cost = 0.81 + 0.50 = $1.31/bbl

Case 4: The barge services 2 facilities each with 1500 bbl storage tanks

Distance traveled = [10 x (2-1)] + (2 x 50) = 110 mi

Total time of operations = (110 mi)/(6 mi/hr) + 8 + 8 + 2 x 1(hr) = 36 hrs

Transportation cost = (36 hrs)/(24 hr/day) x (1,500 $/day)/(3,000 bbl/barge) = $0.75/bbl

Total disposal cost = 0.75 + 0.50 = $1.25/bbl

Number Facilities	Distance Traveled	Total Disposal Cost
20	290 mi	$2.25/bbl
10	190 mi	$1.71/bbl
3	120 mi	$1.31/bbl
2	110 mi	$1.25/bbl

Average Unit Disposal Cost = $1.63/bbl

II. Calculations for Transportation Cost of Produced Water by Truck

Given Data:

Average Total Disposal Cost = $1.66/bbl (SAIC, January 27, 1995)

Truck plus Driver Rental Cost = $55/hr (Sunda, Feb. 18, 1993)

Commercial Facility Disposal Cost = $0.50/bbl

Loading plus Unloading Time = 0.5 hrs (Sunda, Feb. 18, 1993)

Average Travel Speed = 55 mph (assumed speed limit)

Truck plus Driver Rental Cost = $50/hr (Wiedeman, June 30, 1992)

Truck Capacity = 5,000 gal (119 bbl)

Calculations:

Case 1: Travel distance at $55/hr rental cost

Rental Time = (1.16 $/bbl) x (119 bbl/truck)/($55/hr/truck) = 2.5 hrs

Travel Time = 2.5 hrs - 0.5 hrs (loading/unloading) = 2.0 hrs

Travel Distance = 2 hrs x 55 mi/hr = 110 mi

Case 2: Travel distance at $50/hr rental cost

Rental Time = (1.16 $/bbl) x (119 bbl/truck)/($50/hr/truck) = 2.8 hrs

Travel Time = 2.8 hrs - 0.5 hrs (loading/unloading) = 2.3 hrs

Travel Distance = 2.3 hrs x 55 mi/hr = 127 mi

Average Travel Distance = $\frac{127 + 110}{2}$ = 120 mi (roundtrip)

APPENDIX XI-2

Calculations For Cost of Centralized Injection Systems

Company: BKN Oil and Gas, Inc.

Field: Matagorda Bay, Texas

Non-Centralized Costs:

	Flow (bpd)		Pipe Diam. (in)	Individual Capital Cost ($)	Individual O&M Cost ($/yr)
	Current	Future			
	775	1,162.5	3	175,205	40,067
	375	562.5	3	161,901	30,182
	1,200	1,800	3	189,340	50,570
	86	129	3	152,289	23,040
Total:	2,436	3,654	--	678,735	143,859

Piping Distance: 1.17 mi (the longest distance in this field was 2.34 mi)

Piping Cost: 4 x (3 inch dia.) x (1.17 mi) x (5,280 ft/mi) x (4.06/in-dia./linear ft.) = $300,973

Comparison:

Centralized Cap. Cost = $230,448 + $300,973 = $531,421

Centralized O&M Cost = $81,115/yr

- These capital and O&M costs were calculated using the total furture flow in the table above and the equations for "single-well injection systems" in Table XI-6 for land-access facilties.

Annualization Analysis:

Centralized Costs = ($531,421 x 0.1627) + $81,115/yr = $167,577/yr

Individual Costs = ($678,735 x 0.1627) + $143,859/yr = $254,289/yr

Result: Centralize

NOTE:

There are 11 operators for which centralized injection systems are more economical than individual injection systems. (see Appendix XI-3)

APPENDIX XI-3

Capital and O&M Costs

for Discharging Facilities

in the Gulf of Mexico

LOUISIANA MEDIUM/LARGE–VOLUME FACILITIES – ZERO DISCHARGE

Printed: 22–Sept–94

Permit–Outfall Number	Operator	Current Avg. Vol (bpd)	Future Avg. Volume (bpd)	O&M Cost ($/yr)	Cap. Cost ($)	Piping Cost ($)	Total Cap. Cost ($)
3040–001	Alliance Operating Corp.	1,678.0	2,517.0	60,921	399,400	0	399,400
3650–001	Alltex Exploration, Inc.	465.0	697.5	30,908	347,093	0	347,093
3408–001	Amerada Hess Corp.	3,662.0	5,493.0	107,941	526,094	0	526,094
2184–001	Ashlawn Energy, Inc.	3,142.7	4,714.1	97,162	462,560	0	462,560
2184–002	Ashlawn Energy, Inc.	3,142.7	4,714.1	97,162	462,560	0	462,560
2184–003	Ashlawn Energy, Inc.	3,142.7	4,714.1	97,162	462,560	0	462,560
3795–001	Atlas Production Services, Inc.	151.5	227.3	23,151	333,574	0	333,574
3795–002	Atlas Production Services, Inc.	151.5	227.3	23,151	333,574	0	333,574
3686–001	Bois d'Arc Operating Corp.	925.0	1,387.5	42,290	366,929	0	366,929
3870–001	Bois d'Arc Operating Corp.	1,010.0	1,515.0	44,393	370,595	0	370,595
3086–001	Burk Royalty Co.	450	675.0	30,537	346,446	0	346,446
1901–001	Callon Offshore Production, Inc.	30,200.0	45,300.0	805,857	3,506,909	0	3,506,909
1901–002	Callon Offshore Production, Inc.	30,200.0	45,300.0	805,857	3,506,909	0	3,506,909
1934–001–1	Callon Offshore Production, Inc.	14,443.0	21,664.5	391,468	1,737,044	0	1,737,044
2142–001–1	Callon Offshore Production, Inc.	12,076.0	18,114.0	329,219	1,471,176	0	1,471,176
2672–001–2	Callon Offshore Production, Inc.	9,175.0	13,762.5	252,926	1,145,329	0	1,145,329
2859–001	Callon Offshore Production, Inc.	11,290.0	16,935.0	308,548	1,382,891	0	1,382,891
2860–003	Callon Offshore Production, Inc.	7,120.0	10,680.0	198,882	914,506	0	914,506
1857–001 to 011	Chevron U.S.A., Inc.	18,659.7	27,989.6	502,362	2,210,674	1,522,227	3,732,901
1861–001	Chevron U.S.A., Inc.	4,600.0	6,900.0	132,609	631,453	0	631,453
1863	Chevron U.S.A., Inc.	27,856.0	41,784.0	744,213	3,243,625	0	3,243,625
1896	Chevron U.S.A., Inc.	35,652.0	53,478.0	949,238	4,119,292	0	4,119,292
3853–001	Cliffs Oil & Gas Co.	245.0	367.5	25,465	337,606	0	337,606
3038–001	CXY Energy, Inc.	500.0	750.0	31,774	348,602	0	348,602
3067–000	Denovo Oil and Gas, Inc.	200.0	300.0	24,351	335,666	0	335,666
2185–001	Energy Development Corp.	700.0	1,050.0	36,723	357,227	0	357,227
2785–001	Energy Development Corp.	250.0	375.0	25,588	337,822	0	337,822
2779–001	Graham Royalty, Ltd.	950.0	1,425.0	42,908	368,007	0	368,007
4029–001	Hilcorp Energy Co.	3,522.0	5,283.0	104,259	510,369	0	510,369
4467–001	Houma Production Co.	400.0	600.0	29,300	344,290	0	344,290
2368–001 to 006	Hunt Petroleum Co.	5,625.0	8,437.5	159,566	746,584	1,205,820	1,952,404
3008–001	Hunt Petroleum Co.	266.0	399.0	25,984	338,512	0	338,512
3029–001	James A. Whitson, Jr.	300.0	450.0	26,826	339,978	0	339,978
3081–001	Konantz, Inc.	613.0	919.5	34,570	353,475	0	353,475
2710–001	Linder Oil Co.	904.0	1,356.0	41,770	366,024	0	366,024
1853–001	LLECO Holdings, Inc.	324.0	486.0	27,419	341,013	0	341,013
3746–001	Marblehead Energy Corp.	1,250.0	1,875.0	50,331	380,944	0	380,944
2164–001–1	Oryx Energy Co.	150.0	225.0	23,114	333,510	0	333,510
3223–001	Pel–Tex Oil Co.	186.0	279.0	24,005	335,062	0	335,062

LOUISIANA MEDIUM/LARGE-VOLUME FACILITIES - ZERO DISCHARGE

Printed: 22-Sept-94

Permit-Outfall Number	Operator	Current Avg. Vol (bpd)	Future Avg. Volume (bpd)	O&M Cost ($/yr)	Cap. Cost ($)	Piping Cost ($)	Total Cap. Cost ($)
3407-001	Pennzoil Exploration & Production Co.	6,300.0	9,450.0	177,317	822,401	0	822,401
2838-001	Petro Corp.	1,500.0	2,250.0	56,517	391,724	0	391,724
2227-001	Quintana Petroleum Corp.	600.0	900.0	34,248	352,915	0	352,915
2071	Shell	144,000.0	216,000.0	4,305,586	15,148,713	0	15,148,713
2084-001	Texaco, Inc.	1,715.6	2,573.4	61,852	401,021	0	401,021
2084-003-1	Texaco, Inc.	1,715.6	2,573.4	61,852	401,021	0	401,021
2084-005	Texaco, Inc.	1,715.6	2,573.4	61,852	401,021	0	401,021
2084-012	Texaco, Inc.	1,715.6	2,573.4	61,852	401,021	0	401,021
2084-015	Texaco, Inc.	1,715.6	2,573.4	61,852	401,021	0	401,021
2084-016	Texaco, Inc.	1,715.6	2,573.4	61,852	401,021	0	401,021
2816-011	Texaco, Inc.	291.1	436.7	26,605	339,594	0	339,594
2825-001 to 003	Texaco, Inc.	1,998.9	2,998.4	68,861	413,238	760,149	1,173,387
2882-001/002	Texaco, Inc.	1,494.0	2,241.0	56,368	391,465	0	391,465
2970-001	Texaco, Inc.	500.0	750.0	31,774	348,602	0	348,602
2971-001	Texaco, Inc.	2,650.0	3,975.0	84,971	441,314	0	441,314
2971-002	Texaco, Inc.	2,650.0	3,975.0	84,971	441,314	0	441,314
3032-001	Texoil Co.	939.0	1,408.5	42,636	367,533	0	367,533
2547-001	Torch Operating Co.	109.0	163.5	22,100	331,742	0	331,742
2708-001	Torch Operating Co.	278.0	417.0	26,281	339,029	0	339,029
1950-001	Warren Petroleum Co.	1,680.0	2,520.0	60,971	399,486	0	399,486
3039-001	Wichita River Oil Corp.	270.0	405.0	26,083	338,684	0	338,684
2909-001	WRT Energy Corp.	3,252.0	4,878.0	99,866	467,274	0	467,274
2118-001 to 003	W.W.F. Oil Corp	1,110.0	1,665.0	46,867	374,907	216,083	590,990
		415,493		12,433,046			62,576,229

LOUISIANA SMALL–VOLUME FACILITIES – ZERO DISCHARGE

Printed: 06–June–94

Operator	Permit–Outfall Number	Field	Facility	Current Vol (BPD)	Capital Cost ($)	O&M Cost ($/yr)
BKE–A, LLC	2858–001	Chandeleur Sound Blk 63	Chandeleur Sound Blk 63 Platform	1	32,010	595
Carl Oil & Gas Co.	2699–001	Three Bayou Bay		30	40,607	17,849
Cashco Oil Co.	3074–001	Eugene Island Blk 1	Eugene Island Prod. Platform	72	83,471	42,836
Claron Corp.	2945–001	Diamond	Oil and Gas Production	15	32,010	8,924
Desco Oil Co.	3459–000	Bayou Jean La Croix	Terrebonne Parish	34	40,607	20,228
DKM Resources, Inc.	3133–001	Stuard's Bluff	S.L. 4904	22	40,607	13,089
Hunt Petroleum Co.	2704–001	Caillou Island	Caillou Is. Fac S.L. 2857	75	83,471	44,621
Japex (U.S.) Corp.	2956–000	Bayou Herbert		13	32,010	7,734
Linder Oil Co	2408–001	Black Bay	Lejeune #1	20	32,010	11,899
Quintana Petroleum Corp.	2299–001	Bayou Fer Blanc	Bayou Fer Blanc TB	2	32,010	1,190
Samedan Oil Corp.	2626–001	Buck Point (N)	N Buck Point Fac	100	83,471	59,495
Whiting Petroleum Co.	2138–002/001	Leeville	Constantine #2	42	40,607	24,988
				426	572,891	253,449

TEXAS MEDIUM/LARGE–VOLUME FACILITIES – ZERO DISCHARGE Printed: 01–Jun–94

Permit No.	Texas Operator	Current Volume (BPD)	Future Volume (BPD)	O&M Cost ($/yr)	Cap. Cost ($)	Piping Cost ($)	Total Cap. Cost ($)
163	ACE PRODUCTIONS	450	675	32,036	164,395	0	164,395
136	AMERICAN EXPLORATION CO	4,476	6,714	130,303	338,073	0	338,073
666	AMERICAN EXPLORATION CO	335	503	29,194	160,571	0	160,571
19	APACHE CORP	1,685	2,528	62,556	205,471	453,388	658,859
590	BKN OIL & GAS, INC	2,436	3,654	81,115	230,448	300,973	531,421
684	BRANDES PETROLEUM INC	250	375	27,093	157,744	0	157,744
105	BROWN, CLIFFORD L, JR	2,370	3,555	79,484	228,253	632,814	861,068
90,113	BROWN, GEORGE R. PRTNRSHP	6,670	10,005	188,614	474,862	141,054	615,916
693	BRYMER CONTRACTING CO	436	654	31,690	163,930	0	163,930
673	BWS VACUUM SERVICE, INC.	130	195	24,127	153,752	0	153,752
60	CEDAR POINT OIL CO	1,200	1,800	50,570	189,340	0	189,340
675	CHAIN OIL & GAS, INC	210	315	26,104	156,413	0	156,413
857	CLARON CORP	175	263	25,239	155,249	0	155,249
904	COASTAL OIL & GAS CORP	4,839	7,259	139,950	360,705	0	360,705
905	COASTAL OIL & GAS CORP	74	111	22,743	151,890	0	151,890
616	CREST RESOURCES & EXPLOR	400	600	30,800	162,732	0	162,732
694	CREST RESOURCES & EXPLOR	180	270	25,363	155,415	0	155,415
710	DAN J HARRISON III&FH BRUCE	150	225	24,622	154,418	0	154,418
637	DENOVO OIL & GAS, INC	652	978	37,028	171,114	0	171,114
241	DEWBRE PETROLEUM CORP	155	233	24,745	154,584	0	154,584
649	DYNAMIC PRODUCTION, INC.	80	120	22,892	152,090	0	152,090
13	ENSENJAY PETROLEUM CORP	1,193	1,790	50,397	189,107	0	189,107
80	EXXON CORP	1,948	2,922	69,056	214,218	0	214,218
81	EXXON CO, USA	888	1,332	42,860	178,963	0	178,963
26	EXXON CORP – HOUSTON	7,495	11,243	210,540	526,298	0	526,298
202	FORT WORTH OIL AND GAS	84	126	22,991	152,223	0	152,223
89	GOODRICH OPERATING CO, INC	137	206	24,300	153,985	0	153,985
739	GRAHAM ROYALTY, LTD	330	495	29,070	160,404	0	160,404
635	GULF VACUUM SERVICE	1,290	1,935	52,794	192,333	0	192,333
627	HAPS OIL & GAS CORP	185	278	25,487	155,582	0	155,582
134	HEADINGTON OIL CO	400	600	30,800	162,732	0	162,732
885	HOUSTON OIL & MINERALS CORP	168	252	25,067	155,016	0	155,016
632	KANSAS OIL & GAS CO	904	1,356	43,255	179,495	0	179,495
152	KEPLINGER OPERATING CO	80	120	22,892	152,090	0	152,090
249	KILLAM OIL CO	3,755	5,633	111,140	293,121	0	293,121

TEXAS MEDIUM/LARGE–VOLUME FACILITIES – ZERO DISCHARGE

Printed: 01–Jun–94

Permit No.	Texas Operator	Current Volume (BPD)	Future Volume (BPD)	O&M Cost ($/yr)	Cap. Cost ($)	Piping Cost ($)	Total Cap. Cost ($)
122	KILMARNOCK OIL CO	200	300	25,857	156,081	0	156,081
672	KING OIL	120	180	23,880	153,420	0	153,420
587	LINDA PRODUCTION, INC	80	120	22,892	152,090	0	152,090
264	LIVE OAK RESERVES, INC	775	1,163	40,067	175,205	0	175,205
659	LONE OAK DISPOSAL CO	248	372	27,044	157,677	0	157,677
580	LUNDY VACUUM SERVICE, INC	100	150	23,386	152,755	0	152,755
207	MIRESCO, INC	1,033	1,550	46,443	183,786	0	183,786
1	NEUMIN PRODUCTION CO	88	132	23,089	152,356	0	152,356
68	ORANGE PETROLEUM CO	5,759	8,639	164,401	418,064	421,876	839,941
577	PATON OIL CORP	682	1,023	37,769	172,112	0	172,112
789	PAX PETROLEUM CORP	350	525	29,564	161,070	0	161,070
276	PEARL, BILL H. PROD, INC	375	563	30,182	161,901	0	161,901
166	PETRO VEST, INC	100	150	23,386	152,755	0	152,755
167	PETRO VEST, INC	400	600	30,800	162,732	0	162,732
242	PI ENERGY, INC	600	900	35,743	169,384	0	169,384
4CCC	PI ENERGY, INC	75	113	22,768	151,923	0	151,923
595	POYNOR CORP	72	108	22,694	151,823	0	151,823
822	POYNOR CORP	1,000	1,500	45,628	182,688	0	182,688
282	REDFISH BAY OPERATING CORP	110	165	23,633	153,087	0	153,087
613	REDFISH BAY OPERATING CORP	600	900	35,743	169,384	0	169,384
744	SCANA EXPLORATION CO	1,200	1,800	50,570	189,340	0	189,340
127,132	SHELTON, CHARLES, H	574	861	35,100	168,520	270,104	438,623
685	SNR OILFIELD SERVICES, INC	600	900	35,743	169,384	0	169,384
124	S&S ENERGY, INC	783	1,175	40,265	175,471	241,164	416,635
674	TD OPERATING CO	200	300	25,857	156,081	0	156,081
20	TEXACO E & P INC	275	413	27,711	158,575	0	158,575
85	TEXACO E & P INC	112	168	23,683	153,154	0	153,154
155	TEXACO E & P, INC	1,660	2,490	61,938	204,639	0	204,639
156	TEXACO E & P, INC	2,746	4,119	88,776	240,759	0	240,759
157	TEXACO E & P, INC	479	719	32,752	165,360	0	165,360
854	TEXANA OPERATING CO	185	278	25,487	155,582	0	155,582
177	TEXAS PETROLEUM CO	1,500	2,250	57,984	199,318	0	199,318
189	TIERRA MINERAL DEVELOPMENT	2,045	3,068	71,453	217,444	0	217,444
165	UNION OIL CO OF CA	144	216	24,473	154,218	0	154,218
47	UNITED TEXAS CORP (A)	150	225	24,622	154,418	0	154,418

TEXAS MEDIUM/LARGE–VOLUME FACILITIES – ZERO DISCHARGE

Printed: 01–Jun–94

Permit No.	Texas Operator	Current Volume (BPD)	Future Volume (BPD)	O&M Cost ($/yr)	Cap. Cost ($)	Piping Cost ($)	Total Cap. Cost ($)
605	WHITTINGTON OPERATING CO	245	368	26,969	157,577	0	157,577
680	ZILKA ENERGY CO	110	165	23,633	153,087	0	153,087
219	ZINN PETROLEUM CO	300	450	28,329	159,407	0	159,407
	Total:	72,285		3,317,232			16,191,018

TEXAS SMALL–VOLUME FACILITIES – ZERO DISCHARGE

Printed: 27–May–94

Permit No.	Operator	County	Current Volume (BPD)	Cap. Cost ($)	O&M Cost ($/yr
663	AMOCO PRODUCTION CO	BRAZORIA	15	28,510	9,089
655	BAY OPERATING CO, INC.	NUECES	15	28,510	9,089
590	BKN OIL & GAS, INC	MATAGORDA	43	28,510	26,054
590	BKN OIL & GAS, INC	MATAGORDA	50	28,510	30,295
590	BKN OIL & GAS, INC	MATAGORDA	40	28,510	24,236
590	BKN OIL & GAS, INC	MATAGORDA	35	28,510	21,207
590	BKN OIL & GAS, INC	MATAGORDA	13	28,510	7,877
590	BKN OIL & GAS, INC	MATAGORDA	32	28,510	19,389
590	BKN OIL & GAS, INC	MATAGORDA	68	28,510	41,201
195	BRISTOL RESOURCES CORP	NUECES	16	28,510	9,694
197	BRISTOL RESOURCES CORP	NUECES	32	28,510	19,389
105	BROWN CLIFFORD L, JR	ORANGE	25	28,510	15,148
214	BROWN, GEORGE R PRTRSHP	NUECES	22	28,510	13,330
747	CAVALLA ENERGY EXPLORATION CO	CALHOUN	43	28,510	26,054
64	COASTAL OIL & GAS CORP	HARRIS	40	28,510	24,236
628	CONVEST ENERGY CORP	ARANSAS	15	28,510	9,089
792	CORPUS CHRISTI LEASEHOLDS, INC	NUECES	4	28,510	2,424
723	CORPUS CHRISTI OIL & GAS CO	CALHOUN	15	28,510	9,089
708	CORPUS CHRISTI OIL & GAS CO	CALHOUN	8	28,510	4,847
104	EBB TIDE OIL CO	HARRIS	55	28,510	33,325
71	EBB TIDE OIL CO	HARRIS	4	28,510	2,424
752	HOUSTON OIL PROD ENT, INC	ORANGE	10	28,510	6,059
753	HOUSTON OIL PROD ENT, INC	GALVESTON	29	28,510	17,571
102	KARBUHN OIL CO	JEFFERSON	46	28,510	27,871
184	LA PARRITA OIL & GAS, INC	KLEBERG	12	28,510	7,271
582	LAMAR OIL & GAS, INC	KENEDY	70	28,510	42,413
111	MARSHALL PETROLEUM, INC	HARRIS	10	28,510	6,059
238	MERRICO RESOURCES, INC	NUECES	34	28,510	20,601
206	MIDCON OFFSHORE, INC	NUECES	10	28,510	6,059
119	M.K. MCDANIEL	HARRIS	44	28,510	26,660
645	OIL LEASE OPERATING CO	CHAMBERS	10	28,510	6,059
14	PI ENERGY, INC	CALHOUN	20	28,510	12,118
638	PINELL, H P TRUSTEE	WILLACY	24	28,510	14,542
176	S.S.C. GAS PRODUCING CO	KLEBERG	60	28,510	36,354
201	TIERRA MINERAL DEVELOPMENT	NUECES	1	28,510	606

TEXAS SMALL-VOLUME FACILITIES - ZERO DISCHARGE

Printed: 27-May-94

Permit No.	Operator	County	Current Volume (BPD)	Cap. Cost ($)	O&M Cost ($/yr
547	WAINOCO OIL & GAS CO	KLEBERG	2	28,510	1,212
170	WESTLAND OIL DEVELOPMENT CORP	JEFFERSON	1	28,510	606
552	WILSON HYDROCARBON, INC	CALHOUN	60	28,510	36,354
			1,033	1,083,380	625,895

LOUISIANA MEDIUM/LARGE-VOLUME FACILITIES - GAS FLOTATION

Printed: 22-Sept-94

Permit-Outfall Number	Operator	Current Avg. Vol (bpd)	Future Avg. Volume (bpd)	O&M Cost ($/yr)	Cap. Cost ($)	Piping Cost ($)	Total Cap. Cost ($)
3040-001	Alliance Operating Corp.	1,678.0	2,517.0	23,756	179,202	0	179,202
3650-001	Alltex Exploration, Inc.	465.0	697.5	23,488	170,705	0	170,705
3408-001	Amerada Hess Corp.	3,662.0	5,493.0	38,192	345,251	0	345,251
2184-001 to 003	Ashlawn Energy, Inc.	9,428.1	14,142.2	41,304	399,984	434,095	834,079
3795-001	Atlas Production Services, Inc.	151.5	227.3	23,563	171,847	0	171,847
3795-002	Atlas Production Services, Inc.	151.5	227.3	23,563	171,847	0	171,847
3686-001	Bois d'Arc Operating Corp.	925.0	1,387.5	23,486	171,511	0	171,511
3870-001	Bois d'Arc Operating Corp.	1,010.0	1,515.0	23,499	171,983	0	171,983
3086-001	Burk Royalty Co.	450	675.0	23,490	170,729	0	170,729
1901-001	Callon Offshore Production, Inc.	30,200.0	45,300.0	52,516	597,157	0	597,157
1901-002	Callon Offshore Production, Inc.	30,200.0	45,300.0	52,516	597,157	0	597,157
1934-001-1	Callon Offshore Production, Inc.	14,443.0	21,664.5	44,011	447,587	0	447,587
2142-001-1	Callon Offshore Production, Inc.	12,076.0	18,114.0	42,733	425,119	0	425,119
2672-001-2	Callon Offshore Production, Inc.	9,175.0	13,762.5	41,167	397,582	0	397,582
2859-001	Callon Offshore Production, Inc.	11,290.0	16,935.0	42,309	417,658	0	417,658
2860-003	Callon Offshore Production, Inc.	7,120.0	10,680.0	40,058	378,075	0	378,075
3074-001	Cashco Oil Co.	72.0	108.0	23,591	172,355	0	172,355
1857-001 to 011	Chevron U.S.A., Inc.	18,659.7	27,989.6	46,287	487,613	1,522,227	2,009,840
1861-001	Chevron U.S.A., Inc.	4,600.0	6,900.0	38,698	354,155	0	354,155
1863	Chevron U.S.A., Inc.	27,856.0	41,784.0	51,251	574,907	0	574,907
1896	Chevron U.S.A., Inc.	35,652.0	53,478.0	55,459	648,908	0	648,908
3853-001	Cliffs Oil & Gas Co.	245.0	367.5	23,534	171,363	0	171,363
3038-001	CXY Energy, Inc.	500.0	750.0	23,484	170,663	0	170,663
3067-000	Denovo Oil and Gas, Inc.	200.0	300.0	23,547	171,581	0	171,581
2185-001	Energy Development Corp.	700.0	1,050.0	23,471	170,748	0	170,748
2785-001	Energy Development Corp.	250.0	375.0	23,533	171,341	0	171,341
2779-001	Graham Royalty, Ltd.	950.0	1,425.0	23,489	171,640	0	171,640
4029-001	Hilcorp Energy Co.	3,522.0	5,283.0	38,116	343,922	0	343,922
4467-001	Houma Production Co.	400.0	600.0	23,499	170,829	0	170,829
2704-001	Hunt Petroleum Co.	75.0	112.5	23,590	172,334	0	172,334
2368-001	Hunt Petroleum Co.	1,125.0	1,687.5	23,524	172,783	0	172,783
2368-002	Hunt Petroleum Co.	1,125.0	1,687.5	23,524	172,783	0	172,783
2368-003	Hunt Petroleum Co.	1,125.0	1,687.5	23,524	172,783	0	172,783
2368-005	Hunt Petroleum Co.	1,125.0	1,687.5	23,524	172,783	0	172,783
2368-006	Hunt Petroleum Co.	1,125.0	1,687.5	23,524	172,783	0	172,783
3008-001	Hunt Petroleum Co.	266.0	399.0	23,529	171,271	0	171,271
3029-001	James A. Whitson, Jr.	300.0	450.0	23,520	171,135	0	171,135
3081-001	Konantz, Inc.	613.0	919.5	23,474	170,642	0	170,642

LOUISIANA MEDIUM/LARGE-VOLUME FACILITIES - GAS FLOTATION

Printed: 22-Sept-94

Permit-Outfall Number	Operator	Current Avg. Vol (bpd)	Future Avg. Volume (bpd)	O&M Cost ($/yr)	Cap. Cost ($)	Piping Cost ($)	Total Cap. Cost ($)
2710-001	Linder Oil Co.	904.0	1,356.0	23,483	171,410	0	171,410
1853-001	LLECO Holdings, Inc.	324.0	486.0	23,514	171,049	0	171,049
3746-001	Marblehead Energy Corp.	1,250.0	1,875.0	23,561	173,860	0	173,860
2164-001-1	Oryx Energy Co.	150.0	225.0	23,563	171,856	0	171,856
3223-001	Pel-Tex Oil Co.	186.0	279.0	23,552	171,654	0	171,654
3407-001	Pennzoil Exploration & Production Co.	6,300.0	9,450.0	39,615	370,292	0	370,292
2838-001	Petro Corp.	1,500.0	2,250.0	23,661	176,670	0	176,670
2227-001	Quintana Petroleum Corp.	600	900.0	23,474	170,636	0	170,636
2626-001	Samedan Oil Corp.	100.0	150.0	23,581	172,166	0	172,166
2071	Shell	144,000.0	216,000.0	113,940	1,677,375	0	1,677,375
2084-001	Texaco, Inc.	1,715.6	2,573.4	23,778	179,793	0	179,793
2084-003-1	Texaco, Inc.	1,715.6	2,573.4	23,778	179,793	0	179,793
2084-005	Texaco, Inc.	1,715.6	2,573.4	23,778	179,793	0	179,793
2084-012	Texaco, Inc.	1,715.6	2,573.4	23,778	179,793	0	179,793
2084-015	Texaco, Inc.	1,715.6	2,573.4	23,778	179,793	0	179,793
2084-016	Texaco, Inc.	1,715.6	2,573.4	23,778	179,793	0	179,793
2816-011	Texaco, Inc.	291.1	436.7	23,522	171,169	0	171,169
2825-001	Texaco, Inc.	666.3	999.5	23,472	170,695	0	170,695
2825-002	Texaco, Inc.	666.3	999.5	23,472	170,695	0	170,695
2825-003	Texaco, Inc.	666.3	999.5	23,472	170,695	0	170,695
2882-001/002	Texaco, Inc.	1,494.0	2,241.0	23,658	176,592	0	176,592
2970-001	Texaco, Inc.	500.0	750.0	23,484	170,663	0	170,663
2971-001	Texaco, Inc.	2,650.0	3,975.0	24,607	200,824	0	200,824
2971-002	Texaco, Inc.	2,650.0	3,975.0	24,607	200,824	0	200,824
3032-001	Texoil Co.	939.0	1,408.5	23,488	171,582	0	171,582
2547-001	Torch Operating Co.	109.0	163.5	23,577	172,108	0	172,108
2708-001	Torch Operating Co.	278.0	417.0	23,526	171,221	0	171,221
1950-001	Warren Petroleum Co.	1,680.0	2,520.0	23,757	179,233	0	179,233
3039-001	Wichita River Oil Corp.	270.0	405.0	23,528	171,254	0	171,254
2909-001	WRT Energy Corp.	3,252.0	4,878.0	25,419	220,825	0	220,825
2118-001 to 003	W.W.F. Oil Corp	1,110.0	1,665.0	23,521	172,668	216,083	388,751
		415,740		2,031,065			19,911,896

LOUISIANA SMALL–VOLUME FACILITIES – GAS FLOTATION Printed: 16–Jun–94

Permit–Outfall Number	Operator	Current Vol (BPD)	Capital Cost ($)	O&M Cost ($/yr)
2858–001	BKE–A, LLC	1	32,010	595
2699–001	Carl Oil & Gas Co.	30	40,607	17,849
2945–001	Claron Corp.	15	32,010	8,924
3459–000	Desco Oil Co.	34	40,607	20,228
3133–001	DKM Resources, Inc.	22	40,607	13,089
2956–000	Japex (U.S.) Corp.	13	32,010	7,734
2408–001	Linder Oil Co	20	32,010	11,899
2299–001	Quintana Petroleum Corp.	2	32,010	1,190
2138–002/001	Whiting Petroleum Co.	42	40,607	24,988
		179	322,478	106,496

TEXAS MEDIUM/LARGE-VOLUME FACILITIES - GAS FLOTATION

Printed: 16-Jun-94

Permit No.	Operator	Current Volume (BPD)	Future Volume (BPD)	O&M Cost ($/yr)	Cap. Cost ($)	Piping Cost ($)	Total Cap. Cost ($)
163	ACE PRODUCTIONS	450	675	23,490	166,453	0	166,453
136	AMERICAN EXPLORATION CO	4,476	6,714	38,631	340,103	0	340,103
666	AMERICAN EXPLORATION CO	335	503	23,512	166,691	0	166,691
19	APACHE CORP	1,685	2,528	23,760	174,773	453,388	628,161
590	BKN OIL & GAS, INC	2,436	3,654	24,371	189,564	300,973	490,537
684	BRANDES PETROLEUM INC	250	375	23,533	166,978	0	166,978
105	BROWN, CLIFFORD L, JR	2,370	3,555	24,304	187,969	632,814	820,784
90,113	BROWN, GEORGE R. PRTNRSHP	6,670	10,005	39,815	359,500	141,054	500,554
693	BRYMER CONTRACTING CO	436	654	23,493	166,472	0	166,472
673	BWS VACUUM SERVICE, INC.	130	195	23,570	167,544	0	167,544
60	CEDAR POINT OIL CO	1,200	1,800	23,545	169,132	0	169,132
675	TABBS BAY/GALVESTON BAY	210	315	23,544	167,146	0	167,146
857	CLARON CORP	175	263	23,555	167,309	0	167,309
904	COASTAL OIL & GAS CORP	4,839	7,259	38,827	343,312	0	343,312
616	CREST RESOURCES & EXPLOR	400	600	23,499	166,535	0	166,535
694	CREST RESOURCES & EXPLOR	180	270	23,553	167,285	0	167,285
710	DAN J HARRISON III&FH BRUCE	150	225	23,563	167,436	0	167,436
637	DENOVO OIL & GAS, INC	652	978	23,472	166,452	0	166,452
241	DEWBRE PETROLEUM CORP	155	233	23,562	167,410	0	167,410
649	DYNAMIC PRODUCTION, INC.	80	120	23,588	167,835	0	167,835
13	ENSENJAY PETROLEUM CORP	1,193	1,790	23,543	169,073	0	169,073
80	EXXON CORP	1,948	2,922	23,936	179,115	0	179,115
81	EXXON CO, USA	888	1,332	23,481	167,126	0	167,126
26	EXXON CORP - HOUSTON	7,495	11,243	40,260	366,794	0	366,794
202	FORT WORTH OIL AND GAS	84	126	23,586	167,810	0	167,810
89	GOODRICH OPERATING CO, INC	137	206	23,568	167,505	0	167,505
739	GRAHAM ROYALTY, LTD	330	495	23,513	166,705	0	166,705
635	GULF VACUUM SERVICE	1,290	1,935	23,574	169,947	0	169,947
627	HAPS OIL & GAS CORP	185	278	23,552	167,261	0	167,261
134	HEADINGTON OIL CO	400	600	23,499	166,535	0	166,535
885	HOUSTON OIL & MINERALS CORP	168	252	23,557	167,344	0	167,344
632	KANSAS OIL & GAS CO	904	1,356	23,483	167,198	0	167,198
152	KEPLINGER OPERATING CO	80	120	23,588	167,835	0	167,835
249	KILLAM OIL CO	3,755	5,633	38,242	333,729	0	333,729
122	KILMARNOCK OIL CO	200	300	23,547	167,191	0	167,191
672	KING OIL	120	180	23,573	167,599	0	167,599
587	LINDA PRODUCTION, INC	80	120	23,588	167,835	0	167,835

TEXAS MEDIUM/LARGE-VOLUME FACILITIES - GAS FLOTATION

Printed: 16-Jun-94

Permit No.	Operator	Current Volume (BPD)	Future Volume (BPD)	O&M Cost ($/yr)	Cap. Cost ($)	Piping Cost ($)	Total Cap. Cost ($)
264	LIVE OAK RESERVES, INC	775	1,163	23,473	166,712	0	166,712
659	LONE OAK DISPOSAL CO	248	372	23,533	166,986	0	166,986
580	LUNDY VACUUM SERVICE, INC	100	150	23,581	167,714	0	167,714
207	MIRESCO, INC	1,033	1,550	23,504	167,900	0	167,900
1	NEUMIN PRODUCTION CO	88	132	23,585	167,786	0	167,786
68	ORANGE PETROLEUM CO	5,759	8,639	39,323	351,446	421,876	773,322
577	PATON OIL CORP	682	1,023	23,471	166,497	0	166,497
789	PAX PETROLEUM CORP	350	525	23,509	166,650	0	166,650
276	PEARL, BILL H. PROD, INC	375	563	23,504	166,588	0	166,588
166	PETRO VEST, INC	100	150	23,581	167,714	0	167,714
167	PETRO VEST, INC	400	600	23,499	166,535	0	166,535
242	PI ENERGY, INC	600	900	23,474	166,401	0	166,401
822	POYNOR CORP	1,000	1,500	23,497	167,700	0	167,700
282	REDFISH BAY OPERATING CORP	110	165	23,577	167,656	0	167,656
613	REDFISH BAY OPERATING CORP	600	900	23,474	166,401	0	166,401
744	SCANA EXPLORATION CO	1,200	1,800	23,545	169,132	0	169,132
127,132	SHELTON, CHARLES, H	574	861	23,476	166,389	270,104	436,493
685	SNR OILFIELD SERVICES, INC	600	900	23,474	166,401	0	166,401
124	S&S ENERGY, INC	783	1,175	23,473	166,736	241,164	407,900
674	TD OPERATING CO	200	300	23,547	167,191	0	167,191
20	TEXACO E & P INC	275	413	23,526	166,884	0	166,884
85	TEXACO E & P INC	112	168	23,576	167,645	0	167,645
155	TEXACO E & P, INC	1,660	2,490	23,745	174,407	0	174,407
156	TEXACO E & P, INC	2,746	4,119	24,722	197,816	0	197,816
157	TEXACO E & P, INC	479	719	23,486	166,420	0	166,420
854	TEXANA OPERATING CO	185	278	23,552	167,261	0	167,261
177	TEXAS PETROLEUM CO	1,500	2,250	23,661	172,259	0	172,259
189	TIERRA MINERAL DEVELOPMENT	2,045	3,068	24,011	180,945	0	180,945
165	UNION OIL CO OF CA	144	216	23,565	167,468	0	167,468
47	UNITED TEXAS CORP (A)	150	225	23,563	167,436	0	167,436
605	WHITTINGTON OPERATING CO	245	368	23,534	166,998	0	166,998
680	ZILKA ENERGY CO	110	165	23,577	167,656	0	167,656
219	ZINN PETROLEUM CO	300	450	23,520	166,798	0	166,798
	TOTAL:	72,064	108,096	1,745,419			15,380,407

TEXAS SMALL-VOLUME FACILITIES - GAS FLOTATION Printed: 16-Jun-94

Permit No.	Operator	Current Volume (BPD)	Cap. Cost ($)	O&M Cost ($/yr
663	AMOCO PRODUCTION CO	15	28,510	9,089
655	BAY OPERATING CO, INC.	15	28,510	9,089
590	BKN OIL & GAS, INC	43	28,510	26,054
590	BKN OIL & GAS, INC	50	28,510	30,295
590	BKN OIL & GAS, INC	40	28,510	24,236
590	BKN OIL & GAS, INC	35	28,510	21,207
590	BKN OIL & GAS, INC	13	28,510	7,877
590	BKN OIL & GAS, INC	32	28,510	19,389
590	BKN OIL & GAS, INC	68	28,510	41,201
195	BRISTOL RESOURCES CORP	16	28,510	9,694
197	BRISTOL RESOURCES CORP	32	28,510	19,389
105	BROWN CLIFFORD L, JR	25	28,510	15,148
214	BROWN, GEORGE R PRTRSHP	22	28,510	13,330
747	CAVALLA ENERGY EXPLORATION CO	43	28,510	26,054
64	COASTAL OIL & GAS CORP	40	28,510	24,236
905	COASTAL OIL & GAS CORP	74	28,510	44,837
628	CONVEST ENERGY CORP	15	28,510	9,089
792	CORPUS CHRISTI LEASEHOLDS, INC	4	28,510	2,424
723	CORPUS CHRISTI OIL & GAS CO	15	28,510	9,089
708	CORPUS CHRISTI OIL & GAS CO	8	28,510	4,847
104	EBB TIDE OIL CO	55	28,510	33,325
71	EBB TIDE OIL CO	4	28,510	2,424
752	HOUSTON OIL PROD ENT, INC	10	28,510	6,059
753	HOUSTON OIL PROD ENT, INC	29	28,510	17,571
102	KARBUHN OIL CO	46	28,510	27,871
184	LA PARRITA OIL & GAS, INC	12	28,510	7,271
582	LAMAR OIL & GAS, INC	70	28,510	42,413
111	MARSHALL PETROLEUM, INC	10	28,510	6,059
238	MERRICO RESOURCES, INC	34	28,510	20,601
206	MIDCON OFFSHORE, INC	10	28,510	6,059
119	M.K. MCDANIEL	44	28,510	26,660
645	OIL LEASE OPERATING CO	10	28,510	6,059
14	PI ENERGY, INC	20	28,510	12,118
4CCC	PI ENERGY, INC	75	28,510	45,443
638	PINELL, H P TRUSTEE	24	28,510	14,542

TEXAS SMALL–VOLUME FACILITIES – GAS FLOTATION Printed: 16–Jun–94

Permit No.	Operator	Current Volume (BPD)	Cap. Cost ($)	O&M Cost ($/yr
595	POYNOR CORP.	72	28,510	43,625
176	S.S.C. GAS PRODUCING CO	60	28,510	36,354
201	TIERRA MINERAL DEVELOPMENT	1	28,510	606
547	WAINOCO OIL & GAS CO	2	28,510	1,212
170	WESTLAND OIL DEVELOPMENT CORP	1	28,510	606
552	WILSON HYDROCARBON, INC	60	28,510	36,354
		1,254	1,168,910	759,799

APPENDIX XI-4

Discharging Facilities in Nueces Bay, Texas

Discharging Facilities in Nueces Bay, Texas

The facilities in the following table are scheduled to stop discharging as of specific dates in 1995, as identified below. These facilities are included in the list of dischargers in Appendix XI-3. These facilities and their cessation dates are identified in a letter from Lori Wrotenbery of the Railroad Commission of Texas to the affected operating companies, dated December 3, 1993. Section XI.3.0 of the Coastal Development Document explains that these facilities were included in the cost anayses for this rulemaking effort.

Permit #	Operator	Flow (bpd)[a]	O&M ($/yr)[b]	Capital (1992$)[b]	Discharge Cessation Date
177	Texas Petroleum Co.	1,500	57,984	199,318	12-3-95
189	Tierra Mineral Devel.	2,045	71,453	217,444	12-3-95
201	Tierra Mineral Devel.	1	606	28,510	12-3-95
249	Killam Oil Co.	3,755	111,140	293,121	12-3-95
577	Paton Oil Corp.	682	37,769	172,112	12-3-95
655	Bay Operating Co.	15	9,089	28,510	12-3-95
685	SNR Oilfield Services, Inc.	600	35,743	169,384	6-3-95
TOTAL	--	8,598	323,784	1,108,399	--

[a]These flow rates are the same as are listed in Appendix XI-3, which are as of January 1994.
[b]These costs are for the zero-discharge option (see Appendix XI-3).

APPENDIX XI-5

Facilty-Specific Capital and O&M Costs

For Two Treatment Options in Cook Inlet

Zero Discharge
Trading Bay Modification Costs

Category	Itemized Cost (92$)	Total Cost (92$)
Materials & Equipment[1]		
(4) Shipping Pumps	574,088	
(3) Pig Launchers	30,426	
(2) 15,000 Barrel Storage Tanks	1,148,177	
(3) Booster Pumps	200,931	
Piping and Instrumentation @ 15%	293,043	
Total Capital Cost with Area Multiplier		4,493,330
Installation Costs		
Installation equal to Capital Cost	4,493,330	4,493,330
Main Equipment Building		
Fully Erected Building	296,612	296,612
Engineering		
Engineering @ 10%	928,327	928,327
Contingency		
Contingency @ 15%	1,392,491	1,392,491
Insurance & Bonding		
Insurance & Bonding @ 4%	371,331	371,331
Total Trading Bay Facility Cost		**11,975,421**
Total Pipeline Costs[2]		**30,199,454**
Grand Total[3]		**42,174,875**

Notes:

1. Trading Bay Production facility currently has gas flotation units for treatment of oil and grease in produced water. Produced water will be filtered using the existing filtration equipment at the platforms. Only add-on equipment is shipping pumps, booster pump, storage tank, and pig launcher for pipe cleaning operations.

2. Pipeline costs consist of costs for installing a separate pipeline to the King Salmon, Grayling, and Dolly Varden platforms. Each pipeline is 6.5 miles.

3. Grand Total is the sum of the trading bay modification costs and the pipeline costs.

Zero Discharge
Platform Modification Costs for King Salmon, Grayling and Dolly Varden Platforms

Category	Itemized Cost (92$)	Total Cost (92$)
Company Labor & Expense		
Project Engineer	40,000	
Hazard Analysis	17,000	
Expense	6,000	
Total		63,000
Contract Engineering		
Design Contract	66,000	66,000
Contract Labor		
Offshore Piping & Structural	310,000	
Electrical & Instrumentation	40,000	
Total		350,000
Contract Services		
Piping/Supports Prefabrication	35,000	
Foam Penetrations	7,500	
Painting	10,000	
PSM Document Revisions	10,000	
Total		62,500
Materials[3]		
Pig Receiver	10,142	
Pipeline, Valves and Fittings	125,343	
Structural Steel	1,914	
Construction Consumables	57,409	
Total		194,808
Construction Supervision/Inspection		
Inspector	54,000	54,000
X-Ray/Non-Destructive Testing		
NDE Contract	12,000	12,000
Logistics		
Boats and Helicopters	30,000	
Offshore Catering	45,000	
Total		75,000
Alaska Region Indirect Expense	10,000	10,000
Contingency		
Contingency @ 10%	90,000	88,737
Per Platform Equipment Cost		**976,045**
Total Cost (3 platforms)		**2,928,135**

Notes:

1. King Salmon, Grayling, and Dolly Varden platforms assumed to each have multi-media filtration equipment for treatment of produced water for TSS. Treatment of produced water for oil and grease will occur at the Trading Bay facility prior to shipment of produced water via pipeline.

2. Each platform has injection equipment and injection wells for waterflooding operations. Produced water will be injected for waterflood purposes utilizing this existing equipment.

3. Platform modifications include connecting the produced water return pipeline to the platform, installing manifolds and platform piping to the existing filtration and injection equipment.

Zero Discharge
Granite Point Modification Costs

Category	Itemized Cost (92$)	Total Cost (92$)
Materials & Equipment[1,2,3]		
5,000 BPD Gas Flotation Unit	134,673	
5,000 BPD Granular Filtration Unit	217,966	
Piping and Installation @ 15%	52,896	
Total Capital Cost with Area Multiplier		811,070
Installation		
Installation equal to Capital Cost	811,070	811,070
Main Equipment Building		
Fully Erected Building	296,612	296,612
Engineering		
Engineering @ 10%	191,875	191,875
Contingency		
Contingency @ 15%	287,813	287,813
Insurance & Bonding		
Insurance & Bonding @ 4%	76,750	76,750
Total Granite Point Cost		**2,475,190**

Notes:

1. Granite Point facility currently has gravity separation treatment for produced water. Add-on equipment includes gas flotation and granular filtration.

2. Pipeline exists from Granite Point to the Spark platform which can be used to pipe the produced water to the platform for injection, thus no pipeline costs are incurred for this facility.

3. Since pipeline exists, it is assumed that storage tanks, booster pumps, pig launcher, and shipping pumps exist at the Granite Point facility.

Zero Discharge
Spark Platform Modification Costs

Category	Itemized Cost (92$)	Total Cost (92$)
Company Labor & Expense		
Project Engineer	40,000	
Hazard Analysis	17,000	
Expense	6,000	
Total		63,000
Contract Engineering		
Design Contract	66,000	66,000
Contract Labor		
Offshore Piping & Structural	310,000	
Electrical & Instrumentation	40,000	
Total		350,000
Contract Services		
Piping/Supports Prefabrication	35,000	
Foam Penetrations	7,500	
Painting	10,000	
PSM Document Revisions	10,000	
Total		62,500
Materials[1,2,4]		
Pipeline, Valves and Fittings	125,343	
Structural Steel	1,914	
Construction Consumables	57,409	
(2) Injection Pumps	58,356	
Total		243,022
Construction Supervision/Inspection		
Inspector	54,000	54,000
X-Ray/Non-Destructive Testing		
NDE Contract	12,000	12,000
Logistics		
Boats and Helicopters	30,000	
Offshore Catering	45,000	
Total		75,000
Alaska Region Indirect Expense	10,000	10,000
Contingency		
Contingency at 10%	93,552	93,552
Subtotal - Capital Costs	1,029,074	1,029,074
Injection Well Costs[3]		
(2) Well Recompletions	1,350,000	1,350,000
Total Platform Spark Cost		**2,379,074**

Notes:

1. Because of the existing pipeline, no are costs incurred for a pig receiver.

2. Since there are no current waterflood operations at the Spark platform, injection pumps are required. A multi-media filtration system exists on the platform from previous waterflooding operations and can be utilized for treatment of TSS. The produced water is treated for oil and grease and TSS at the Granite Point facility prior to pipeline.

3. It was assumed that existing service wells, former waterflood injection wells, can be recompleted for injection of produced water. ("Oil and Gas Exploration and Production Wastes Handling Methods in Coastal Alaska," Prepared for the U.S. EPA by SAIC, January 6, 1995.)

4. Platform modifications include connecting the produced water return pipeline to the platform, installing manifolds and platform piping to the existing filtration and injection equipment.

Zero Discharge
East Foreland Modification Costs

Category	Itemized Cost (92$)	Total Cost (92$)
Materials & Equipment[1]		
10,000 BPD Gas Flotation Unit	148,141	
(1) 15,000 BPD Storage Tank	574,088	
(1) Booster Pump	66,977	
(2) Shipping Pumps	287,044	
(1) Pig Launcher	10,142	
Piping and Instrumentation @ 15%	162,959	
Total Capitol Costs with Area Multiplier		2,498,702
Installation		
Installation equal to Capital Cost	2,498,702	2,498,702
Main Equipment Building		
Fully Erected Building	296,612	296,612
Engineering		
Engineering @ 10%	529,402	529,402
Contingency		
Contingency @ 15%	794,102	794,102
Insurance & Bonding		
Insurance & Bonding @ 4%	211,761	211,761
Total East Foreland Cost		**6,829,280**
Total Pipeline Costs[2]		13,938,091
Total Costs for one pipeline assumed to be 9 miles		
Grand Total		**20,767,371**

Notes:

1. A gas flotation unit is required for treatment of oil and grease. Produced water will be treated for TSS at platform "C" were multi-media filtration equipment exists.

2. Pipeline is assumed to go to "C" platform for a distance of 9 miles (1992 Coastal Oil and Gas Survey).

Zero Discharge
Platform "C" Modification Costs

Category	Itemized Cost (92$)	Total Cost (92$)
Company Labor & Expense		
Project Engineer	40,000	
Hazard Analysis	17,000	
Expense	6,000	
Total		63,000
Contract Engineering		
Design Contract	66,000	66,000
Contract Labor		
Offshore Piping & Structural	310,000	
Electrical & Instrumentation	40,000	
Total		350,000
Contract Services		
Piping/Supports Prefabrication	35,000	
Foam Penetrations	7,500	
Painting	10,000	
PSM Document Revisions	10,000	
Total		62,500
Materials[3]		
Pig Receiver	10,142	
Pipeline, Valves and Fittings	125,343	
Structural Steel	1,914	
Construction Consumables	57,409	
Total		194,808
Construction Supervision/Inspection		
Inspector	54,000	54,000
X-Ray/Non-Destructive Testing		
NDE Contract	12,000	12,000
Logistics		
Boats and Helicopters	30,000	
Offshore Catering	45,000	
Total		75,000
Alaska Region Indirect Expense	10,000	10,000
Contingency		
Contingency at 10%	88,737	88,737
Total Platform Cost		**976,045**

Notes:

1. Platform "C" has existing filtration and injection equipment and disposal wells, thus equipment costs are not incurred for this platform.

2. It was assumed that existing service wells can be used for injection of produced water. ("Oil and Gas Exploration and Production Wastes Handling Methods in Coastal Alaska," (Draft) prepared for the U.S. Environmental Protection Agency by SAIC, January 6, 1995.

3. Platform modifications include connecting the produced water return pipeline to the platform, installing manifolds and platform piping to the existing filtration and injection equipment.

Zero Discharge
Onshore Facility Chemical Treatment Costs

Facility	Chemical Cost[1] (1992$)
TRADING BAY	
Scale Inhibitor	713,941
Biocide	908,895
GRANITE POINT	
Scale Inhibitor	5,319
Biocide	6,772
EAST FORELAND	
Scale Inhibitor	34,125
Biocide	43,568

Notes:

1. Chemical costs estimated based on confidential business information submitted as part of the 1992 Coastal Oil and Gas Survey.

Zero Discharge
Onshore Facility/Platform Workover Costs

Facility/Platform	Cost (1992$)[1]
TRADING BAY	
King Salmon	31,164
Grayling	35,616
Dolly Varden	31,164
Total	97,944
GRANITE POINT	
Spark	4,452
EAST FORELAND	
Platform "C"	4,452

Notes:

1. Workover costs estimated based on confidential business information submitted as part of the 1992 Coastal Oil and Gas Survey.

Zero Discharge
Dillon Platform Modification Costs[1]

Category	Itemized Cost (92$)	Total Cost (92$)
Materials & Equipment[2]		
10,000 BPD Gas Flotation System	148,141	
Piping and Instrumentation @ 15%	22,221	
Total Capital Cost with Area Multiplier		340,724
Installation		
Gas Flotation Installation	851,811	851,811
Platform Modifications		
Cantilever Deck 266 SF @ $600/SF	159,600	159,600
Engineering		
Engineering @ 10%	135,213	135,213
Contingency		
Contingency @ 15%	202,820	202,820
Insurance & Bonding		
Insurance & Bonding @ 4%	54,085	54,085
Total Dillon Modification Costs		**1,744,253**

Notes:

1. The average produced water flow at the Dillon platform is 5,000 BPD.

2. Dillon platform has existing filtration and injection equipment and injection wells.

Zero Discharge
Bruce Platform Modification Costs[1]

Category	Itemized Cost (92$)	Total Cost (92$)
Materials & Equipment[2]		
1000 BPD Gas Flotation System	105,509	
(2) Injection Pumps	26,606	
Piping and Instrumentation @ 15%	19,817	
Total Capital Cost with Area Multiplier		303,865
Installation		
Gas Flotation and Injection Pump Installation	759,661	759,661
Platform Modifications		
Cantilever Deck 112 SF @ $600/SF	67,200	67,200
Engineering		
Engineering @ 10%	113,073	113,073
Contingency		
Contingency @ 15%	169,609	169,609
Insurance & Bonding		
Insurance & Bonding @ 4%	45,229	45,229
Subtotal - Capital Costs	1,458,637	1,458,637
Injection Well Costs[3] (2) Injection Wells	2,394,346	2,394,346
Total Bruce Modification Costs		**3,852,983**

Notes:

1. Bruce platform has an average produced water flow rate of 170 BPD, the peak flow is 700 BPD.

2. Bruce platform has filtration equipment from former waterflood operations.

3. Bruce requires new injection wells because waterflood injection wells were overflooded.

Zero Discharge
Anna Platform Modification Costs[1]

Category	Itemized Cost (92$)	Total Cost (92$)
Materials & Equipment[2]		
5,000 BPD Gas Flotation System	134,673	
Piping and Instrumentation @ 15%	20,201	
Total Capital Cost with Area Multiplier		309,748
Installation		
Gas Flotation Installation	774,370	774,370
Platform Modifications		
Cantilever Deck 210 SF @ $600/SF	126,000	126,000
Engineering		
Engineering @ 10%	121,012	121,012
Contingency		
Contingency @ 15%	181,518	181,518
Insurance & Bonding		
Insurance & Bonding @ 4%	48,405	48,405
Total Anna Modification Costs		**1,561,052**

Notes:

1. Anna has an average produced water flow rate of 1,500 BPD, the peak flow is 2,000 BPD.

2. Anna platform has existing filtration and injection equipment and injection wells.

Zero Discharge
Baker Platform Modification Costs[1]

Category	Itemized Cost (92$)	Total Cost (92$)
Materials & Equipment[2]		
1000 BPD Gas Flotation System	105,509	
Piping and Instrumentation @ 15%	15,826	
Total Capital Cost with Area Multiplier		242,671
Installation		
Gas Flotation Installation	606,677	606,677
Platform Modifications		
Cantilever Deck 112 SF @ $600/SF	67,200	67,200
Engineering		
Engineering @ 10%	91,655	91,655
Contingency		
Contingency @ 15%	137,482	137,482
Insurance & Bonding		
Insurance & Bonding @ 4%	36,662	36,662
Total Baker Modification Costs		**1,182,347**

Notes:

1. Baker has an average produced water flow of 30 BPD, the peak flow is 55 BPD.

2. Baker platform has existing filtration and injection equipment and injection wells.

Zero Discharge
Tyonek Platform Modification Costs[1]

Category	Itemized Cost (92$)	Total Cost (92$)
Materials & Equipment (including installation)[2,3]		
1000 BPD Multi-Media Filtration System	365,605	
Centrifuge Package	148,563	
(2) Injection Pumps	26,606	
Miscellaneous Equipment @ 15%	81,116	
Total Capital Cost with Area Multiplier		1,243,780
Platform Modifications		
Cantilever Deck 400 SF @ $600/SF	240,000	240,000
Engineering		
Engineering (10%)	148,378	148,378
Contingency		
Contingency @ 15%	222,567	222,567
Insurance & Bonding		
Insurance & Bonding @ 4%	59,351	59,351
Subtotal - Capital Costs	1,914,076	1,914,076
Injection Well Costs[3]		
(2) Injection wells	2,394,346	2,394,346
Total Tyonek Modification Costs		**4,308,422**

Notes:

1. Tyonek has an average produced water flow of 170 BPD, the peak flow is 478 BPD.

2. Tyonek platform has existing gravity separation and gas flotation treatment for produced water, no add-on flotation system required.

3. Tyonek platform does not waterflood and requires the addition of filtration and injection equipment and injection wells.

Platform Chemical Treatment Costs

Platform	Chemical Cost[1] (1992$)
DILLON	
Scale Inhibitor	29,551
Biocide	37,620
BRUCE	
Scale Inhibitor	1,005
Biocide	1,279
ANNA	
Scale Inhibitor	8,865
Biocide	11,286
BAKER	
Scale Inhibitor	177
Biocide	226
TYONEK	
Scale Inhibitor	1,005
Biocide	1,279

Notes:

1. Chemical costs estimated based on confidential business information submitted as part of the 1992 Coastal Oil and Gas Survey.

Platform Workover Costs

Platform	Cost[1] (1992$/year)
Dillon	4,452
Bruce	4,452
Anna	4,452
Baker	4,452
Tyonek	4,452

Notes:

1. Workover costs estimated based on confidential business information submitted as part of the 1992 Coastal Oil and Gas Survey.

Gas Flotation
Trading Bay Facility[1,2]

Category	Itemized Cost (92$)	Total Cost (92$)
Materials & Equipment		
(4) 40,000 BPD Gas Flotation Units	754,168	
Piping and Instrumentation @ 15%	113,125	
Total Capital Cost with Area Multiplier		867,294
Installation		
Installation equal to capital cost	867,294	867,294
Engineering		
Engineering @ 10%	173,459	173,459
Contingency		
Contingency @ 15%	260,188	260,188
Insurance & Bonding		
Insurance & Bonding @ 4%	69,383	69,383
Total Trading Bay Cost		**2,237,618**

Notes:

1. These capital costs were developed to estimate operation and maintenance costs for the Trading Bay facility. Trading Bay facility does not incur any capital costs for installation of gas flotation.

2. Trading Bay facility has an average produced water flow of 126,000 BPD, the peak flow is 151,425 BPD.

Gas Flotation
Granite Point Facility[1]

Category	Itemized Cost (92$)	Total Cost (92$)
Materials & Equipment 5,000 BPD Gas Flotation Unit Piping and Instrumentation @ 15% Total Capital Cost with Area Multiplier	134,673 20,201	309,748
Installation Installation equal to capital cost	309,748	309,748
Main Equipment Building Fully Erected Building	296,612	296,612
Engineering Engineering @ 10%	91,611	91,611
Contingency Contingency @ 15%	137,416	137,416
Insurance & Bonding Insurance & Bonding @ 4%	36,644	36,644
Total Granite Point Cost		**1,181,779**

Notes:

1. Granite Point facility has an average produced water flow rate of 300 BPD and a peak flow rate of 1,000 BPD.

Gas Flotation
East Foreland Facility[1]

Category	Itemized Cost (92$)	Total Cost (92$)
Materials & Equipment		
10,000 BPD Gas Flotation Unit	148,141	
Piping and Instrumentation @ 15%	22,221	
Total Capital Costs with Area Multiplier		340,724
Installation		
Installation equal to capital cost	340,724	340,724
Main Equipment Building		
Fully Erected Building	296,612	296,612
Engineering		
Engineering @ 10%	97,806	97,806
Contingency		
Contingency @ 15%	146,709	146,709
Insurance & Bonding		
Insurance & Bonding @ 4%	39,122	39,122
Total East Foreland Cost		**1,261,697**

Notes:

1. East Foreland facility has an average produced water flow rate of 3,300 BPD and a peak flow of 6,240 BPD.

Gas Flotation
Bruce Platform Modification Costs[1]

Category	Itemized Cost	Total Cost
Materials & Equipment		
1000 BPD Gas Flotation System	105,509	
Piping and Instrumentation @ 15%	15,826	
Total Capital Cost with Area Multiplier		242,671
Installation		
Gas Flotation Installation	606,677	606,677
Platform Modifications		
Cantilever Deck 112 SF @ $600/SF	67,200	67,200
Engineering		
Engineering @ 10%	91,655	91,655
Contingency		
Contingency @ 15%	137,482	137,482
Insurance & Bonding		
Insurance & Bonding @ 4%	36,662	36,662
Total Bruce Modification Costs		**1,182,347**

Notes:

1. Bruce platform has an average produced water flow of 170 BPD.

APPENDIX XII-1

TWC Compliance Cost Calculations

EXISTING SOURCES: COMPLIANCE COST ESTIMATE FOR COMPLETION FLUIDS
ZERO DISCHARGE OPTION VIA COMMINGLING AND INJECTION
GULF OF MEXICO COASTAL REGION

Date: 10-24-94

Input Data	
Total 1992 number of wells discharging completion fluids (Sect. XII.3.1.1):	334
Average 1992 volume of completion fluid discharged per well/yr (bbl/yr) (SAIC, Sept. 30, 1994):	209
Percentage of Water-Access Facilities (Sect. XII.3.1.1):	0.656
Percentage of Land-Access Facilities (Sect. XII.3.1.1):	0.344
Percentage of facilities that commingle completion fluids with produced water and inject (i.e., % medium/large facilities) (Sect. XII.3.1.2):	0.77
Percentage of facilities that dispose of completion fluids commercially (Sect. XII.3.1.2):	0.23
Cost to inject completion fluids with produced water at water-access sites ($/bbl) (Sect. XII.3.1.2):	0.08
Cost to inject completion fluids with produced water at land-access sites ($/bbl) (Sect. XII.3.1.2):	0.15
Capacity of small-volume barge (bbls) (Sect. XII.3.1.3):	1500
Assumed portion of barge used per job (i.e., 209 bbls per job require 1/4 of one barge):	0.25
Cost of Barge + Tug Transportation ($/round trip) (Sect. XII.3.1.3):	1000
Cost of 25% of barge transportation ($/job) (Sect. XII.3.1.3):	250
Cost of vacuum truck transportation ($/bbl) (Sect. XII.3.1.3):	1.75
Commercial disposal cost for TWC fluids ($/bbl) (Sect. XII.3.1.3):	8

Injection Costs at Medium/Large-Volume Facilities

Facility Location	# Comp. Jobs/yr	No. Jobs Injected	Vol. Injected/yr (bbl)	Injection Cost ($/yr)
Water-Access	219	169	35,260	2,821
Land-Access	115	88	18,490	2,774
Total	334	257	53,751	5,594

Disposal Costs at Small-Volume Facilities

Facility Location	No. Comp. Jobs per yr	No. Jobs Disp.d Commercially/yr	Volume Disp'd Comm'ly /yr (bbl)	Transport'n Cost ($/yr)	Disposal Cost ($/yr)	Total Transp. + Disp. Cost
Water-Access	219	50	10,532	12,598	84,259	96,857
Land-Access	115	26	5,523	9,665	44,184	53,850
Total	334	77	16,055	22,264	128,443	150,707

TOTAL TRANSPORTATION AND DISPOSAL COST FOR COMPLETION FLUIDS ($/YR): **156,301**

NEW SOURCES: COMPLIANCE COST ESTIMATE FOR WORKOVER/TREATMENT FLUIDS
ZERO DISCHARGE OPTION VIA COMMINGLING AND INJECTION
GULF OF MEXICO COASTAL REGION

Date: 11-10-94

Input Data	
Total number of new sources (wells) generating workover/treatment fluids (SAIC, Sect. XII.3.1.1):	45
Average 1992 volume of workover/treatment fluid discharged per well/yr (bbl/yr) (SAIC, Sept. 30, 19	587
Percentage of Water-Access Facilities (Sect. XII.3.1.1):	0.656
Percentage of Land-Access Facilities (Sect. XII.3.1.1):	0.344
Percentage of facilities that commingle W/T fluids with produced water and inject (i.e., % medium/large facilities) (Sect. XII.3.1.2):	0.77
Percentage of facilities that dispose of W/T fluids commercially (Sect. XII.3.1.2):	0.23
Cost to inject W/T fluids with produced water at water-access sites ($/bbl) (Sect. XII.3.1.2):	0.08
Cost to inject W/T fluids with produced water at land-access sites ($/bbl) (Sect. XII.3.1.2):	0.15
Capacity of small-volume barge (bbls) (Sect. XII.3.1.3):	1500
Assumed portion of barge used per job (i.e., 587 bbls per job require 1/2 of barge):	0.5
Cost of Barge + Tug Transportation ($/round trip) (Sect. XII.3.1.3):	1000
Cost of 50% of barge transportation ($/job) (Sect. XII.3.1.3):	500
Cost of vacuum truck transportation ($/bbl) (Sect. XII.3.1.3):	1.75
Commercial disposal cost for TWC fluids ($/bbl) (Sect. XII.3.1.3):	8

Injection Costs at Medium/Large-Volume Facilities

Facility Location	No. W/T Jobs/yr	No. Jobs Injected	Vol. Injected/yr (bbl)	Injection Cost ($/yr)
Water-Access	30	23	13,343	1,067
Land-Access	15	12	6,997	1,050
Total	45	35	20,340	2,117

Disposal Costs at Small-Volume Facilities

Facility Location	No. W/T Jobs/yr	No. Jobs Disp.d Commercially/yr	Volume Disp'd Comm'ly /yr (bbl)	Transport'n Cost ($/yr)	Disposal Cost ($/yr)	Total Transp. + Disp. Cost
Water-Access	30	7	3,985	3,395	31,884	35,279
Land-Access	15	4	2,090	3,657	16,720	20,377
Total	45	10	6,075	7,052	48,604	55,656

TOTAL TRANSPORTATION AND DISPOSAL COST FOR WORKOVER/TREATMENT FLUIDS ($/YR): 57,773

NEW SOURCES: COMPLIANCE COST ESTIMATE FOR COMPLETION FLUIDS
ZERO DISCHARGE OPTION VIA COMMINGLING AND INJECTION
GULF OF MEXICO COASTAL REGION

Date: 11-10-94

Input Data	
Total number of new sources (wells) generating completion fluids (Sect. XII.3.1.1):	45
Average 1992 volume of completion fluid discharged per well/yr (bbl/yr) (SAIC, Sept. 30, 1994):	209
Percentage of Water-Access Facilities (Sect. XII.3.1.1):	0.656
Percentage of Land-Access Facilities (Sect. XII.3.1.1):	0.344
Percentage of facilities that commingle completion fluids with produced water and inject (i.e., % medium/large facilities) (Sect. XII.3.1.2):	0.77
Percentage of facilities that dispose of completion fluids commercially (Sect. XII.3.1.2):	0.23
Cost to inject completion fluids with produced water at water-access sites ($/bbl) (Sect. XII.3.1.2):	0.08
Cost to inject completion fluids with produced water at land-access sites ($/bbl) (Sect. XII.3.1.2):	0.15
Capacity of small-volume barge (bbls) (Sect. XII.3.1.3):	1500
Assumed portion of barge used per job (i.e., 209 bbls per job require 1/4 of one barge):	0.25
Cost of Barge + Tug Transportation ($/round trip) (Sect. XII.3.1.3):	1000
Cost of 25% of barge transportation ($/job) (Sect. XII.3.1.3):	250
Cost of vacuum truck transportation ($/bbl) (Sect. XII.3.1.3):	1.75
Commercial disposal cost for TWC fluids ($/bbl) (Sect. XII.3.1.3):	8

Injection Costs at Medium/Large-Volume Facilities

Facility Location	# Comp. Jobs/yr	No. Jobs Injected	Vol. Injected/yr (bbl)	Injection Cost ($/yr)
Water-Access	30	23	4,751	380
Land-Access	15	12	2,491	374
Total	45	35	7,242	754

Disposal Costs at Small-Volume Facilities

Facility Location	No. Comp. Jobs per yr	No. Jobs Disp.d Commercially/yr	Volume Disp'd Comm'ly /yr (bbl)	Transport'n Cost ($/yr)	Disposal Cost ($/yr)	Total Transp. + Disp. Cost
Water-Access	30	7	1,419	1,697	11,352	13,050
Land-Access	15	4	744	1,302	5,953	7,255
Total	45	10	2,163	3,000	17,305	20,305

TOTAL TRANSPORTATION AND DISPOSAL COST FOR COMPLETION FLUIDS ($/YR): **21,059**

EXISTING SOURCES: COMPLIANCE COST ESTIMATE FOR WORKOVER/TREATMENT FLUIDS
DISCHARGE OPTION: GAS FLOTATION/COMMERCIAL DISPOSAL
GULF OF MEXICO COASTAL REGION

Date: 10-24-94

Input Data	
Total 1992 number of wells discharging workover/treatment fluids (Sect. XII.3.1.1):	350
Average 1992 volume of workover/treatment fluid discharged per well/yr (bbl/yr) (SAIC, Sept. 30, 1994	587
Percentage of Water-Access Facilities (Sect. XII.3.1.1):	0.656
Percentage of Land-Access Facilities (Sect. XII.3.1.1):	0.344
Percentage of facilities that commingle W/T fluids with produced water and treat with gas flotation (i.e., % medium/large facilities) (Sect. XII.3.1.2):	0.77
Percentage of facilities that dispose of W/T fluids commercially (Sect. XII.3.1.2):	0.23
Cost to treat W/T fluids with gas flotation at water-access sites ($/bbl) (Sect. XII.3.1.2):	0.01
Cost to treat W/T fluids with gas flotation at land-access sites ($/bbl) (Sect. XII.3.1.2):	0.09
Capacity of small-volume barge (bbls) (Sect. XII.3.1.3):	1500
Assumed portion of barge used per job (i.e., 587 bbls per job require 1/2 of one barge):	0.5
Cost of Barge + Tug Transportation ($/round trip) (Sect. XII.3.1.3):	1000
Cost of 50% of barge transportation ($/job) (Sect. XII.3.1.3):	500
Cost of vacuum truck transportation ($/bbl) (Sect. XII.3.1.3):	1.75
Commercial disposal cost for TWC fluids ($/bbl) (Sect. XII.3.1.3):	8

Gas Flotation Treatment Costs at Medium/Large-Volume Facilities

Facility Location	No. W/T Jobs/yr	No. Jobs Treated	Vol. Treated/yr (bbl)	GF Treatm't Cost ($/yr)
Water-Access	230	177	103,777	1,038
Land-Access	120	93	54,420	4,898
Total	350	270	158,197	5,936

Disposal Costs at Small-Volume Facilities

Facility Location	No. W/T Jobs/yr	No. Jobs Disp.d Commercially/yr	Volume Disp'd Comm'ly /yr (bbl)	Transport'n Cost ($/yr)	Disposal Cost ($/yr)	Total Transp. + Disp. Cost
Water-Access	230	53	30,998	26,404	247,986	274,390
Land-Access	120	28	16,255	28,447	130,042	158,488
Total	350	81	47,254	54,851	378,028	432,879

TOTAL TRANSPORTATION AND DISPOSAL COST FOR WORKOVER/TREATMENT FLUIDS ($/YR): 438,814

EXISTING SOURCES: COMPLIANCE COST ESTIMATE FOR COMPLETION FLUIDS
DISCHARGE OPTION: GAS FLOTATION/COMMERCIAL DISPOSAL
GULF OF MEXICO COASTAL REGION

Date: 10-24-94

Input Data	
Total 1992 number of wells discharging completion fluids (Sect. XII-3.1.1):	334
Average 1992 volume of completion fluid discharged per well/yr (bbl/yr) (SAIC, Sept. 30, 1994):	209
Percentage of Water-Access Facilities (Sect. XII.3.1.1):	0.656
Percentage of Land-Access Facilities (Sect. XII.3.1.1):	0.344
Percentage of facilities that commingle completion fluids with produced water and treat with gas flotation (i.e., % medium/large facilities) (Sect. XII.3.1.2):	0.77
Percentage of facilities that dispose of completion fluids commercially (Sect. XII.3.1.2):	0.23
Cost to treat completion fluids with gas flotation at water-access sites ($/bbl) (Sect. XII.3.1.2):	0.01
Cost to treat completion fluids with gas flotation at land-access sites ($/bbl) (Sect. XII.3.1.2):	0.09
Capacity of small-volume barge (bbls) (Sect. XII.3.1.3):	1500
Assumed portion of barge used per job (i.e., 209 bbls per job require 1/4 of one barge):	0.25
Cost of Barge + Tug Transportation ($/round trip) (Sect. XII.3.1.3):	1000
Cost of 25% of barge transportation ($/job) (Sect. XII.3.1.3):	250
Cost of vacuum truck transportation ($/bbl) (Sect. XII.3.1.3):	1.75
Commercial disposal cost for TWC fluids ($/bbl) (Sect. XII.3.1.3):	8

Gas Flotation Treatment Costs at Medium/Large-Volume Facilities

Facility Location	# Comp. Jobs/yr	No. Jobs Treated	Vol. Treated/yr (bbl)	GF Treatm't Cost ($/yr)
Water-Access	219	169	35,260	353
Land-Access	115	88	18,490	1,664
Total	334	257	53,751	2,017

Disposal Costs at Small-Volume Facilities

Facility Location	No. Comp. Jobs per yr	No. Jobs Disp.d Commercially/yr	Volume Disp'd Comm'ly /yr (bbl)	Transport'n Cost ($/yr)	Disposal Cost ($/yr)	Total Transp. + Disp. Cost
Water-Access	219	50	10,532	12,598	84,259	96,857
Land-Access	115	26	5,523	9,665	44,184	53,850
Total	334	77	16,055	22,264	128,443	150,707

TOTAL TRANSPORTATION AND DISPOSAL COST FOR COMPLETION FLUIDS ($/YR): 152,724

NEW SOURCES: COMPLIANCE COST ESTIMATE FOR WORKOVER/TREATMENT FLUIDS
DISCHARGE OPTION: GAS FLOTATION/COMMERCIAL DISPOSAL
GULF OF MEXICO COASTAL REGION

Date: 11-10-94

Input Data	
Total 1992 number of wells discharging workover/treatment fluids (Sect. XII.3.1.1):	45
Average 1992 volume of workover/treatment fluid discharged per well/yr (bbl/yr) (SAIC, Sept. 30, 1994	587
Percentage of Water-Access Facilities (Sect. XII.3.1.1):	0.656
Percentage of Land-Access Facilities (Sect. XII.3.1.1):	0.344
Percentage of facilities that commingle W/T fluids with produced water and treat with gas flotation (i.e., % medium/large facilities) (Sect. XII.?):	0.77
Percentage of facilities that dispose of W/T fluids commercially (Sect. XII.3.1.2):	0.23
Cost to treat W/T fluids with gas flotation at water-access sites ($/bbl) (Sect. XII.3.1.2):	0.01
Cost to treat W/T fluids with gas flotation at land-access sites ($/bbl) (Sect. XII.3.1.2):	0.09
Capacity of small-volume barge (bbls) (Sect. XII.3.1.3):	1500
Assumed portion of barge used per job (i.e., 587 bbls per job require 1/2 of one barge):	0.5
Cost of Barge + Tug Transportation ($/round trip) (Sect. XII.3.1.3):	1000
Cost of 50% of barge transportation ($/job) (Sect. XII.3.1.3):	500
Cost of vacuum truck transportation ($/bbl) (Sect. XII.3.1.3):	1.75
Commercial disposal cost for TWC fluids ($/bbl) (Sect. XII.3.1.3):	8

Gas Flotation Treatment Costs at Medium/Large-Volume Facilities

Facility Location	No. W/T Jobs/yr	No. Jobs Treated	Vol. Treated/yr (bbl)	GF Treatm't Cost ($/yr)
Water-Access	30	23	13,343	133
Land-Access	15	12	6,997	630
Total	45	35	20,340	763

Disposal Costs at Small-Volume Facilities

Facility Location	No. W/T Jobs/yr	No. Jobs Disp.d Commercially/yr	Volume Disp'd Comm'ly /yr (bbl)	Transport'n Cost ($/yr)	Disposal Cost ($/yr)	Total Transp. + Disp. Cost
Water-Access	30	7	3,985	3,395	31,884	35,279
Land-Access	15	4	2,090	3,657	16,720	20,377
Total	45	10	6,075	7,052	48,604	55,656

TOTAL TRANSPORTATION AND DISPOSAL COST FOR WORKOVER/TREATMENT FLUIDS ($/YR): 56,419

NEW SOURCES: COMPLIANCE COST ESTIMATE FOR COMPLETION FLUIDS
DISCHARGE OPTION: GAS FLOTATION/COMMERCIAL DISPOSAL
GULF OF MEXICO COASTAL REGION

Date: 11-10-94

Input Data	
Total 1992 number of wells discharging completion fluids (Sect. XII-3.1.1):	45
Average 1992 volume of completion fluid discharged per well/yr (bbl/yr) (SAIC, Sept. 30, 1994):	209
Percentage of Water-Access Facilities (Sect. XII.3.1.1):	0.656
Percentage of Land-Access Facilities (Sect. XII.3.1.1):	0.344
Percentage of facilities that commingle completion fluids with produced water and treat with gas flotation (i.e., % medium/large facilities) (Sect. XII.3.1.2):	0.77
Percentage of facilities that dispose of completion fluids commercially (Sect. XII.3.1.2):	0.23
Cost to treat completion fluids with gas flotation at water-access sites ($/bbl) (Sect. XII.3.1.2):	0.01
Cost to treat completion fluids with gas flotation at land-access sites ($/bbl) (Sect. XII.3.1.2):	0.09
Capacity of small-volume barge (bbls) (Sect. XII.3.1.3):	1500
Assumed portion of barge used per job (i.e., 209 bbls per job require 1/4 of one barge):	0.25
Cost of Barge + Tug Transportation ($/round trip) (Sect. XII.3.1.3):	1000
Cost of 25% of barge transportation ($/job) (Sect. XII.3.1.3):	250
Cost of vacuum truck transportation ($/bbl) (Sect. XII.3.1.3):	1.75
Commercial disposal cost for TWC fluids ($/bbl) (Sect. XII.3.1.3):	8

Gas Flotation Treatment Costs at Medium/Large-Volume Facilities

Facility Location	# Comp. Jobs/yr	No. Jobs Treated	Vol. Treated/yr (bbl)	GF Treatm't Cost ($/yr)
Water-Access	30	23	4,751	48
Land-Access	15	12	2,491	224
Total	45	35	7,242	272

Disposal Costs at Small-Volume Facilities

Facility Location	No. Comp. Jobs per yr	No. Jobs Disp.d Commercially/yr	Volume Disp'd Comm'ly /yr (bbl)	Transport'n Cost ($/yr)	Disposal Cost ($/yr)	Total Transp. + Disp. Cost
Water-Access	30	7	1,419	1,697	11,352	13,050
Land-Access	15	4	744	1,302	5,953	7,255
Total	45	10	2,163	3,000	17,305	20,305

TOTAL TRANSPORTATION AND DISPOSAL COST FOR COMPLETION FLUIDS ($/YR): 20,577

APPENDIX XII-2

TWC Polluntant Reduction Calculations

Existing Sources
Annual Workover/Treatment Fluids Pollutant Removals
Zero Discharge Option

Pollutant Parameter	Concentration (ug/l) Current-Level Effluent	Concentration (ug/l) Treatment-Level Effluent	Volume Currently Discharged (bbls)	Loadings (lbs) Current-Level Effluent	Loadings (lbs) Treat.-Level Effluent	Removals (lbs) Incremental
Conventionals						
Oil & Grease	231,688.00	0.00	205,450	16,647	0	16,647
Solids, Total Suspended	520,375.00	0.00	205,450	37,390	0	37,390
Total Conventionals				**54,038**	**0**	**54,038**
Priority Pollutant Organics						
Benzene	1,341.00	0.00	205,450	96	0	96
Ethylbenzene	1,149.00	0.00	205,450	83	0	83
Methyl Chloride (Chloromethane)	29.00	0.00	205,450	2	0	2
Toluene	891.00	0.00	205,450	64	0	64
Fluorene	62.00	0.00	205,450	4	0	4
Naphthalene	525.00	0.00	205,450	38	0	38
Phenanthrene	64.00	0.00	205,450	5	0	5
Phenol	263.00	0.00	205,450	19	0	19
Total P.P. Organics				**311**	**0**	**311**
Priority Pollutant Metals						
Antimony	29.60	0.00	205,450	2	0	2
Arsenic	166.00	0.00	205,450	12	0	12
Beryllium	8.64	0.00	205,450	1	0	1
Cadmium	26.08	0.00	205,450	2	0	2
Chromium	616.82	0.00	205,450	44	0	44
Copper	277.20	0.00	205,450	20	0	20
Lead	1,376.00	0.00	205,450	99	0	99
Nickel	115.52	0.00	205,450	8	0	8
Selenium	42.94	0.00	205,450	3	0	3
Silver	1.60	0.00	205,450	0	0	0
Thallium	13.46	0.00	205,450	1	0	1
Zinc	362.94	0.00	205,450	26	0	26
Total P.P. Metals				**218**	**0**	**218**
Other Non-Conventionals						
Aluminum	6,468.40	0.00	205,450	465	0	465
Barium	498.10	0.00	205,450	36	0	36
Boron	15,042.00	0.00	205,450	1,081	0	1,081
Calcium	10,284,000.00	0.00	205,450	738,935	0	738,935
Cobalt	8.18	0.00	205,450	1	0	1
Cyanide, Total	52.00	0.00	205,450	4	0	4
Iron	384,412.00	0.00	205,450	27,621	0	27,621
Manganese	5,146.60	0.00	205,450	370	0	370
Magnesium	5,052,280.00	0.00	205,450	363,021	0	363,021
Molybdenum	63.00	0.00	205,450	5	0	5
Sodium	18,886,000.00	0.00	205,450	1,357,013	0	1,357,013
Strontium	142,720.00	0.00	205,450	10,255	0	10,255
Sulfur	245,300.00	0.00	205,450	17,626	0	17,626
Tin	27.00	0.00	205,450	2	0	2
Titanium	74.58	0.00	205,450	5	0	5
Vanadium	1,156.00	0.00	205,450	83	0	83
Yttrium	41.92	0.00	205,450	3	0	3
Acetone	7,205.00	0.00	205,450	518	0	518
Methyl Ethyl Ketone (2-Butanone)	58.00	0.00	205,450	4	0	4
M-Xylene	1,785.00	0.00	205,450	128	0	128
O-+P-Xylene	890.00	0.00	205,450	14,762	0	14,762
4-Methyl-2-Pentanone	3,028.00	0.00	205,450	218	0	218
Dibenzofuran	137.00	0.00	205,450	10	0	10
Dibenzothiophene	111.00	0.00	205,450	8	0	8
N-Decane (N-C10)	275.00	0.00	205,450	20	0	20
N-Docosane (N-C22)	771.00	0.00	205,450	55	0	55
N-Dodecane (N-C12)	576.00	0.00	205,450	41	0	41
N-Eicosane (N-C20)	226.00	0.00	205,450	16	0	16
N-Hexacosane (N-C26)	481.00	0.00	205,450	35	0	35
N-Hexadecane (N-C16)	404.00	0.00	205,450	29	0	29
N-Octacosane (N-C28)	211.00	0.00	205,450	15	0	15
N-Octadecane (N-C18)	1,075.00	0.00	205,450	77	0	77
N-Tetracosane (N-C24)	801.00	0.00	205,450	58	0	58
N-Tetradecane (N-C14)	1,237.00	0.00	205,450	89	0	89
P-Cymene	72.00	0.00	205,450	5	0	5
Pentamethylbenzene	54.00	0.00	205,450	4	0	4
1-Methylfluorene	82.00	0.00	205,450	6	0	6
2-Methylnaphthalene	817.00	0.00	205,450	59	0	59
Total Non-Conventionals				**2,532,680**	**0**	**2,532,680**
Grand Total Pollutant Loadings\Removals				**2,587,247**	**0**	**2,587,247**

Existing Sources
Annual Completion Fluids Pollutant Removals
Zero Discharge Option

Pollutant Parameter	Concentration (ug/l) Current-Level Effluent	Concentration (ug/l) Treatment-Level Effluent	Volume Currently Discharged (bbls)	Loadings (lbs) Current-Level Effluent	Loadings (lbs) Treat.-Level Effluent	Removals (lbs) Incremental
Conventionals						
Oil & Grease	231,688.00	0	69,806	5,656	0	5,656
Solids, Total Suspended	520,375.00	0	69,806	12,704	0	12,704
Total Conventionals				18,361	0	18,361
Priority Pollutant Organics						
Benzene	1,341.00	0	69,806	33	0	33
Ethylbenzene	1,149.00	0	69,806	28	0	28
Methyl Chloride (Chloromethane)	29.00	0	69,806	1	0	1
Toluene	891.00	0	69,806	22	0	22
Fluorene	62.00	0	69,806	2	0	2
Naphthalene	525.00	0	69,806	13	0	13
Phenanthrene	64.00	0	69,806	2	0	2
Phenol	263.00	0	69,806	6	0	6
Total P. P. Organics				106	0	106
Priority Pollutant Metals						
Antimony	29.60	0	69,806	1	0	1
Arsenic	166.00	0	69,806	4	0	4
Beryllium	8.64	0	69,806	0	0	0
Cadmium	26.08	0	69,806	1	0	1
Chromium	616.82	0	69,806	15	0	15
Copper	277.20	0	69,806	7	0	7
Lead	1,376.00	0	69,806	34	0	34
Nickel	115.52	0	69,806	3	0	3
Selenium	42.94	0	69,806	1	0	1
Silver	1.60	0	69,806	0	0	0
Thallium	13.46	0	69,806	0	0	0
Zinc	362.94	0	69,806	9	0	9
Total P.P. Metals				74	0	74
Other Non-Conventionals						
Aluminum	6,468.40	0	69,806	158	0	158
Barium	498.10	0	69,806	12	0	12
Boron	15,042.00	0	69,806	367	0	367
Calcium	10,284,000.00	0	69,806	251,069	0	251,069
Cobalt	8.18	0	69,806	0	0	0
Cyanide, Total	52.00	0	69,806	1	0	1
Iron	384,412.00	0	69,806	9,385	0	9,385
Manganese	5,146.60	0	69,806	126	0	126
Magnesium	5,052,280.00	0	69,806	123,344	0	123,344
Molybdenum	63.00	0	69,806	2	0	2
Sodium	18,886,000.00	0	69,806	461,074	0	461,074
Strontium	142,720.00	0	69,806	3,484	0	3,484
Sulfur	245,300.00	0	69,806	5,989	0	5,989
Tin	27.00	0	69,806	1	0	1
Titanium	74.58	0	69,806	2	0	2
Vanadium	1,156.00	0	69,806	28	0	28
Yttrium	41.92	0	69,806	1	0	1
Acetone	7,205.00	0	69,806	176	0	176
Methyl Ethyl Ketone (2-Butanone)	58.00	0	69,806	1	0	1
M-Xylene	1,785.00	0	69,806	44	0	44
O-+P-Xylene	890.00	0	69,806	1,704	0	1,704
4-Methyl-2-Pentanone	3,028.00	0	69,806	74	0	74
Dibenzofuran	137.00	0	69,806	3	0	3
Dibenzothiophene	111.00	0	69,806	3	0	3
N-Decane (N-C10)	275.00	0	69,806	7	0	7
N-Docosane (N-C22)	771.00	0	69,806	19	0	19
N-Dodecane (N-C12)	576.00	0	69,806	14	0	14
N-Eicosane (N-C20)	226.00	0	69,806	6	0	6
N-Hexacosane (N-C26)	481.00	0	69,806	12	0	12
N-Hexadecane (N-C16)	404.00	0	69,806	10	0	10
N-Octacosane (N-C28)	211.00	0	69,806	5	0	5
N-Octadecane (N-C18)	1,075.00	0	69,806	26	0	26
N-Tetracosane (N-C24)	801.00	0	69,806	20	0	20
N-Tetradecane (N-C14)	1,237.00	0	69,806	30	0	30
P-Cymene	72.00	0	69,806	2	0	2
Pentamethylbenzene	54.00	0	69,806	1	0	1
1-Methylfluorene	82.00	0	69,806	2	0	2
2-Methylnaphthalene	817.00	0	69,806	20	0	20
Total Non-Conventionals				857,220	0	857,220
Grand Total Pollutant Loadings\Removals				**875,760**	**0**	**875,760**

New Sources
Annual Workover/Treatment Fluids Pollutant Removals
Zero Discharge Option

Pollutant Parameter	Concentration (ug/l) Pollutant Averages	Treatment-Level Effluent	Volume Currently Discharged (bbls)	Loadings (lbs) Current-Level Effluent	Treat.-Level Effluent	Removals (lbs) Incremental
Conventionals						
Oil & Grease	231,688.00	0.00	26,415	2,140	0	2,140
Solids, Total Suspended	520,375.00	0.00	26,415	4,807	0	4,807
Total Conventionals				**6,948**	**0**	**6,948**
Priority Pollutant Organics						
Benzene	1,341.00	0.00	26,415	12	0	12
Ethylbenzene	1,149.00	0.00	26,415	11	0	11
Methyl Chloride (Chloromethane)	29.00	0.00	26,415	0	0	0
Toluene	891.00	0.00	26,415	8	0	8
Fluorene	62.00	0.00	26,415	1	0	1
Naphthalene	525.00	0.00	26,415	5	0	5
Phenanthrene	64.00	0.00	26,415	1	0	1
Phenol	263.00	0.00	26,415	2	0	2
Total P.P. Organics				**40**	**0**	**40**
Priority Pollutant Metals						
Antimony	29.60	0.00	26,415	0	0	0
Arsenic	166.00	0.00	26,415	2	0	2
Beryllium	8.64	0.00	26,415	0	0	0
Cadmium	26.08	0.00	26,415	0	0	0
Chromium	616.82	0.00	26,415	6	0	6
Copper	277.20	0.00	26,415	3	0	3
Lead	1,376.00	0.00	26,415	13	0	13
Nickel	115.52	0.00	26,415	1	0	1
Selenium	42.94	0.00	26,415	0	0	0
Silver	1.60	0.00	26,415	0	0	0
Thallium	13.46	0.00	26,415	0	0	0
Zinc	362.94	0.00	26,415	3	0	3
Total P.P. Metals				**28**	**0**	**28**
Other Non-Conventionals						
Alumimum	6,468.40	0.00	26,415	60	0	60
Barium	498.10	0.00	26,415	5	0	5
Boron	15,042.00	0.00	26,415	139	0	139
Calcium	10,284,000.00	0.00	26,415	95,006	0	95,006
Cobalt	8.18	0.00	26,415	0	0	0
Cyanide, Total	52.00	0.00	26,415	0	0	0
Iron	384,412.00	0.00	26,415	3,551	0	3,551
Manganese	5,146.60	0.00	26,415	48	0	48
Magnesium	5,052,280.00	0.00	26,415	46,674	0	46,674
Molybdenum	63.00	0.00	26,415	1	0	1
Sodium	18,886,000.00	0.00	26,415	174,473	0	174,473
Strontium	142,720.00	0.00	26,415	1,318	0	1,318
Sulfur	245,300.00	0.00	26,415	2,266	0	2,266
Tin	27.00	0.00	26,415	0	0	0
Titanium	74.58	0.00	26,415	1	0	1
Vanadium	1,156.00	0.00	26,415	11	0	11
Yttrium	41.92	0.00	26,415	0	0	0
Acetone	7,205.00	0.00	26,415	67	0	67
Methyl Ethyl Ketone (2-Butanone)	58.00	0.00	26,415	1	0	1
M-Xylene	1,785.00	0.00	26,415	16	0	16
O-+P-Xylene	890.00	0.00	26,415	244	0	244
4-Methyl-2-Pentanone	3,028.00	0.00	26,415	28	0	28
Dibenzofuran	137.00	0.00	26,415	1	0	1
Dibenzothiophene	111.00	0.00	26,415	1	0	1
N-Decane (N-C10)	275.00	0.00	26,415	3	0	3
N-Docosane (N-C22)	771.00	0.00	26,415	7	0	7
N-Dodecane (N-C12)	576.00	0.00	26,415	5	0	5
N-Eicosane (N-C20)	226.00	0.00	26,415	2	0	2
N-Hexacosane (N-C26)	481.00	0.00	26,415	4	0	4
N-Hexadecane (N-C16)	404.00	0.00	26,415	4	0	4
N-Octacosane (N-C28)	211.00	0.00	26,415	2	0	2
N-Octadecane (N-C18)	1,075.00	0.00	26,415	10	0	10
N-Tetracosane (N-C24)	801.00	0.00	26,415	7	0	7
N-Tetradecane (N-C14)	1,237.00	0.00	26,415	11	0	11
P-Cymene	72.00	0.00	26,415	1	0	1
Pentamethylbenzene	54.00	0.00	26,415	0	0	0
1-Methylfluorene	82.00	0.00	26,415	1	0	1
2-Methylnaphthalene	817.00	0.00	26,415	8	0	8
Total Non-Conventionals				**323,976**	**0**	**323,976**
Grand Total Pollutant Loadings\Removals				**330,992**		**330,992**

New Sources
Annual Completion Fluids Pollutant Removals
Zero Discharge Option Via Commingling and Injection

Pollutant Parameter	Concentration (mg/l) Pollutant Averages	Treatment-Level Effluent	Volume Currently Discharged (bbls)	Loadings (lbs) Current-Level Effluent	Treat.-Level Effluent	Removals (lbs) Incremental
Conventionals						
Oil & Grease	231,688	0	9,405	762	0	762
Solids, Total Suspended	520,375	0	9,405	1,712	0	1,712
Total Conventionals				**2,474**	**0**	**2,474**
Priority Pollutant Organics						
Benzene	1,341	0	9,405	4	0	4
Ethylbenzene	1,149	0	9,405	4	0	4
Methyl Chloride (Chloromethane)	29	0	9,405	0	0	0
Toluene	891	0	9,405	3	0	3
Fluorene	62	0	9,405	0	0	0
Naphthalene	525	0	9,405	2	0	2
Phenanthrene	64	0	9,405	0	0	0
Phenol	263	0	9,405	1	0	1
Total P.P. Organics				**14**	**0**	**14**
Priority Pollutant Metals						
Antimony	30	0	9,405	0	0	0
Arsenic	166	0	9,405	1	0	1
Beryllium	9	0	9,405	0	0	0
Cadmium	26	0	9,405	0	0	0
Chromium	617	0	9,405	2	0	2
Copper	277	0	9,405	1	0	1
Lead	1,376	0	9,405	5	0	5
Nickel	116	0	9,405	0	0	0
Selenium	43	0	9,405	0	0	0
Silver	2	0	9,405	0	0	0
Thallium	13	0	9,405	0	0	0
Zinc	363	0	9,405	1	0	1
Total P.P. Metals				10	0	10
Other Non-Conventionals						
Aluminum	6,468	0	9,405	21	0	21
Barium	498	0	9,405	2	0	2
Boron	15,042	0	9,405	49	0	49
Calcium	10,284,000	0	9,405	33,827	0	33,827
Cobalt	8	0	9,405	0	0	0
Cyanide, Total	52	0	9,405	0	0	0
Iron	384,412	0	9,405	1,264	0	1,264
Manganese	5,147	0	9,405	17	0	17
Magnesium	5,052,280	0	9,405	16,618	0	16,618
Molybdenum	63	0	9,405	0	0	0
Sodium	18,886,000	0	9,405	62,121	0	62,121
Strontium	142,720	0	9,405	469	0	469
Sulfur	245,300	0	9,405	807	0	807
Tin	27	0	9,405	0	0	0
Titanium	75	0	9,405	0	0	0
Vanadium	1,156	0	9,405	4	0	4
Yttrium	42	0	9,405	0	0	0
Acetone	7,205	0	9,405	24	0	24
Methyl Ethyl Ketone (2-Butanone)	58	0	9,405	0	0	0
M-Xylene	1,785	0	9,405	6	0	6
O-+P-Xylene	890	0	9,405	31	0	31
4-Methyl-2-Pentanone	3,028	0	9,405	10	0	10
Dibenzofuran	137	0	9,405	0	0	0
Dibenzothiophene	111	0	9,405	0	0	0
N-Decane (N-C10)	275	0	9,405	1	0	1
N-Docosane (N-C22)	771	0	9,405	3	0	3
N-Dodecane (N-C12)	576	0	9,405	2	0	2
N-Eicosane (N-C20)	226	0	9,405	1	0	1
N-Hexacosane (N-C26)	481	0	9,405	2	0	2
N-Hexadecane (N-C16)	404	0	9,405	1	0	1
N-Octacosane (N-C28)	211	0	9,405	1	0	1
N-Octadecane (N-C18)	1,075	0	9,405	4	0	4
N-Tetracosane (N-C24)	801	0	9,405	3	0	3
N-Tetradecane (N-C14)	1,237	0	9,405	4	0	4
P-Cymene	72	0	9,405	0	0	0
Pentamethylbenzene	54	0	9,405	0	0	0
1-Methylfluorene	82	0	9,405	0	0	0
2-Methylnaphthalene	817	0	9,405	3	0	3
Total Non-Conventionals				**115,295**	**0**	**115,295**
Grand Total Pollutant Loadings\Removals				**117,793**		**117,793**

Existing Sources
Annual Workover/Treatment Fluids Pollutant Removals
Discharge Option
Medium/Large–Volume Facilities Use Gas Flotation; Small–Volume Facilities Use Commercial Disposal

Pollutant Parameter	Concentration (ug/l)			Vol. Currently Discharged (bbls)	Vol. Using GF (bbls)	Vol. Using Comm. Disp. (bbls)	Loading (lbs)			Removals (lbs)
	Current–Level Effluent	Gas Flotation Effluent	Comm'l Disp'l Effluent				Curr.–Level Effluent	Gas Flot'n Effluent	Comm. Disp Effluent	Incremental
Conventionals										
Oil & Grease	231,688.00	23,500.00	0.00	205,450	158,197	47,254	16,647	1,300	0	15,347
Solids, Total Suspended	520,375.00	30,000.00	0.00	205,450	158,197	47,254	37,390	1,660	0	35,731
Total Conventionals							**54,038**	**2,960**	**0**	**51,078**
Priority Poll. Organics										
Benzene	1,341.00	1,225.91	0.00	205,450	158,197	47,254	96	68	0	29
Ethylbenzene	1,149.00	62.18	0.00	205,450	158,197	47,254	83	3	0	79
Toluene	891.00	827.80	0.00	205,450	158,197	47,254	64	46	0	18
Naphthalene	525.00	92.02	0.00	205,450	158,197	47,254	38	5	0	33
Phenol	263.00	263.00	0.00	205,450	158,197	47,254	19	15	0	4
Total P.P. Organics							**300**	**137**	**0**	**163**
Priority Poll. Metals										
Arsenic	166.00	73.08	0.00	205,450	158,197	47,254	12	4	0	8
Cadmium	26.08	14.47	0.00	205,450	158,197	47,254	2	1	0	1
Copper	277.20	277.20	0.00	205,450	158,197	47,254	20	15	0	5
Lead	1,376.00	124.86	0.00	205,450	158,197	47,254	99	7	0	92
Nickel	115.52	115.52	0.00	205,450	158,197	47,254	8	6	0	2
Zinc	362.94	133.85	0.00	205,450	158,197	47,254	26	7	0	19
Total P.P. Metals							**167**	**41**	**0**	**126**
Non–Conventionals										
Alumimum	6,468.40	49.93	0.00	205,450	158,197	47,254	465	3	0	462
Barium	498.10	498.10	0.00	205,450	158,197	47,254	36	28	0	8
Boron	15,042.00	15,042.00	0.00	205,450	158,197	47,254	1,081	832	0	249
Iron	384,412.00	3,146.15	0.00	205,450	158,197	47,254	27,621	174	0	27,447
Manganese	5,146.60	74.16	0.00	205,450	158,197	47,254	370	4	0	366
Titanium	74.58	4.48	0.00	205,450	158,197	47,254	5	0	0	5
Total Xylenes	2,675.00	378.01	0.00	205,450	158,197	47,254	192	21	0	171
Tot. Non–Conventionals							**29,770**	**1,062**	**0**	**28,708**
Grand Total Pollutant Loadings/Removals							**84,274**	**4,199**	**0**	**80,075**

Existing Sources
Annual Completion Fluids Pollutant Removals
Discharge Option
Medium/Large-Volume Facilities Use Gas Flotation; Small-Volume Facilities Use Commercial Disposal

Pollutant Parameter	Concentration (ug/l)			Vol. Currently Discharged (bbls)	Vol. Using GF (bbls)	Vol. Using Comm. Disp. (bbls)	Loading (lbs)			Removals (lbs)
	Current-Level Effluent	Gas Flotation Effluent	Comm'l Disp'l Effluent				Curr.-Level Effluent	Gas Flot'n Effluent	Comm. Disp Effluent	Incremental
Conventionals										
Oil & Grease	231,688.00	23500	0	69,806	53,751	16,055	5,656	442	0	5,215
Solids, Total Suspended	520,375.00	30000	0	69,806	53,751	16,055	12,704	564	0	12,140
Total Conventionals							**18,361**	**1,006**	**0**	**17,355**
Priority Poll. Organics										
Benzene	1,341.00	1225.91	0	69,806	53,751	16,055	33	23	0	10
Ethylbenzene	1,149.00	62.18	0	69,806	53,751	16,055	28	1	0	27
Toluene	891.00	827.8	0	69,806	53,751	16,055	22	16	0	6
Naphthalene	525.00	92.02	0	69,806	53,751	16,055	13	2	0	11
Phenol	263.00	263.00	0	69,806	53,751	16,055	6	5	0	1
Total P.P. Organics							**102**	**46**	**0**	**55**
Priority Poll. Metals										
Arsenic	166.00	73.08	0	69,806	53,751	16,055	4	1	0	3
Cadmium	26.08	14.47	0	69,806	53,751	16,055	1	0	0	0
Copper	277.20	277.20	0	69,806	53,751	16,055	7	5	0	2
Lead	1,376.00	124.86	0	69,806	53,751	16,055	34	2	0	31
Nickel	115.52	115.52	0	69,806	53,751	16,055	3	2	0	1
Zinc	362.94	133.85	0	69,806	53,751	16,055	9	3	0	6
Total P.P. Metals							**57**	**14**		**43**
Non-Conventionals										
Alumimum	6,468.40	49.93	0	69,806	53,751	16,055	158	1	0	157
Barium	498.10	498.10	0	69,806	53,751	16,055	12	9	0	3
Boron	15,042.00	15,042.00	0	69,806	53,751	16,055	367	283	0	84
Iron	384,412.00	3146.15	0	69,806	53,751	16,055	9,385	59	0	9,326
Manganese	5,146.60	74.16	0	69,806	53,751	16,055	126	1	0	124
Titanium	74.58	4.48	0	69,806	53,751	16,055	2	0	0	2
Total Xylenes	2675	378.01	0	69,806	53,751	16,055	65	7	0	58
Tot. Non-Conventionals							**10,115**	**361**	**0**	**9,754**
Grand Total Pollutant Loadings/Removals							**28,634**	**1,427**	**0**	**27,207**

New Sources
Annual Workover/Treatment Fluids Pollutant Removals
Discharge Option
Medium/Large–Volume Facilities Use Gas Flotation; Small–Volume Facilities Use Commercial Disposal

Print Date: 11–10–94

Pollutant Parameter	Concentration (ug/l)			Vol. Currently Discharged (bbls)	Vol. Using GF (bbls)	Vol. Using Comm. Disp. (bbls)	Loading (lbs)			Removals (lbs)
	Current–Level Effluent	Gas Flotation Effluent	Comm'l Disp'l Effluent				Curr.–Level Effluent	Gas Flot'n Effluent	Comm. Disp Effluent	Incremental
Conventionals										
Oil & Grease	231,688.00	23,500.00	0.00	26,415	20,340	6,075	2,140	167	0	1,973
Solids, Total Suspended	520,375.00	30,000.00	0.00	26,415	20,340	6,075	4,807	213	0	4,594
Total Conventionals							6,948	381	0	6,567
Priority Poll. Organics										
Benzene	1,341.00	1,225.91	0.00	26,415	20,340	6,075	12	9	0	4
Ethylbenzene	1,149.00	62.18	0.00	26,415	20,340	6,075	11	0	0	10
Toluene	891.00	827.80	0.00	26,415	20,340	6,075	8	6	0	2
Naphthalene	525.00	92.02	0.00	26,415	20,340	6,075	5	1	0	4
Phenol	263.00	263.00	0.00	26,415	20,340	6,075	2	2	0	1
Total P.P. Organics							39	18	0	21
Priority Poll. Metals										
Arsenic	166.00	73.08	0.00	26,415	20,340	6,075	2	1	0	1
Cadmium	26.08	14.47	0.00	26,415	20,340	6,075	0	0	0	0
Copper	277.20	277.20	0.00	26,415	20,340	6,075	3	2	0	1
Lead	1,376.00	124.86	0.00	26,415	20,340	6,075	13	1	0	12
Nickel	115.52	115.52	0.00	26,415	20,340	6,075	1	1	0	0
Zinc	362.94	133.85	0.00	26,415	20,340	6,075	3	1	0	2
Total P.P. Metals							21	5	0	16
Non–Conventionals										
Alumimum	6,468.40	49.93	0.00	26,415	20,340	6,075	60	0	0	59
Barium	498.10	498.10	0.00	26,415	20,340	6,075	5	4	0	1
Boron	15,042.00	15,042.00	0.00	26,415	20,340	6,075	139	107	0	32
Iron	384,412.00	3,146.15	0.00	26,415	20,340	6,075	3,551	22	0	3,529
Manganese	5,146.60	74.16	0.00	26,415	20,340	6,075	48	1	0	47
Titanium	74.58	4.48	0.00	26,415	20,340	6,075	1	0	0	1
Total Xylenes	2,675.00	378.01	0.00	26,415	20,340	6,075	25	3	0	22
Tot. Non–Conventionals							3,828	137	0	3,691
Grand Total Pollutant Loadings/Removals							10,835	540	0	10,295

New Sources
Annual Completion Fluids Pollutant Removals
Discharge Option
Medium/Large–Volume Facilities Use Gas Flotation; Small–Volume Facilities Use Commercial Disposal

Print Date: 11–10–94

Pollutant Parameter	Concentration (ug/l)			Vol. Currently Discharged (bbls)	Vol. Using GF (bbls)	Vol. Using Comm. Disp. (bbls)	Loading (lbs)			Removals (lbs)
	Current–Level Effluent	Gas Flotation Effluent	Comm'l Disp'l Effluent				Curr.–Level Effluent	Gas Flot'n Effluent	Comm. Disp Effluent	Incremental
Conventionals										
Oil & Grease	231,688.00	23,500.00	0	9,405	7,242	2,163	762	60	0	703
Solids, Total Suspended	520,375.00	30,000.00	0	9,405	7,242	2,163	1,712	76	0	1,636
Total Conventionals							**2,474**	**136**	**0**	**2,338**
Priority Poll. Organics										
Benzene	1,341.00	1225.91	0	9,405	7,242	2,163	4	3	0	1
Ethylbenzene	1,149.00	62.18	0	9,405	7,242	2,163	4	0	0	4
Toluene	891.00	827.8	0	9,405	7,242	2,163	3	2	0	1
Naphthalene	525.00	92.02	0	9,405	7,242	2,163	2	0	0	1
Phenol	263.00	263.00	0	9,405	7,242	2,163	1	1	0	0
Total P.P. Organics							**14**	**6**	**0**	**7**
Priority Poll. Metals										
Arsenic	166.00	73.08	0	9,405	7,242	2,163	1	0	0	0
Cadmium	26.08	14.47	0	9,405	7,242	2,163	0	0	0	0
Copper	277.20	277.20	0	9,405	7,242	2,163	1	1	0	0
Lead	1,376.00	124.86	0	9,405	7,242	2,163	5	0	0	4
Nickel	115.52	115.52	0	9,405	7,242	2,163	0	0	0	0
Zinc	362.94	133.85	0	9,405	7,242	2,163	1	0	0	1
Total P.P. Metals							**8**	**2**	**0**	**6**
Non–Conventionals										
Alumimum	6,468.40	49.93	0	9,405	7,242	2,163	21	0	0	21
Barium	498.10	498.10	0	9,405	7,242	2,163	2	1	0	0
Boron	15,042.00	15,042.00	0	9,405	7,242	2,163	49	38	0	11
Iron	384,412.00	3146.15	0	9,405	7,242	2,163	1,264	8	0	1,256
Manganese	5,146.60	74.16	0	9,405	7,242	2,163	17	0	0	17
Titanium	74.58	4.48	0	9,405	7,242	2,163	0	0	0	0
Total Xylenes	2675	378.01	0	9,405	7,242	2,163	9	1	0	8
Tot. Non–Conventionals							**1,363**	**49**	**0**	**1,314**
Grand Total Pollutant Loadings/Removals							**3,858**	**192**	**0**	**3,666**

APPENDIX XIII-1

DECK DRAINAGE COMPLIANCE

COST CALCULATIONS

1.0 PRODUCTION OPERATIONS

1.1 Production Facility Capital Costs

Tank and Pump Cost:

Item	Cost
500 bbl Tank	$12,912
(2) Pumps @ $4,000	$8,000
Total Equipment	$20,912
Piping @ 15%[a]	$3,136
Labor @ 32%[a]	$6,692
Transportation @ 5%[a]	$1,046
Total Installation	$31,786
Engineering @ 10%[a]	$3,179
Contingency @ 15%[a]	$4,768
Insurance @ 4%[a]	$1,271
Total Tank & Pump Cost	**$41,004**

Platform Cost:

Platform area = 2 x tank footprint = 2 x ((15 / 2)^2 x pi) + 50) = 453 sq ft

Land-based cost = 453 x $40/sq ft = $18,120

Water-based cost = 453 x $75/sq ft = $33,975

Total Capital Cost (Tank and Platform):

Land-based cost = $18,120 + $41,004 = $59,124

Water-based cost = $33,975 + $41,004 = $74,979

[a] Section XI.3.1

1.2 Production Facility Annual O&M Cost

Injection Onsite (Option 2a):

Land-based O&M Cost = 11,213[b] bpy x ($0.15[c] + $0.01[c]) = $1,794

Water-based O&M Cost = 11,213[b] bpy x ($0.08[c] + $0.01[c]) = $1,009

Gas Flotation Onsite (Option 2b):

Land-based O&M Cost = 11,213[b] bpy x ($0.09[c] + $0.01[c]) = $1,121

Water-based O&M Cost = 11,213[b] bpy x ($0.01[c] + $0.01[c]) = $224

Commercial Disposal (Options 2a and 2b):

Land-based O&M Cost = 11,213[b] bpy x $1.66[b] = $18,614

Water-based O&M Cost = 11,213[b] bpy x $1.63[b] = $18,277

[b] Section 3.2

[c] Section 3.3

2.0 DRILLING OPERATIONS

2.1 Assumptions For Newly Drilled Land-based Wells

- Deck drainage and area runoff will be collected in the cellar and ring leeve ditch.

- The drilling pad area will be 350 ft x 350 ft with a total surface area of 122,500 sq ft. These were the dimensions of the ARCO drilling operation in the Sabine Wildlife Refuge and represent the minimum area requirements (SAIC, August 8, 1994).

- Drilling time will be 30 days. The estimated average drilling time from the Coastal Survey was approximately 20 days (see Table IX-14), however this did not include time to test the well and to plug and abandon or complete the well. The additional 10 days should account for these activities.

- The amount of rainfall is based on the average 30-day rainfall for New Orleans, Louisiana for the year 1993. The total rainfall for 1993 was 52.7 inches (Britton, 1994) which is just 2% lower than the average annual rainfall of 53.7 inches (Miller, 1975). The 30-day average rainfall total is 4.33 inches and is based on the New Orleans 1993 rainfall data.

- Rainwater will be used as make-up for drilling fluids (SAIC, May 1994). The amount used will be equal to the volume of waste mud generated minus the solids content of the mud. The estimated average volume of mud disposed as reported in the Coastal Survey Summary Statistics was 3,038.5 bbls (SAIC, September 30, 1994). The drilling fluid solids content ranged from the below 10% to around 35% by volume at the three sampled drilling operations (SAIC, May 1994; SAIC, August 5, 1994; SAIC, August 8, 1994). A solids content of 35% will be used as a conservative estimate since it will result in a lower volume of deck drainage that is recycled.

2.2 Average Drilling Operation Rainwater Volume Generated For Newly Drilled Land-based Wells

Total Rainfall = Area (sq ft) x Rainfall (ft) x bbls/cu ft

Total Rainfall = 122,500 sq ft x (52.7 in./yr x 30 days / 365 / 12 in/ft) x (7.48 gal/ft^3 / 42 gal/bbl) = 7,876 bbls

Mud Make Up = 3038.5 bbls x (1 - 0.35) = 1,975 bbls

2.3 Estimated Storage and Disposal Cost for Newly Drilled Land-Based Wells

Pump rental	= 30 days x $50/day[a]	= $1,500 per well
Tank rental	= 30 days x $75/day[a]	= $2,250 per well
Disposal Cost	= 1,074[b] bbls x $3.75/bbl[a]	= $4,028 per well
Total deck drainage management cost		= $7,778 per well

This value is an overestimate because some of the wells will elect to use annular injection to dispose of at least a portion of their deck drainage.

[a] See assumptions in Section XIII.4.2

[b] Table XIII-5

2.4 Assumptions For Recompletion and Sidetrack of Existing Land-based Wells

- Table IX-14 shows that for recompletions and sidetracks, the average days to drill were 8.5 and 10.5 or roughly one half the time to drill a new well. Therefore, the amount of rainwater generated is assumed to be one-half that of newly drilled wells (i.e., one-half the average 30-day rainfall; 15 days duration). Although recompletions may use smaller equipment and smaller pads, there is not sufficient information available to estimate the size of the reduction in volume. The 15-day average rainfall total is 2.17 inches and is based on the New Orleans 1993 rainfall data (Britton, 1994).

- Rainwater will be used as make-up water for drilling fluids (SAIC, May 1994). The amount used will be equal to the volume of waste mud generated minus the solids content of the mud. The estimated average volume of mud disposed as reported in the Coastal Survey Summary

Statistics was 1,803 bbls (Note that this volume is close to half the volume reported for newly drilled wells) (SAIC, September 30, 1994). The drilling fluids solids content ranged from the low 20's to around 35% by volume at the three sampled drilling operations (SAIC, May 1994; SAIC, August 5, 1994; SAIC, August 8, 1994). A solid content of 35% will be used as a conservative estimate.

2.5 Average Drilling Operation Rainwater Volume Generated For Land-based Recompletions and Sidetracks

Total Rainfall = Area(sq ft) x Rainfall(ft) x bbls/cu ft

Total Rainfall = 122,500 sq ft x (52.7 in. x 15 days / 365 / 12 in/ft) x (7.48 gal/ft^3 / 42 gal/bbl) = 3,938 bbls

Mud Make Up = 1803 bbls x (1 - 0.35) = 1,172 bbls

2.6 Estimated Storage and Disposal Cost for Land-Based Recompletions and Sidetracks

Pump rental	= 15 days x $50/day[c]	= $750 per well
Tank rental	= 15 days x $75/day[c]	= $1,125 per well
Disposal Cost	= 352[d] x $3.75/bbl[c]	= $1,320 per well
Total deck drainage Management cost		= $3,195 per well

[c] See assumptions in Section XIII.4.2

[d] Table XIII-5

2.7 Estimated Disposal Cost for Newly Drilled Water-Based Wells

Storage Cost	= $150[e] x 30 / 4[f]	= $1,125
Transportation Cost	= $1,000[e] x 2 / 4[f]	= $500
Disposal Cost	= $2.00[e] x 516	= $1,032
Total Cost		= $2,657

[e] See assumptions in Section XIII.4.3

[f] Use of only one of four barge compartments.

2.8 Estimated Storage and Disposal Costs for Water-based Recompletions & Sidetracks

Storage Cost	= $150[g] x 15 / 4[h]	= $563
Transportation Cost	= $1,000[g] x 1 / 4[h]	= $250
Disposal Cost	= $2.00[g] x 567	= $1,134
Total Cost		= $1,947

[g] See assumptions in Section XIII.4.4

[h] Use of only one of four barge compartments.

APPENDIX XIII-2

DECK DRAINAGE VOLULMES FOR LAND-BASED PRODUCTION OPERATIONS

BASED ON 1993 DAILY RAINFALL DATA FOR NEW ORLEANS, LOUISIANA

OPTION 2: CAPTURE OF 500 BBL FIRST FLUSH

Date	Rainfall[a] (inches)	Surface Area (sq ft)	Depth of 500 bbl (inches)	Excess Depth (inches)	Volume Generated (bbl)	Volume Discharged (bbl)	Volume Captured (bbl)
1-3-93	0.01	122,500	0.275	0.000	18	0	18
1-4-93	0.91	122,500	0.275	0.635	1,654	1,154	500
1-7-93	0.85	122,500	0.275	0.575	1,545	1,045	500
1-10-93	1.72	122,500	0.275	1.445	3,127	2,627	500
1-11-93	0.58	122,500	0.275	0.305	1,054	554	500
1-15-93	0.76	122,500	0.275	0.485	1,382	882	500
1-19-93	0.2	122,500	0.275	0.000	364	0	364
1-20-93	0.53	122,500	0.275	0.255	964	464	500
1-24-93	0.25	122,500	0.275	0.000	455	0	455
1-29-93	0.38	122,500	0.275	0.105	691	191	500
1-30-93	0.02	122,500	0.275	0.000	36	0	36
2-5-93	0.23	122,500	0.275	0.000	418	0	418
2-6-93	0.13	122,500	0.275	0.000	236	0	236
2-10-93	0.86	122,500	0.275	0.585	1,564	1,064	500
2-11-93	0.31	122,500	0.275	0.035	564	64	500
2-16-93	0.51	122,500	0.275	0.235	927	427	500
2-25-93	0.3	122,500	0.275	0.025	545	45	500
3-2-93	1.56	122,500	0.275	1.285	2,836	2,336	500
3-3-93	0.04	122,500	0.275	0.000	73	0	73
3-12-93	1.17	122,500	0.275	0.895	2,127	1,627	500
3-16-93	1.61	122,500	0.275	1.335	2,927	2,427	500
3-20-93	0.84	122,500	0.275	0.565	1,527	1,027	500
3-25-93	0.41	122,500	0.275	0.135	745	245	500
3-29-93	0.01	122,500	0.275	0.000	18	0	18
3-30-93	0.01	122,500	0.275	0.000	18	0	15
4-3-93	0.03	122,500	0.275	0.000	55	0	55
4-4-93	1.88	122,500	0.275	1.605	3,418	2,918	500
4-8-93	1.14	122,500	0.275	0.865	2,073	1,573	500
4-14-93	1.23	122,500	0.275	0.955	2,236	1,736	500
4-15-93	0.09	122,500	0.275	0.000	164	0	164
4-20-93	0.26	122,500	0.275	0.000	473	0	473
4-25-93	0.01	122,500	0.275	0.000	18	0	18
4-26-93	0.02	122,500	0.275	0.000	36	0	36
4-30-93	2.16	122,500	0.275	1.885	3,927	3,427	500
5-1-93	2.2	122,500	0.275	1.925	4,000	3,500	500
5-2-93	0.1	122,500	0.275	0.000	182	0	182
5-9-93	0.18			0.000	327	0	327
5-10-93	0.61	122,500	0.275	0.335	1,109	609	500
5-11-93	0.57	122,500	0.275	0.295	1,036	536	500
5-12-93	0.06	122,500	0.275	0.000	109	0	109
5-19-93	0.03	122,500	0.275	0.000	55	0	55
5-24-93	0.84	122,500	0.275	0.565	1,527	1,027	500
5-26-93	2.63	122,500	0.275	2.355	4,781	4,281	500
5-29-93	0.01	122,500	0.275	0.000	18	0	18
6-11-93	1.36	122,500	0.275	1.085	2,473	1,973	500
6-16-93	0.04	122,500	0.275	0.000	73	0	73
6-17-93	0.09	122,500	0.275	0.000	164	0	164
6-18-93	0.58	122,500	0.275	0.305	1,054	554	500
6-20-93	0.71	122,500	0.275	0.435	1,291	791	500
6-21-93	0.14	122,500	0.275	0.000	255	0	255

Date	Rainfall[a] (inches)	Surface Area (sq ft)	Depth of 500 bbl (inches)	Excess Depth (inches)	Volume Generated (bbl)	Volume Discharged (bbl)	Volume Captured (bbl)
6-22-93	0.93	122,500	0.275	0.655	1,691	1,191	500
6-23-93	0.04	122,500	0.275	0.000	73	0	73
6-24-93	0.58	122,500	0.275	0.305	1,054	554	500
6-27-93	0.48	122,500	0.275	0.205	873	373	500
6-28-93	0.01	122,500	0.275	0.000	18	0	18
7-4-93	0.07	122,500	0.275	0.000	127	0	127
7-8-93	0.19	122,500	0.275	0.000	345	0	345
7-9-93	0.12	122,500	0.275	0.000	218	0	218
7-10-93	0.15	122,500	0.275	0.000	273	0	273
7-11-93	0.53	122,500	0.275	0.255	964	464	500
7-12-93	0.05	122,500	0.275	0.000	91	0	91
7-13-93	1.62	122,500	0.275	1.345	2,945	2,445	500
7-15-93	0.09	122,500	0.275	0.000	164	0	164
7-20-93	1.62	122,500	0.275	1.345	2,945	2,445	500
7-21-93	0.73	122,500	0.275	0.455	1,327	827	500
7-22-93	0.54	122,500	0.275	0.265	982	482	500
7-25-93	0.06	122,500	0.275	0.000	109	0	109
8-1-93	0.05	122,500	0.275	0.000	91	0	91
8-2-93	0.01	122,500	0.275	0.000	18	0	18
8-3-93	0.04	122,500	0.275	0.000	73	0	73
8-4-93	0.42	122,500	0.275	0.145	764	264	500
8-6-93	0.16	122,500	0.275	0.000	291	0	291
8-7-93	0.2	122,500	0.275	0.000	364	0	364
8-8-93	0.13	122,500	0.275	0.000	236	0	236
8-14-93	0.25	122,500	0.275	0.000	455	0	455
8-15-93	0.14	122,500	0.275	0.000	255	0	255
8-20-93	0.32	122,500	0.275	0.045	582	82	500
8-21-93	0.11	122,500	0.275	0.000	200	0	200
8-22-93	0.06	122,500	0.275	0.000	109	0	109
8-26-93	0.09	122,500	0.275	0.000	164	0	164
8-27-93	0.17	122,500	0.275	0.000	309	0	309
8-30-93	0.11	122,500	0.275	0.000	200	0	200
9-5-93	0.36	122,500	0.275	0.085	655	155	500
9-6-93	0.36	122,500	0.275	0.085	655	155	500
9-7-93	0.52	122,500	0.275	0.245	945	445	500
9-10-93	0.35	122,500	0.275	0.075	636	136	500
9-14-93	0.07	122,500	0.275	0.000	127	0	127
9-15-93	0.5	122,500	0.275	0.225	909	409	500
9-18-93	0.26	122,500	0.275	0.000	473	0	473
9-22-93	0.04	122,500	0.275	0.000	73	0	73
9-27-93	0.01	122,500	0.275	0.000	18	0	18
10-13-93	0.14	122,500	0.275	0.000	255	0	255
10-21-93	0.56	122,500	0.275	0.285	1,018	518	500
10-22-93	0.01	122,500	0.275	0.000	18	0	18
10-23-93	0.09	122,500	0.275	0.000	164	0	164
10-25-93	0.03	122,500	0.275	0.000	55	0	55
10-29-93	2.66	122,500	0.275	2.385	4,836	4,336	500
10-30-93	0.18	122,500	0.275	0.000	327	0	327
11-4-93	0.11	122,500	0.275	0.000	200	0	200
11-5-93	0.41	122,500	0.275	0.135	745	245	500

Date	Rainfall[a] (inches)	Surface Area (sq ft)	Depth of 500 bbl (inches)	Excess Depth (inches)	Volume Generated (bbl)	Volume Discharged (bbl)	Volume Captured (bbl)
11-8-93	0.01	122,500	0.275	0.000	18	0	18
11-9-93	0.47	122,500	0.275	0.195	854	354	500
11-15-93	0.92	122,500	0.275	0.645	1,673	1,173	500
11-16-93	0.03	122,500	0.275	0.000	55	0	55
11-17-93	0.31	122,500	0.275	0.035	564	64	500
11-27-93	0.17	122,500	0.275	0.000	309	0	309
12-4-93	0.67	122,500	0.275	0.395	1,218	718	500
12-10-93	0.34	122,500	0.275	0.065	618	118	500
12-13-93	0.91	122,500	0.275	0.635	1,654	1,154	500
12-19-93	0.07	122,500	0.275	0.000	127	0	127
12-20-93	0.33	122,500	0.275	0.055	600	100	500
12-22-93	0.51	122,500	0.275	0.235	927	427	500
12-28-93	0.03	122,500	0.275	0.000	55	0	55
12-29-93	0.04	122,500	0.275	0.000	73	0	73
Total	52.71				95,830	58,740	37,090
30-day Volume					7,876	4,828	3,049
15-day Volume					3,938	2,414	1,524

[a] Source, Britton, 1994

APPENDIX XIII-3

DECK DRAINAGE POLLUTANT LOADING AND REDUCTION CALCULATIONS

APPENDIX XIII-3
TABLE 1
Annual Production Operation Deck Drainage Pollutant Loading Characterization for the Gulf of Mexico
Option 2A: Zero Discharge of First Flush

Pollutant Parameter	Concentration (ug/l) Treated Effluent			Volume Discharged (bbl) Current Level	Volume Discharged (bbl) Option 2A Level	Loading (pounds) Current Level Effluent			Loading (pounds) Option 2A Level Effluent			Loading (pounds) Incremental Current to Option 2A		
Oil & Grease	12,000.0	–	1,310,000.0	7,995,527	295,953	33,556	–	3,663,163	1,242	–	135,591	32,314	–	3,527,572
TSS	37,200.0	–	220,400.0	7,995,527	295,953	104,023	–	616,306	3,850	–	22,812	100,172	–	593,494
Total Conventional						137,578	–	4,279,469	5,092	–	158,404	132,486	–	4,121,065
Beryllium	0.5	–	1.0	7,995,527	295,953	1	–	3	0	–	0	1	–	3
Cadmium	2.0	–	25.0	7,995,527	295,953	6	–	70	0	–	3	5	–	67
Chromium	5.0		0.5	7,995,527	295,953	14	–	1	1	–	0	13	–	1
Copper	14.0	–	219.0	7,995,527	295,953	39	–	612	1	–	23	38	–	590
Lead	25.0	–	352.0	7,995,527	295,953	70	–	984	3	–	36	67	–	948
Nickel	15.0	–	75.0	7,995,527	295,953	42	–	210	2	–	8	40	–	202
Selenium	1.5	–	47.5	7,995,527	295,953	4	–	133	0	–	5	4	–	128
Zinc	2,970.0	–	6,980.0	7,995,527	295,953	8,305	–	19,518	307	–	722	7,998	–	18,796
Total P.P. Metals						8,481	–	21,532	314	–	797	8,167	–	20,735
Benzene	0.0	–	205.0	7,995,527	295,953	0	–	573	0	–	21	0	–	552
Methylene Chloride	0.0	–	874.0	7,995,527	295,953	0	–	2,444	0	–	90	0	–	2,354
Naphthalene	392.0	–	3,144.0	7,995,527	295,953	1,096	–	8,792	41	–	325	1,056	–	8,466
Toluene	0.0	–	260.0	7,995,527	295,953	0	–	727	0	–	27	0	–	700
1,1-Dichloroethene	0.0	–	26.0	7,995,527	295,953	0	–	73	0	–	3	0	–	70
Total P.P. Organics						1,096	–	12,609	41	–	467	1,056	–	12,142
Alumimum	176.0	–	23,100.0	7,995,527	295,953	492	–	64,595	18	–	2,391	474	–	62,204
Barium	2,420.0	–	20,500.0	7,995,527	295,953	6,767	–	57,324	250	–	2,122	6,517	–	55,202
Boron	3,110.0	–	19,300.0	7,995,527	295,953	8,697	–	53,969	322	–	1,998	8,375	–	51,971
Calcium	98,200.0	–	341,000.0	7,995,527	295,953	274,597	–	953,541	10,164	–	35,295	264,433	–	918,246
Iron	830.0	–	81,300.0	7,995,527	295,953	2,321	–	227,340	86	–	8,415	2,235	–	218,925
Manganese	133.0	–	919.0	7,995,527	295,953	372	–	2,570	14	–	95	358	–	2,475
Magnesium	50,400.0	–	219,000.0	7,995,527	295,953	140,934	–	612,391	5,217	–	22,668	135,717	–	589,724
Molybdenum	5.0	–	20.0	7,995,527	295,953	14	–	56	1	–	2	13	–	54
Sodium	1,510,000.0	–	5,680,000.0	7,995,527	295,953	4,222,425	–	15,883,027	156,292	–	587,907	4,066,132	–	15,295,120
Titanium	4.0	–	2,030.0	7,995,527	295,953	11	–	5,677	0	–	210	11	–	5,466
Vanadium	7.5	–	92.0	7,995,527	295,953	21	–	257	1	–	10	20	–	248
Yttrium	1.0	–	17.0	7,995,527	295,953	3	–	48	0	–	2	3	–	46
Acetone	0.0	–	852.0	7,995,527	295,953	0	–	2,382	0	–	88	0	–	2,294
m-Xylene	0.0	–	47.0	7,995,527	295,953	0	–	131	0	–	5	0	–	127
N-octadecane	0.0	–	106.0	7,995,527	295,953	0	–	296	0	–	11	0	–	285
o,p-Xylene	105.0	–	195.0	7,995,527	295,953	294	–	545	11	–	20	283	–	525
Total Non-Conv.						4,656,947	–	17,864,150	172,376	–	661,238	4,484,571	–	17,202,912

DDPRLOA4.WK3

Shaded values are reported as one half the detection limit
or as zero where the detection limit was not available

Appendix XIII–3
TABLE 2
Annual Production Operation Deck Drainage Pollutant Loading Characterization for the Gulf of Mexico
Option 2b: Gas Flotation Treatment of First Flush

Pollutant Parameter	Concentration (ug/l) Treated Effluent Settling			Concentration (ug/l) Treated Effluent Flotation*	Volume Discharged (bbl) Current Level	Volume Discharged (bbl) Option 2B Excess (e)	Loading (pounds) Current Level Effluent			Loading (pounds) Option 2B Level Effluent (a)				Loading (pounds) Incremental Current to Option 2B		
Oil & Grease	12,000.0	–	1,310,000.0	23.5	7,995,527	295,953	33,556	–	3,663,163	1,305	–	135,655	d	32,250	–	3,527,508
TSS	37,200.0	–	220,400.0	30	7,995,527	295,953	104,023	–	616,306	3,931	–	22,893	d	100,091	–	593,413
Total Conventional							137,578		4,279,469	5,237	–	158,548		132,342	–	4,120,921
Cadmium	2.0	–	25.0	14.47	7,995,527	295,953	6	–	70	6	–	42	c	0	–	28
Copper	14.0	–	219.0	284.58	7,995,527	295,953	39	–	612	39	–	612	b	0	–	0
Lead	25.0	–	352.0	124.86	7,995,527	295,953	70	–	984	70	–	373	c	0	–	612
Nickel	15.0	–	75.0	1091.49	7,995,527	295,953	42	–	210	42	–	210	b	0	–	0
Zinc	2,970.0	–	6,980.0	133.85	7,995,527	295,953	8,305	–	19,518	668	–	1,083	d	7,637	–	18,435
Total P.P. Metals							8,462	–	21,395	824	–	2,319		7,637	–	19,075
Benzene	0.0	–	205.0	1225.91	7,995,527	295,953	0	–	573	0	–	573	b	0	–	0
Naphthalene	392.0	–	3,144.0	92.02	7,995,527	295,953	1,096	–	8,792	288	–	573	d	808	–	8,218
Toluene	0.0	–	260.0	827.8	7,995,527	295,953	0	–	727	0	–	727	b	0	–	0
Total P.P. Organics							1,096	–	10,092	288	–	1,873		808	–	8,218
Alumimum	176.0	–	23,100.0	49.93	7,995,527	295,953	492	–	64,595	153	–	2,525	d	339	–	62,069
Barium	2,420.0	–	20,500.0	35560.83	7,995,527	295,953	6,767	–	57,324	6,767	–	57,324	b	0	–	0
Boron	3,110.0	–	19,300.0	16473.76	7,995,527	295,953	8,697	–	53,969	8,697	–	46,358	c	0	–	7,611
Iron	830.0	–	81,300.0	3146.15	7,995,527	295,953	2,321	–	227,340	2,321	–	16,887	c	0	–	210,453
Manganese	133.0	–	919.0	74.16	7,995,527	295,953	372	–	2,570	213	–	295	d	158	–	2,275
Titanium	4.0	–	2,030.0	4.48	7,995,527	295,953	11	–	5,677	11	–	222	c	0	–	5,454
Total Xylenes	105.0	–	242.0	378.01	7,995,527	295,953	294	–	677	294	–	677	b	0	–	0
Total Non–Conv.							18,953	–	412,151	18,455	–	124,289		498	–	287,862

DDPRLDG3.WK3

Notes:

Shaded values are reported as one half the detection limit
or as zero where the detection limit was not available

a: Combined loading of first flush volume treated by flotation and excess volume treated by settling.

b: Flotation effluent concentration exceeded settling effluent concentrations,
used settling effluent concentrations for all discharges.

c: Flotation effluent concentration fell between settling effluent min. and max. concentrations,
for flotation effluent, settling effluent min. concentration was used for flotation effluent min.
and the flotation effluent concentration was used for the max. concentration.

d: Flotation effluent concentration was below settling effluent min. concentration,
flotation effluent concentration was used for both min. and max. flotation values.

e: Volume not captured in first flush.

APPENDIX XIII-3
TABLE 3
Annual Drilling Operation Deck Drainage Pollutant Loading Characterization for the Gulf of Mexico
Option 2C: Zero Discharge of First Flush

Pollutant Parameter	Concentration (ug/l) Treated Effluent			Volume Discharged (bbl) Current Level	Volume Discharged (bbl) Option 2C Level	Loading (pounds) Current Level Effluent			Loading (pounds) Option 2C Level Effluent			Loading (pounds) Incremental Current to Option 2C		
Oil & Grease	12,000.0	–	1,310,000.0	1,186,934	615,973	4,981	–	543,796	2,585	–	282,209	2,396	–	261,587
TSS	37,200.0	–	220,400.0	1,186,934	615,973	15,442	–	91,491	8,014	–	47,480	7,428	–	44,010
Total Conventional						20,423	–	635,286	10,599	–	329,689	9,824	–	305,597
Beryllium	0.5	–	1.0	1,186,934	615,973	0	–	0	0	–	0	0	–	0
Cadmium	2.0	–	25.0	1,186,934	615,973	1	–	10	0	–	5	0	–	5
Chromium	5.0		0.5	1,186,934	615,973	2	–	0	1	–	0	1	–	0
Copper	14.0	–	219.0	1,186,934	615,973	6	–	91	3	–	47	3	–	44
Lead	25.0	–	352.0	1,186,934	615,973	10	–	146	5	–	76	5	–	70
Nickel	15.0	–	75.0	1,186,934	615,973	6	–	31	3	–	16	3	–	15
Selenium	1.5	–	47.5	1,186,934	615,973	1	–	20	0	–	10	0	–	9
Zinc	2,970.0	–	6,980.0	1,186,934	615,973	1,233	–	2,897	640	–	1,504	593	–	1,394
Total P.P. Metals						1,259	–	3,196	653	–	1,659	606	–	1,538
Benzene	0.0	–	205.0	1,186,934	615,973	0	–	85	0	–	44	0	–	41
Methylene Chloride	0.0	–	874.0	1,186,934	615,973	0	–	363	0	–	188	0	–	175
Naphthalene	392.0	–	3,144.0	1,186,934	615,973	163	–	1,305	84	–	677	78	–	628
Toluene	0.0	–	260.0	1,186,934	615,973	0	–	108	0	–	56	0	–	52
1,1-Dichloroethene	0.0	–	26.0	1,186,934	615,973	0	–	11	0	–	6	0	–	5
Total P.P. Organics						163	–	1,872	84	–	971	78	–	900
Alumimum	176.0	–	23,100.0	1,186,934	615,973	73	–	9,589	38	–	4,976	35	–	4,613
Barium	2,420.0	–	20,500.0	1,186,934	615,973	1,005	–	8,510	521	–	4,416	483	–	4,094
Boron	3,110.0	–	19,300.0	1,186,934	615,973	1,291	–	8,012	670	–	4,158	621	–	3,854
Calcium	98,200.0	–	341,000.0	1,186,934	615,973	40,764	–	141,553	21,155	–	73,461	19,609	–	68,092
Iron	830.0	–	81,300.0	1,186,934	615,973	345	–	33,749	179	–	17,514	166	–	16,234
Manganese	133.0	–	919.0	1,186,934	615,973	55	–	381	29	–	198	27	–	184
Magnesium	50,400.0	–	219,000.0	1,186,934	615,973	20,922	–	90,909	10,858	–	47,178	10,064	–	43,731
Molybdenum	5.0	–	20.0	1,186,934	615,973	2	–	8	1	–	4	1	–	4
Sodium	1,510,000.0	–	5,680,000.0	1,186,934	615,973	626,818	–	2,357,831	325,294	–	1,223,624	301,524	–	1,134,208
Titanium	4.0	–	2,030.0	1,186,934	615,973	2	–	843	1	–	437	1	–	405
Vanadium	7.5	–	92.0	1,186,934	615,973	3	–	38	2	–	20	1	–	18
Yttrium	1.0	–	17.0	1,186,934	615,973	0	–	7	0	–	4	0	–	3
Acetone	0.0	–	852.0	1,186,934	615,973	0	–	354	0	–	184	0	–	170
m-Xylene	0.0	–	47.0	1,186,934	615,973	0	–	20	0	–	10	0	–	9
N-octadecane	0.0	–	106.0	1,186,934	615,973	0	–	44	0	–	23	0	–	21
o,p-Xylene	105.0	–	195.0	1,186,934	615,973	44	–	81	23	–	42	21	–	39
Total Non-Conv.						691,323	–	2,651,929	358,770	–	1,376,249	332,553	–	1,275,680

DDDRLLOA4.WK3

Shaded values are reported as one half the detection limit
or as zero where the detection limit was not available

APPENDIX XIII–3
TABLE 4
Annual Deck Drainage Pollutant Loading Characterization for Cook Inlet, Alaska
Option 2A: Zero Discharge of First Flush!

Pollutant Parameter	Concentration (ug/l) Treated Effluent			Volume Discharged (bbl) Current Level	Volume Discharged (bbl) Option 2A Level	Loading (pounds) Current Level Effluent			Loading (pounds) Option 2A Level Effluent			Loading (pounds) Incremental Current to Option 2A		
Oil & Grease	12,000.0	–	1,310,000.0	235,782	0	990	–	108,024	0	–	0	990	–	108,024
TSS	37,200.0	–	220,400.0	235,782	0	3,068	–	18,174	0	–	0	3,068	–	18,174
Total Conventional						4,057	–	126,198	0	–	0	4,057	–	126,198
Beryllium	0.5	–	1.0	235,782	0	0	–	0	0	–	0	0	–	0
Cadmium	2.0	–	25.0	235,782	0	0	–	2	0	–	0	0	–	2
Chromium	5.0		0.5	235,782	0	0	–	0	0	–	0	0	–	0
Copper	14.0	–	219.0	235,782	0	1	–	18	0	–	0	1	–	18
Lead	25.0	–	352.0	235,782	0	2	–	29	0	–	0	2	–	29
Nickel	15.0	–	75.0	235,782	0	1	–	6	0	–	0	1	–	6
Selenium	1.5	–	47.5	235,782	0	0	–	4	0	–	0	0	–	4
Zinc	2,970.0	–	6,980.0	235,782	0	245	–	576	0	–	0	245	–	576
Total P.P. Metals						250	–	635	0	–	0	250	–	635
Benzene	0.0	–	205.0	235,782	0	0	–	17	0	–	0	0	–	17
Methylene Chloride	0.0	–	874.0	235,782	0	0	–	72	0	–	0	0	–	72
Naphthalene	392.0	–	3,144.0	235,782	0	32	–	259	0	–	0	32	–	259
Toluene	0.0	–	260.0	235,782	0	0	–	21	0	–	0	0	–	21
1,1–Dichloroethene	0.0	–	26.0	235,782	0	0	–	2	0	–	0	0	–	2
Total P.P. Organics						32	–	372	0	–	0	32	–	372
Alumimum	176.0	–	23,100.0	235,782	0	15	–	1,905	0	–	0	15	–	1,905
Barium	2,420.0	–	20,500.0	235,782	0	200	–	1,690	0	–	0	200	–	1,690
Boron	3,110.0	–	19,300.0	235,782	0	256	–	1,591	0	–	0	256	–	1,591
Calcium	98,200.0	–	341,000.0	235,782	0	8,098	–	28,119	0	–	0	8,098	–	28,119
Iron	830.0	–	81,300.0	235,782	0	68	–	6,704	0	–	0	68	–	6,704
Manganese	133.0	–	919.0	235,782	0	11	–	76	0	–	0	11	–	76
Magnesium	50,400.0	–	219,000.0	235,782	0	4,156	–	18,059	0	–	0	4,156	–	18,059
Molybdenum	5.0	–	20.0	235,782	0	0	–	2	0	–	0	0	–	2
Sodium	1,510,000.0	–	5,680,000.0	235,782	0	124,516	–	468,378	0	–	0	124,516	–	468,378
Titanium	4.0	–	2,030.0	235,782	0	0	–	167	0	–	0	0	–	167
Vanadium	7.5	–	92.0	235,782	0	1	–	8	0	–	0	1	–	8
Yttrium	1.0	–	17.0	235,782	0	0	–	1	0	–	0	0	–	1
Acetone	0.0	–	852.0	235,782	0	0	–	70	0	–	0	0	–	70
m–Xylene	0.0	–	47.0	235,782	0	0	–	4	0	–	0	0	–	4
N–octadecane	0.0	–	106.0	235,782	0	0	–	9	0	–	0	0	–	9
o,p–Xylene	105.0	–	195.0	235,782	0	9	–	16	0	–	0	9	–	16
Total Non–Conv.						137,330	–	526,800	0	–	0	137,330	–	526,800

CIOP2A.WK3

Shaded values are reported as one half the detection limit
or as zero where the detection limit was not available

APPENDIX XIII-3
TABLE 5
Annual Deck Drainage Pollutant Loading Characterization for Cook Inlet, Alaska
Option 2B: Gas Flotation Treatment of First Flush

Pollutant Parameter	Concentration (ug/l) Treated Effluent Settling			Concentration (ug/l) Treated Effluent Flotation	Volume Discharged (bbl) Current Level	Volume Discharged (bbl) Option 2B Level	Loading (pounds) Current Level Effluent			Loading (pounds) Option 2B Effluent				Loading (pounds) Incremental Current to Option 2B		
Oil & Grease	12,000.0	–	1,310,000.0	23.5	235,782	235,782	990	–	108,024	2	–	2		988	–	108,022
TSS	37,200.0	–	220,400.0	30	235,782	235,782	3,068	–	18,174	2	–	2		3,065	–	18,172
Total Conventional							4057	–	126198	4	–	4		4053	–	126194
Cadmium	2.0	–	25.0	14.47	235,782	235,782	0	–	2	1	–	1	b	(1)	–	1
Copper	14.0	–	219.0	284.58	235,782	235,782	1	–	18	23	–	23	a	(22)	–	(5)
Lead	25.0	–	352.0	124.86	235,782	235,782	2	–	29	10	–	10	b	(8)	–	19
Nickel	15.0	–	75.0	1091.49	235,782	235,782	1	–	6	90	–	90	a	(89)	–	(84)
Zinc	2,970.0	–	6,980.0	133.85	235,782	235,782	245	–	576	11	–	11		234	–	565
Total P.P. Metals							250	–	631	136	–	136		114	–	495
Benzene	0.0	–	205.0	1225.91	235,782	235,782	0	–	17	101	–	101	a	(101)	–	(84)
Naphthalene	392.0	–	3,144.0	92.02	235,782	235,782	32	–	259	8	–	8		25	–	252
Toluene	0.0	–	260.0	827.8	235,782	235,782	0	–	21	68	–	68	a	(68)	–	(47)
Total P.P. Organics							32	–	298	177	–	177		(145)	–	121
Alumimum	176.0	–	23,100.0	49.93	235,782	235,782	15	–	1,905	4	–	4		10	–	1,901
Barium	2,420.0	–	20,500.0	35560.83	235,782	235,782	200	–	1,690	2,932	–	2,932	a	(2,733)	–	(1,242)
Boron	3,110.0	–	19,300.0	16473.76	235,782	235,782	256	–	1,591	1,358	–	1,358	b	(1,102)	–	233
Iron	830.0	–	81,300.0	3146.15	235,782	235,782	68	–	6,704	259	–	259	b	(191)	–	6,445
Manganese	133.0	–	919.0	74.16	235,782	235,782	11	–	76	6	–	6		5	–	70
Titanium	4.0	–	2,030.0	4.48	235,782	235,782	0	–	167	0	–	0	b	(0)	–	167
Total Xylenes	105.0	–	242.0	378.01	235,782	235,782	9	–	20	31	–	31	a	(23)	–	(11)
Total Non-Conv.							559	–	12,154	4,592	–	4,592		(4,033)	–	7,562

CIOP2B.WK3

Notes:

Shaded values are reported as one half the detection limit
or as zero where the detection limit was not available

a: Flotation effluent concentration exceeded settling effluent concentrations,
resulting in zero pollutant reductions.

b: Flotation effluent concentration fell between settling effluent min. and max. concentrations,
for flotation effluent, resulting in zero pollutant reductions for minimum values.

APPENDIX XVI-1

NWQI Spreadsheets for Cook Inlet Drilling Wastes

AIREDAK3.WK3
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COASTAL OIL AND GAS
DRILLING WASTE - COOK INLET ZERO DISCHARGE BASED ON COMBINED LANDFILL\INJECTION
FUEL USAGE, HORSEPOWER REQUIREMENTS, AND AIR EMISSIONS
AIR EMISSION FACTORS GOTO C209
TOTAL FUEL USAGE & EMISSIONS GOTO A245

DRILLING WASTE VOLUME

Drilling Operation	Total Volume Drilling Waste (bbls)	Muds & Cuttings Per Well (bbls)	Number of Wells	Number of Wells Disposed at Landfill	Number of Wells Disposed Via Injection Well	Volume of Boxes (bbls)	Number of Boxes per Well
New Well	511,577 (a)	14,210	36 (a)	27	9	8	1,776.31
Recompletion	41,269 (a)	2,172	19 (a)	18	1	8	271.51
Total	552,846						

SUPPLY BOAT TRANSIT FUEL CONSUMPTION

Drilling Operation	Number of Boxes per Boat	Proportion of Well Waste Volume per Box	Number of Well Waste Volumes Per Boat	Total Wells	Number of Boat Trips	Miles Per Boat Trip	Total Boat Miles	Average Boat Speed (mi/hr)	Diesel Usage Rate (gal/hr)	Total Diesel Usage (gal)
New Well	227 (b)	0.000563	0.1278	27	211.28	50 (c)	10,564	11.5 (d)	130 (e)	119,419
Recompletion	227 (b)	0.003683	0.8361	18	21.53	50 (c)	1,076	11.5 (d)	130 (e)	12,169
Total										131,587

BARGE TRANSIT FUEL CONSUMPTION

Drilling Operation	Number of Boxes per Barge	Proportion of Well Waste Volume per Box	Number of Well Waste Volumes Per Barge	Total Wells	Number of Barge Trips	Miles Per Barge Trip	Total Barge Miles	Average Barge Speed (mi/hr)	Diesel Usage Rate (gal/hr)	Total Diesel Usage (gal)
New Well	340 (b)	0.000563	0.1914	27	141.06	50 (f)	7,053	6 (g)	24 (h)	28,212
Recompletion	340 (b)	0.003683	1.2523	18	14.37	50 (f)	719	6 (g)	24 (h)	2,875
Total										31,087

SUPPLY BOAT MANEUVERING FUEL CONSUMPTION

Drilling Operation	Total Number of Boat Trips	Manuvering Time Per Trip (hrs)	Diesel Usage Rate (gal/hr)	Total Fuel Consumption (gal)
New Well	211.28	1 (i)	25.3 (i)	5,345
Recompletion	21.53	1 (i)	25.3 (i)	545
Total				5,890

SUPPLY BOAT LOADING FUEL CONSUMPTION

Drilling Operation	Total Number of Boat Trips	Loading Time Per Trip (hrs)	Diesel Usage Rate (gal/hr)	Total Fuel Consumption (gal)
New Well	211.28	5.7 (j)	25.3 (k)	30,335
Recompletion	21.53	5.7 (j)	25.3 (k)	3,091
Total				33,426

SUPPLY BOAT AUXILIARY ELECTRICAL GENERATOR

Drilling Operation	Total Number of Boat Trips	Generator Hours Per Trip	Diesel Usage Rate (gal/hr)	Total Fuel Consumption (gal)	Generator Power Rating (hp)	Total Generator Horsepower-Hours
New Well	211.28	24 (l)	6 (l)	30,424	60 (l)	304241.8
Recompletion	21.53	24 (l)	6 (l)	3,100	60 (l)	31001.98
Total				33,524		335243.8

SUPPLY BOAT CRANES

Drilling Operation	Number of Crane Lifts (drillsite)	Number of Crane Lifts (in port)	Total Crane Lifts Per Round Trip	Number of Crane lifts Per Hour	Crane lift Hours Per Round Trip	Total Number of Boat Trips	Total Crane Hours	Diesel Usage Rate (gal/hr)	Total Fuel Consumption (gal)	Crane Brake Horsepower (bhp)	Total Crane Brake Horsepower - Hours
New Well	56.8 (m)	56.8 (m)	113.5	10 (n)	11.35	211.28	2,398	8.33 (o)	19,975	136 (n)	326130.3
Recompletion	56.8 (m)	56.8 (m)	113.5	10 (n)	11.35	21.53	244	8.33 (o)	2,035	136 (n)	33232.41
Total									22,011		359362.7

BARGE CRANES

Drilling Operation	Number of Crane Lifts (loading)	Number of Crane Lifts (unloading)	Total Crane Lifts Per Round Trip	Number of Crane lifts Per Hour	Crane lift Hours Per Round Trip	Total Number of Boat Trips	Total Crane Hours	Diesel Usage Rate (gal/hr)	Total Fuel Consumption (gal)	Crane Brake Horsepower (bhp)	Total Crane Brake Horsepower - Hours
New Well	34 (p)	34	68	10 (n)	6.8	141.06	959.2	8.33 (o)	7,990	136 (n)	130452.1
Recompletion	34 (p)	34	68	10 (n)	6.8	14.37	97.7	8.33 (o)	814	136 (n)	13292.96
Total									8,804		143745.1

TRUCKS

Drilling Operation	Boxes Per Truck (bbls)	Proportion of Well Waste Volume per Box	Number of Well Waste Volumes per Truck	Total Wells	Total Number of Truck Trips	Miles per Truck Trip	Total Truck Miles	Diesel Usage Rate (miles/gal)	Total Fuel Consumption (gal)
New Well	12 (b)	0.000563	0.006756	27	3,997	10 (q)	39,967	4 (r)	9,992
Recompletion	12 (b)	0.003683	0.044198	18	407	10 (q)	4,073	4 (r)	1,018
Total					4,404		44,040		11,010

WHEEL TRACTOR AT LANDFILL

Drilling Operation	Total Wells	Tractor Time Per Well (hrs)	Total Tractor Time (hrs)	Diesel Usage Rate (gal/hr)	Total Fuel Consumption (gal)
New Well	27	8 (a)	216	1.67 (a)	361
Recompletion	18	8 (a)	144	1.67 (a)	240
Total			360		601

TRACK-TYPE DOZER/LOADER AT LANDFARM

Drilling Operation	Total Wells	Dozer Time Per Well (hrs)	Total Dozer Time (hrs)	Diesel Usage Rate (gal/hr)	Total Fuel Consumption (gal)
New Well	27	16 (a)	432	22 (a)	9,504
Recompletion	18	16 (a)	288	22 (a)	6,336
Total			720		15,840

CUTTINGS GRINDING AND MUDS/CUTTINGS INJECTION AT DRILLSITE

Drilling Operation	Total Well Equivilants	Grinding & Processing HP Requirements	Injection HP Requirements	Process Equipment Operation Hours Per Well	Process Equipment Total Hp-hrs	Process Equip Fuel Usage (scf nat'l gas)	Injection Equipment Operation Hours Per Well	Injection Equipment Total Hp-hrs	Injection Equip Fuel Usage (scf nat'l gas)	Total Hp-hrs
New Well	9	747 (t)	500 (t)	733 (t)	4927959	46815611	47.37 (a)	213,157	2024992	5141116
Recompletion	1	747 (t)	500 (t)	240 (t)	179280	1703160	7.24 (a)	3,620	34391	182900.1
Total					5107239	48518771		216,777	2059383	5324016

AIR EMISSION FACTORS

08-Nov-94

Category	Units	NOx	TSC	SO2	CO	TSP
DIESEL						
Supply Boats						
Transit	(lb/1000 gal)	391.700	16.800	28.480	78.300	33.000
Maneuvering	(lb/1000 gal)	419.600	22.600	28.480	59.800	33.000
Idling	(lb/1000 gal)	419.600	22.600	28.480	59.800	33.000
Demurrage (aux gen)	(g/bhp-hr)	14.000	1.120	0.931	3.030	1.000
Barge						
Transit	(lb/1000 gal)	391.700	16.800	28.480	78.300	33.000
Cranes						
Drill Site	(g/bhp-hr)	14.000	1.120	0.931	3.030	1.000
In-Port	(g/bhp-hr)	14.000	1.120	0.931	3.030	1.000
Trucks	(g/mile)	11.440	2.530	NA	8.670	NA
Wheel Tractor	(lb/hr)	1.269	0.188	0.090	3.590	0.136
Dozer/Loader	(lb/hr)	0.827	0.098	0.076	0.201	0.058
NATURAL GAS						
Gas-fired Turbine	(g/hp-hr)	1.700	0.055	0.002	0.050	NA

REFERENCE:
Non-Water Quality Environmental Impacts Resulting From the Onshore Disposal of Drilling Fluids and Drill Cuttings from Offshore Oil and Gas Drilling Activities," US EPA, January 13, 1993, p. D-22.

TOTAL AIR EMISSIONS – ZERO DISCHARGE BASED ON COMBINED OPTION

08-Nov-96

Category	Total Diesel Fuel Usage (1000 gal)	Natural Gas Usage (1000scf)	Power Requirements (hp-hr)	Nox Total (lbs)	THC Total (lbs)	SO2 Total (lbs)	CO Total (lbs)	TSP Total (lbs)
DIESEL								
Supply Boats								
Transit	131.59	NA	NA	51,542.72	2,210.67	3,747.60	10,383.28	4,242.38
Maneuvering	5.89	NA	NA	2,471.46	133.12	167.75	352.22	194.37
Idling	33.43	NA	NA	14,025.56	755.43	951.97	1,998.88	1,103.06
Dumurrage (aux gen)	33.52	NA	335,244	10,337.91	827.03	687.47	2,237.42	738.42
Barge								
Transit	31.09	NA	NA	12,176.60	522.26	885.35	2,434.09	1,025.86
Supply Boat Cranes	22.01	NA	359,363	11,081.67	886.53	736.93	2,398.39	791.55
Barge Cranes	8.80	NA	143,745	4,432.67	354.61	294.77	959.36	316.62
Trucks	11.01	NA	NA	1,109.72	245.42	0.00	841.02	0.00
Wheel Tractor	0.60	NA	NA	456.84	67.68	32.40	1,292.40	48.96
Dozer/Loader	15.84	NA	NA	595.44	70.56	54.72	144.72	41.76
NATURAL GAS								
Grinding\Process Equipment	NA	48,519	5,107,239	19,124.02	618.72	22.50	562.47	0.00
Injection Equipment	NA	2,059	216,777	811.72	26.26	0.95	23.87	0.00
TOTAL FUEL USAGE	293.78	50,578						
TOTAL EMISSIONS - TONS				64.08	3.36	3.79	11.77	4.30

87.31 Tons of Combined Air Emissions

AIRCITX6.WK3
08-Nov-94
COASTAL OIL AND GAS
DRILLING WASTE - COOK INLET ZERO DISCHARGE BASED ON 1,000,000 TOXICITY LIMITATION/LAND DISPOSAL OPTION
FUEL USAGE, HORSEPOWER REQUIREMENTS, AND AIR EMISSIONS
AIR EMISSION FACTORS GOTO A227
TOTAL FUEL USAGE & EMISSIONS GOTO A263

DRILLING WASTE VOLUME

Drilling Operation	Total Volume Drilling Waste (bbls)	Mude & Cuttings Per Well (bbls)	Number of Wells	Number of Wells Disposed at Alaska Landfill	Number of Wells Disposed at Idaho Landfill	Volume of Boxes (bbls)	Number of Boxes per Well
New Well	86,968 (a)	2,416	36 (a)	27	9	8	301.97
Recompletion	7,016 (a)	369	19 (a)	18	1	8	46.16
Total	93,984						

SUPPLY BOAT TRANSIT FUEL COMSUMPTION

Drilling Operation	Number of Boxes per Boat	Proportion of Well Waste Volume per Box	Number of Well Waste Volumes Per Boat	Total Wells	Number of Boat Trips	Miles Per Boat Trip	Total Boat Miles	Average Boat Speed (mi/hr)	Diesel Usage Rate (gal/hr)	Total Diesel Usage (gal)
New Well	227 (b)	0.0033	0.752	36	47.89	50 (c)	2,394	11.5 (d)	130 (e)	27,066
Recompletion	227 (b)	0.0217	4.916	19	3.86	50 (c)	193	11.5 (d)	130 (e)	2,184
Total										29,252

BARGE TRANSIT FUEL COMSUMPTION

Drilling Operation	Number of Boxes per Barge	Proportion of Well Waste Volume per Box	Number of Well Waste Volumes Per Barge	Total Wells	Number of Barge Trips	Miles Per Barge Trip	Total Barge Miles	Average Barge Speed (mi/hr)	Diesel Usage Rate (gal/hr)	Total Diesel Usage (gal)
New Well	340 (b)	0.0033	1.13	27	23.98	50 (f)	1,199	6 (g)	24 (h)	4,796
Recompletion	340 (b)	0.0217	7.37	18	2.44	50 (f)	122	6 (g)	24 (h)	489
Total										5,285

SUPPLY BOAT MANEUVERING FUEL CONSUMPTION

Drilling Operation	Total Number of Boat Trips	Manuvering Time Per Trip (hrs)	Diesel Usage Rate (gal/hr)	Total Fuel Consumption (gal)
New Well	47.69	1 (i)	25.3 (i)	1,212
Recompletion	3.66	1 (i)	25.3 (i)	98
Total				1,309

SUPPLY BOAT LOADING FUEL CONSUMPTION

Drilling Operation	Total Number of Boat Trips	Loading Time Per Trip (hrs)	Diesel Usage Rate (gal/hr)	Total Fuel Consumption (gal)
New Well	47.69	5.7 (i)	25.3 (i)	6,876
Recompletion	3.66	5.7 (i)	25.3 (i)	555
Total				7,431

SUPPLY BOAT AUXILIARY ELECTRICAL GENERATOR

Drilling Operation	Total Number of Boat Trips	Generator Hours Per Trip	Diesel Usage Rate (gal/hr)	Total Fuel Consumption (gal)	Generator Power Rating (hp)	Total Generator Horsepower-Hours
New Well	47.69	24 (i)	6 (i)	6,896	60 (i)	68,961
Recompletion	3.66	24 (i)	6 (i)	556	60 (i)	5,563
Total				7,452		74,525

SUPPLY BOAT CRANES

Drilling Operation	Number of Crane Lifts (drillsite)	Number of Crane Lifts (in port)	Total Crane Lifts Per Round Trip	Number of Crane lifts Per Hour	Crane lift Hours Per Round Trip	Total Number of Boat Trips	Total Crane Hours	Diesel Usage Rate (gal/hr)	Total Fuel Consumption (gal)	Crane Brake Horsepower (bhp)
New Well	56.8 (m)	56.8 (m)	113.5	10 (n)	11.35	47.89	544	8.33 (o)	4,528	136 (p)
Recompletion	56.8 (m)	56.8 (m)	113.5	10 (n)	11.35	3.86	44	8.33 (o)	365	136 (p)
Total									4,893	

BARGE CRANES

Drilling Operation	Number of Crane Lifts (loading)	Number of Crane Lifts (unloading)	Total Crane Lifts Per Round Trip	Number of Crane lifts Per Hour	Crane lift Hours Per Round Trip	Total Number of Boat Trips	Total Crane Hours	Diesel Usage Rate (gal/hr)	Total Fuel Consumption (gal)	Crane Brake Horsepower (bhp)
New Well	34 (p)	34	68	10 (n)	6.8	23.98	163.1	8.33 (o)	1,358	136 (n)
Recompletion	34 (p)	34	68	10 (n)	6.8	2.44	16.6	8.33 (o)	138	136 (n)
Total									1,497	

TRUCKS

Drilling Operation	Landfill Location	Boxes Per Truck (bbls)	Proportion of Well Waste Volume per Box	Number of Well Waste Volumes per Truck	Total Wells	Total Number of Truck Trips	Miles per Truck Trip	Total Truck Miles	Diesel Usage Rate (miles/gal)	Total Fuel Consumption (gal)
New Well	Alaska	12 (b)	0.0033	0.0397	27	679	10 (r)	6,794	4 (s)	1,699
Recompletion	Alaska	12 (b)	0.0217	0.2600	18	69	10 (r)	692	4 (s)	173
New Well	Idaho	8 (q)	0.0033	0.0265	9	340	5,000 (q)	1,698,594	4 (s)	424,648
Recompletion	Idaho	8 (q)	0.0217	0.1733	1	6	5,000 (q)	28,849	4 (s)	7,212
Total						749		1,734,929		433,732

WHEEL TRACTOR AT LANDFILL

Drilling Operation	Landfill Location	Total Wells	Tractor Time Per Well (hrs)	Total Tractor Time (hrs)	Diesel Usage Rate (gal/hr)	Total Fuel Consumption (gal)
New Well	Alaska	27	8 (1)	216	1.67 (1)	361
Recompletion	Alaska	18	8 (1)	144	1.67 (1)	240
New Well	Idaho	9	8 (1)	72	1.67 (1)	120
Recompletion	Idaho	1	8 (1)	8	1.67 (1)	13
Total				440		735

TRACK-TYPE DOZER/LOADER AT LANDFARM

Drilling Operation	Landfill Location	Total Wells	Dozer Time Per Well (hrs)	Total Dozer Time (hrs)	Diesel Usage Rate (gal/hr)	Total Fuel Consumption (gal)
New Well	Alaska	27	16 (1)	432	22 (1)	9,504
Recompletion	Alaska	18	16 (1)	288	22 (1)	6,336
New Well	Idaho	9	16 (1)	144	22 (1)	3,168
Recompletion	Idaho	1	16 (1)	16	22 (1)	352
Total				880		19,360

AIR EMISSION FACTORS

06-Nov-94

Category	Units	NOx	THC	SO2	CO	TSP
DIESEL						
Supply Boats						
Transit	(lb/1000 gal)	391.700	16.800	28.460	78.300	33.000
Maneuvering	(lb/1000 gal)	419.600	22.600	28.460	59.600	33.000
Idling	(lb/1000 gal)	419.600	22.600	28.460	59.600	33.000
Demurrage (aux gen)	(g/bhp-hr)	14.000	1.120	0.931	3.030	1.000
Barge						
Transit	(lb/1000 gal)	391.700	16.800	28.460	78.300	33.000
Cranes						
Drill Site	(g/bhp-hr)	14.000	1.120	0.931	3.030	1.000
In-Port	(g/bhp-hr)	14.000	1.120	0.931	3.030	1.000
Trucks	(g/mile)	11.440	2.530	NA	8.670	NA
Wheel Tractor	(lb/hr)	1.269	0.168	0.090	3.590	0.136
Dozer/Loader	(lb/hr)	0.827	0.098	0.076	0.201	0.058
NATURAL GAS						
Gas-fired Turbine	(g/hp-hr)	1.700	0.055	0.002	0.050	NA

REFERENCE:
Non-Water Quality Environmental Impacts Resulting From the Onshore Disposal of
Drilling Fluids and Drill Cuttings from Offshore Oil and Gas Drilling Activities," US EPA, January 13, 1993, p. D-22.

TOTAL AIR EMISSIONS – ZERO DISCHARGE BASED ON COMBINED OPTION 06-Nov-94

Category	Total Diesel Fuel Usage (1000 gal)	Natural Gas Usage (1000scf)	Power Requirements (hp-hr)	Nox Total (lbs)	THC Total (lbs)	SO2 Total (lbs)	CO Total (lbs)	TSP Total (lbs)
DIESEL								
Supply Boats								
Transit	29.25	NA	NA	11,457.96	491.43	833.09	2,290.42	965.31
Maneuvering	1.31	NA	NA	549.41	29.59	37.29	78.30	43.21
Idling	7.43	NA	NA	3,117.88	167.93	211.62	444.35	245.21
Demurrage (aux gen)	7.45	NA	74,525	2,298.12	183.85	152.62	497.38	164.15
Barge								
Transit	5.28	NA	NA	2,070.04	88.78	150.51	413.80	174.40
Supply Boat Cranes	4.69	NA	79,888	2,463.48	197.08	163.82	533.18	175.96
Barge Cranes	1.50	NA	24,437	753.56	60.28	50.11	163.09	53.83
Trucks	433.73	NA	NA	43,717.16	9,668.22	0.00	33,131.80	0.00
Wheel Tractor	0.73	NA	NA	558.36	82.72	39.60	1,579.60	59.84
Dozer/Loader	19.36	NA	NA	727.76	88.24	66.88	176.88	51.04
NATURAL GAS								
Grinding\Process Equipment	NA	0	0	0.00	0.00	0.00	0.00	0.00
Injection Equipment	NA	0	0	0.00	0.00	0.00	0.00	0.00
TOTAL FUEL USAGE	510.95	0						
TOTAL EMISSIONS – TONS				33.88	5.53	0.85	19.65	0.97
OVERALL TOTAL	60.88 Tons of Combined Air Emissions							

APPENDIX XVI-2

NWQI Spreadsheets for Existing Sources of Produced Water Discharges in Gulf of Mexico

	Zero Discharge	Gas Flotation
Fuel Consumption for Barging:	224,786 gal/yr	204,752 gal/yr
Fuel Consumption Vacuum Pump:	64.26 gal/yr	64.26 gal/yr
Fuel Consumption Compressor:	374.85 gal/yr	374.85 gal/yr

Printed: 14-Nov-94

AIR EMISSIONS AND FUEL CONSUMPTION SUMMARY FOR ZERO DISCHARGE IN LOUISIANA – BAT

Facility Size	Total Flow (bpd)	Diesel Fuel Reqmt's (Mgal/yr)	Nat. Gas Fuel Reqmt's (MMscf/yr)	Emissions (tons/yr)					
				CO	NOx	SO2	THC	TSP	Total
Small-Volume	426	225.23	0	8.82	44.13	3.21	1.90	3.72	61.77
Med/Large-Volume	415,493	0	1,227.262	199.18	1,565.01	0.24	626.00	0.00	2,390.43
TOTAL	415,919	225.23	1,227.262	208.00	1,609.14	3.45	627.90	3.72	2,452.20

AIR EMISSIONS AND FUEL CONSUMPTION SUMMARY FOR GAS FLOTATION IN LOUISIANA – BAT

Facility Size	Total Flow (bpd)	Diesel Fuel Reqmt's (Mgal/yr)	Nat. Gas Fuel Reqmt's (MMscf/yr)	Emissions (tons/yr)					
				CO	NOx	SO2	THC	TSP	Total
Small-Volume	179	205.19	0	8.04	40.20	2.92	1.73	3.39	56.28
Med/Large-Volume	415,740	0	87.538	14.21	111.62	0.01	44.66	0	170.50
TOTAL	415,919	205.19	87.538	22.25	151.82	2.93	46.39	3.39	226.78

LOUISIANA MEDIUM/LARGE-VOLUME FACILITIES -- Zero Discharge -- BAT (PRODUCED WATER)

Permit-Outfall Number	Operator	Current Avg. Vol (bpd)	Electric Power (hp)	Electric Power (hp-hr/yr)	Diesel Fuel Reqmt's (gal/yr)	Nat. Gas Power (hp)	Nat. Gas Power (hp-hr/yr)	Nat. Gas Fuel Reqmt's (MMscf/yr)	Emissions (tons/yr) CO	NO2	SO2	THC	TSP	Total
3040-001	Alliance Operating Corp.	1,678.0	2.1	18,502	0	51.2	448,550	4.261	0.69	5.43	0.00	2.17	0.00	8.29
3650-001	Alltex Exploration, Inc.	465.0	17.6	154,221	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0
3408-001	Amerada Hess Corp.	3,662.0	4.7	41,096	0	125.0	1,095,080	10.403	1.69	13.27	0.00	5.31	0.00	20.27
2184-001	Ashlawn Energy, Inc.	3,142.7	4.0	35,182	0	105.7	925,854	8.796	1.43	11.22	0.00	4.49	0.00	17.14
2184-002	Ashlawn Energy, Inc.	3,142.7	4.0	35,182	0	105.7	925,854	8.796	1.43	11.22	0.00	4.49	0.00	17.14
2184-003	Ashlawn Energy, Inc.	3,142.7	4.0	35,182	0	105.7	925,854	8.796	1.43	11.22	0.00	4.49	0.00	17.14
3795-001	Atlas Production Services, Inc.	151.5	7.5	66,066	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0
3795-002	Atlas Production Services, Inc.	151.5	7.5	66,066	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0
3686-001	Bois d'Arc Operating Corp.	925.0	1.1	9,927	0	23.2	203,168	1.930	0.31	2.46	0.00	0.98	0.00	3.75
3870-001	Bois d'Arc Operating Corp.	1,010.0	1.2	10,895	0	26.4	230,867	2.193	0.36	2.80	0.00	1.12	0.00	4.28
3086-001	Burk Royalty Co.	450	17.1	150,003	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0
1901-001	Callon Offshore Production, Inc.	30,200.0	24.0	210,240	0	1112.2	9,743,071	92.559	15.02	118.03	0.02	47.21	0.00	180.28
1901-002	Callon Offshore Production, Inc.	30,200.0	24.0	210,240	0	1112.2	9,743,071	92.559	15.02	118.03	0.02	47.21	0.00	180.28
1934-001-1	Callon Offshore Production, Inc.	14,443.0	18.7	163,870	0	526.1	4,608,306	43.779	7.11	55.83	0.01	22.33	0.00	85.28
2142-001-1	Callon Offshore Production, Inc.	12,076.0	15.6	136,914	0	438.0	3,836,967	36.451	5.92	46.48	0.01	18.59	0.00	71
2672-001-2	Callon Offshore Production, Inc.	9,175.0	11.9	103,878	0	330.1	2,891,612	27.470	4.46	35.03	0.01	14.01	0.00	53.51
2859-001	Callon Offshore Production, Inc.	11,290.0	14.6	127,963	0	408.8	3,580,831	34.018	5.52	43.38	0.01	17.35	0.00	66.26
2860-003	Callon Offshore Production, Inc.	7,120.0	9.2	80,475	0	253.6	2,221,945	21.108	3.43	26.92	0.00	10.77	0.00	41.12
1857-001 to 011	Chevron U.S.A., Inc.	18,659.7	24.0	210,240	0	682.9	5,982,410	56.833	9.22	72.47	0.01	28.99	0.00	110.69
1861-001	Chevron U.S.A., Inc.	4,600.0	5.9	51,778	0	159.9	1,400,748	13.307	2.16	16.97	0.00	6.79	0.00	25.92
1863-001	Chevron U.S.A., Inc.	27,856.0	24.0	210,240	0	1025.0	8,979,227	85.303	13.84	108.78	0.02	43.51	0.00	166.15
1896	Chevron U.S.A., Inc.	35,652.0	46.3	405,398	0	1315.0	11,519,725	109.437	17.76	139.56	0.03	55.82	0.00	213.17
3230	Chevron Pipe Line Co.	0	0.0	0	0	0.0	0	0.000	0.00	0.00	0.00	0.00	0.00	0
3853-001	Cliffs Oil & Gas Co.	245.0	10.5	92,358	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0
3267	Conoco, Inc.	0.0	0.0	0	0	0.0	0	0.000	0.00	0.00	0.00	0.00	0.00	0
3038-001	CXY Energy, Inc.	500.0	18.7	164,063	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0
3067-000	Denovo Oil and Gas, Inc.	200.0	9.1	79,704	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0
2185-001	Energy Development Corp.	700.0	0.8	7,365	0	14.8	129,847	1.234	0.20	1.57	0.00	0.63	0.00	2.4
2785-001	Energy Development Corp.	250.0	10.7	93,764	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0
2779-001	Graham Royalty, Ltd.	950.0	1.2	10,212	0	24.1	211,315	2.007	0.33	2.56	0.00	1.02	0.00	3.91
4029-001	Hilcorp Energy Co.	3,522.0	4.5	39,501	0	119.8	1,049,458	9.970	1.62	12.71	0.00	5.09	0.00	19.42
4467-001	Houma Production Co.	400.0	15.5	135,943	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0
2368-001 to 006	Hunt Petroleum Co.	5,625.0	7.2	63,450	0	198.0	1,734,766	16.480	2.67	21.02	0.00	8.41	0.00	32.1
3008-001	Hunt Petroleum Co.	266.0	11.2	98,263	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0
3029-001	James A. Whitson, Jr.	300.0	12.3	107,823	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0
2875-000	Jordan Oil Co.	0.0	0.0	0	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0
3081-001	Konantz, Inc.	613.0	22.4	195,838	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0
2710-001	Linder Oil Co.	904.0	1.1	9,688	0	22.4	196,325	1.865	0.30	2.38	0.00	0.95	0.00	3.63
1853-001	LLECO Holdings, Inc.	324.0	13.1	114,572	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0
3746-001	Marblehead Energy Corp.	1,250.0	1.6	13,628	0	35.3	309,076	2.936	0.48	3.74	0.00	1.50	0.00	5.72
2164-001-1	Oryx Energy Co.	150.0	7.5	65,644	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0
3223-001	Pel-Tex Oil Co.	186.0	8.6	75,767	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0
3407-001	Pennzoil Exploration & Production Co.	6,300.0	8.1	71,137	0	223.1	1,954,730	18.570	3.01	23.68	0.00	9.47	0.00	36.16
2838-001	Petro Corp.	1,500.0	1.9	16,475	0	44.6	390,544	3.710	0.60	4.73	0.00	1.89	0.00	7.22
2227-001	Quintana Petroleum Corp.	600.0	21.9	192,182	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0
2071	Shell	144,000.0	24.0	210,240	0	5345.6	46,827,304	444.859	72.20	567.29	0.10	226.92	0.00	866.51
2084-001	Texaco, Inc.	1,715.6	2.2	18,930	0	52.6	460,802	4.378	0.71	5.58	0.00	2.23	0.00	8.52
2084-003-1	Texaco, Inc.	1,715.6	2.2	18,930	0	52.6	460,802	4.378	0.71	5.58	0.00	2.23	0.00	8.52
2084-005	Texaco, Inc.	1,715.6	2.2	18,930	0	52.6	460,802	4.378	0.71	5.58	0.00	2.23	0.00	8.52
2084-012	Texaco, Inc.	1,715.6	2.2	18,930	0	52.6	460,802	4.378	0.71	5.58	0.00	2.23	0.00	8.52
2084-015	Texaco, Inc.	1,715.6	2.2	18,930	0	52.6	460,802	4.378	0.71	5.58	0.00	2.23	0.00	8.52
2084-016	Texaco, Inc.	1,715.6	2.2	18,930	0	52.6	460,802	4.378	0.71	5.58	0.00	2.23	0.00	8.52
2816-011	Texaco, Inc.	291.1	12.0	105,321	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0
2825-001 to 003	Texaco, Inc.	1,998.9	2.5	22,156	0	63.1	553,122	5.255	0.85	6.70	0.00	2.68	0.00	10.23
2882-001/002	Texaco, Inc.	1,494.0	1.9	16,407	0	44.4	388,589	3.692	0.60	4.71	0.00	1.88	0.00	7.19
2970-001	Texaco, Inc.	500.0	18.7	164,063	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0
2971-001	Texaco, Inc.	2,650.0	3.4	29,571	0	87.4	765,297	7.270	1.18	9.27	0.00	3.71	0.00	14.16
2971-002	Texaco, Inc.	2,650.0	3.4	29,571	0	87.4	765,297	7.270	1.18	9.27	0.00	3.71	0.00	14.16
3032-001	Texoil Co.	939.0	1.2	10,086	0	23.7	207,730	1.973	0.32	2.52	0.00	1.01	0.00	3.85
2547-001	Torch Operating Co.	109.0	6.2	54,115	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0
2708-001	Torch Operating Co.	278.0	11.6	101,637	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0
1950-001	Warren Petroleum Co.	1,680.0	2.1	18,525	0	51.3	449,201	4.267	0.69	5.44	0.00	2.18	0.00	8.31
3039-001	Wichita River Oil Corp.	270.0	11.3	99,387	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0
2909-001	WRT Energy Corp.	3,252.0	4.2	36,427	0	109.8	961,472	9.134	1.48	11.65	0.00	4.66	0.00	17.79
2118-001 to 003	W.W.F. Oil Corp	1,110.0	1.4	12,034	0	30.1	263,454	2.503	0.41	3.19	0.00	1.28	0.00	4.88
	TOTAL:	415,493	--	--	0	--	--	1,227.262	199.18	1,565.01	0.24	626.00	0.00	2,390.43

LOUISIANA MEDIUM/LARGE-VOLUME FACILITIES – Gas Flotation – BAT (PRODUCED WATER)

Permit-Outfall Number	Operator	Current Avg. Vol (bpd)	Electric Power (hp)	Electric Power (hp-hr/yr)	Diesel Fuel Reqmt's (gal/yr)	Nat. Gas Power (hp)	Nat. Gas Power (hp-hr/yr)	Nat. Gas Fuel Reqmt's (MMscf/yr)	Emissions (tons/yr) CO	NOx	SO2	THC	TSP	Total
3040-001	Alliance Operating Corp.	1,678.0	15.09	132,199	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
3650-001	Alltex Exploration, Inc.	465.0	12.35	108,184	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
3408-001	Amerada Hess Corp.	3,662.0	19.58	171,477	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2184-001 to 003	Ashlawn Energy, Inc.	9,428.1	0	0	0	34.24	299,920.67	2.849	0.46	3.63	0.00	1.45	0.00	5.54
3795-001	Atlas Production Services, Inc.	151.5	11.64	101,978	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
3795-002	Atlas Production Services, Inc.	151.5	11.64	101,978	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
3686-001	Bois d'Arc Operating Corp.	925.0	13.39	117,291	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
3870-001	Bois d'Arc Operating Corp.	1,010.0	13.58	118,974	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
3086-001	Burk Royalty Co.	450	12.32	107,887	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
1901-001	Callon Offshore Production, Inc.	30,200.0	0	0	0	88.14	772,111.66	7.335	1.19	9.35	0.00	3.74	0.00	14.28
1901-002	Callon Offshore Production, Inc.	30,200.0	0	0	0	88.14	772,111.66	7.335	1.19	9.35	0.00	3.74	0.00	14.28
1934-001-1	Callon Offshore Production, Inc.	14,443.0	0	0	0	47.25	413,920.38	3.932	0.64	5.01	0.00	2.01	0.00	7.66
2142-001-1	Callon Offshore Production, Inc.	12,076.0	0	0	0	41.11	360,113.26	3.421	0.56	4.36	0.00	1.75	0.00	6.67
2672-001-2	Callon Offshore Production, Inc.	9,175.0	0	0	0	33.58	294,167.15	2.795	0.45	3.56	0.00	1.43	0.00	5.44
2859-001	Callon Offshore Production, Inc.	11,290.0	0	0	0	39.07	342,245.75	3.251	0.53	4.15	0.00	1.66	0.00	6.34
2860-003	Callon Offshore Production, Inc.	7,120.0	0	0	0	28.25	247,452.48	2.351	0.38	3.00	0.00	1.20	0.00	4.58
3074-001	Cashco Oil Co.	72.0	11.46	100,404	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
1857-001 to 011	Chevron U.S.A., Inc.	18,659.7	0	0	0	58.19	509,775.25	4.843	0.79	6.18	0.00	2.47	0.00	9.44
1861-001	Chevron U.S.A., Inc.	4,600.0	21.69	190,047	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
1863-001	Chevron U.S.A., Inc.	27,856.0	0	0	0	82.06	718,827.38	6.829	1.11	8.71	0.00	3.48	0.00	13.30
1896	Chevron U.S.A., Inc.	35,652.0	0	0	0	102.29	896,047.61	8.512	1.38	10.86	0.00	4.34	0.00	16.58
3230	Chevron Pipe Line Co.	0	0	0	0	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
3853-001	Cliffs Oil & Gas Co.	245.0	11.85	103,829	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
3267	Conoco, Inc.	0.0	0	0	0	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
3038-001	CXY Energy, Inc.	500.0	12.43	108,877	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
3067-000	Denovo Oil and Gas, Inc.	200.0	11.75	102,938	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2185-001	Energy Development Corp.	700.0	12.88	112,837	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2785-001	Energy Development Corp.	250.0	11.86	103,928	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2779-001	Graham Royalty, Ltd.	950.0	13.45	117,786	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
4029-001	Hilcorp Energy Co.	3,522.0	19.26	168,706	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
4467-001	Houma Production Co.	400.0	12.20	106,897	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2704-001	Hunt Petroleum Co.	75.0	11.47	100,463	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2368-001	Hunt Petroleum Co.	1,125.0	13.84	121,251	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2368-002	Hunt Petroleum Co.	1,125.0	13.84	121,251	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2368-003	Hunt Petroleum Co.	1,125.0	13.84	121,251	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2368-005	Hunt Petroleum Co.	1,125.0	13.84	121,251	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2368-006	Hunt Petroleum Co.	1,125.0	13.84	121,251	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
3008-001	Hunt Petroleum Co.	266.0	11.90	104,245	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
3029-001	James A. Whitson, Jr.	300.0	11.98	104,918	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2875-000	Jordan Oil Co.	0.0	0.00	0	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
3081-001	Konantz, Inc.	613.0	12.68	111,114	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2710-001	Linder Oil Co.	904.0	13.34	116,875	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
1853-001	LLECO Holdings, Inc.	324.0	12.03	105,393	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
3746-001	Marblehead Energy Corp.	1,250.0	14.12	123,725	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2164-001-1	Oryx Energy Co.	150.0	11.64	101,948	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
3223-001	Pel-Tex Oil Co.	186.0	11.72	102,661	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
3407-001	Pennzoil Exploration & Production Co.	6,300.0	0	0	0	26.12	228,812.08	2.174	0.35	2.77	0.00	1.11	0.00	4.23
2838-001	Petro Corp.	1,500.0	14.69	128,675	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2227-001	Quintana Petroleum Corp.	600	12.65	110,857	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2626-001	Samedan Oil Corp.	100.0	11.52	100,958	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2071	Shell	144,000.0	0	0	0	383.45	3,359,036.02	31.911	5.18	40.69	0.01	16.28	0.00	62.16
2084-001	Texaco, Inc.	1,715.6	15.18	132,943	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2084-003-1	Texaco, Inc.	1,715.6	15.18	132,943	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2084-005	Texaco, Inc.	1,715.6	15.18	132,943	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2084-012	Texaco, Inc.	1,715.6	15.18	132,943	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2084-015	Texaco, Inc.	1,715.6	15.18	132,943	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2084-016	Texaco, Inc.	1,715.6	15.18	132,943	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2816-011	Texaco, Inc.	291.1	11.96	104,741	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2825-001	Texaco, Inc.	666.3	12.80	112,170	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2825-002	Texaco, Inc.	666.3	12.80	112,170	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2825-003	Texaco, Inc.	666.3	12.80	112,170	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2882-001/002	Texaco, Inc.	1,494.0	14.68	128,556	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2970-001	Texaco, Inc.	500.0	12.43	108,877	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2971-001	Texaco, Inc.	2,650.0	17.29	151,442	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2971-002	Texaco, Inc.	2,650.0	17.29	151,442	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
3032-001	Texoil Co.	939.0	13.42	117,568	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2547-001	Torch Operating Co.	109.0	11.55	101,136	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2708-001	Torch Operating Co.	278.0	11.93	104,482	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
1950-001	Warren Petroleum Co.	1,680.0	15.10	132,238	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
3039-001	Wichita River Oil Corp.	270.0	11.91	104,324	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2909-001	WRT Energy Corp.	3,252.0	18.65	163,360	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
2118-001 to 003	W.W.F. Oil Corp.	1,110.0	13.81	120,954	0	0	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL	415,740	--	--	0	--	--	87.538	14.21	111.62	0.01	44.66	0.00	170.50

Printed: 14-Nov-94

AIR EMISSIONS AND FUEL CONSUMPTION SUMMARY FOR ZERO DISCHARGE IN TEXAS – BAT

Facility Size	Total Flow (bpd)	Diesel Fuel Reqmt's (Mgal/yr)	Nat. Gas Fuel Reqmt's (MMscf/yr)	Emissions (tons/yr)					
				CO	NOx	SO2	THC	TSP	Total
Small–Volume	1,033	190.20	0.000	7.26	5.00	0.00	0.00	0.00	12.26
Med/Large–Volume	72,285	0	171.922	27.91	219.23	0.01	87.71	0	334.86
TOTAL	73,318	190.20	171.922	35.17	224.23	0.01	87.71	0.00	347.12

AIR EMISSIONS AND FUEL CONSUMPTION SUMMARY FOR GAS FLOTATION IN TEXAS – BAT

Facility Size	Total Flow (bpd)	Diesel Fuel Reqmt's (Mgal/yr)	Nat. Gas Fuel Reqmt's (MMscf/yr)	Emissions (tons/yr)					
				CO	NOx	SO2	THC	TSP	Total
Small–Volume	1,254	230.88	0.000	8.82	8.00	0.00	0.00	0.00	16.82
Med/Large–Volume	72,064	0	6.742	1.09	8.59	0	3.44	0	13.12
TOTAL	73,318	230.88	6.742	9.91	16.59	0.00	3.44	0.00	29.94

Assumptions for Small–Volume:

Truck Capacity: 119 bbl (EPA, Jan. 13, 1993)
Truck Fuel Usage: 4 mi/gal – diesel (EPA, Jan. 13, 1993)
Miles traveled are estimated as roundtrips
Truck Roundtrip Distance: 120 mi (SAIC, Jan. 5, 1995)

TEXAS SMALL–VOLUME FACILITIES – Zero Discharge – BAT

Permit No.	Texas Operator	Current Volume (BPD)	Storage Capacity (Days)	Number Truck–Trips per Year	Miles Traveled per Year	Diesel Fuel Usage – Trucks (Mgal/yr)	Emissions (tons/yr)					
							CO	NOx	SO2	THC	TSP	Total
663	AMOCO PRODUCTION CO	15	10.0	46	11,040	2.76	0.11	0.00	0.00	0.00	0.00	0.11
655	BAY OPERATING CO, INC.	15	10.0	46	11,040	2.76	0.11	0.00	0.00	0.00	0.00	0.11
590	BKN OIL & GAS, INC	43	3.5	132	31,680	7.92	0.30	0.00	0.00	0.00	0.00	0.30
590	BKN OIL & GAS, INC	50	3.0	153	36,720	9.18	0.35	0.00	0.00	0.00	0.00	0.35
590	BKN OIL & GAS, INC	40	3.8	123	29,520	7.38	0.28	0.00	0.00	0.00	0.00	0.28
590	BKN OIL & GAS, INC	35	4.3	107	25,680	6.42	0.25	0.00	0.00	0.00	0.00	0.25
590	BKN OIL & GAS, INC	13	11.5	40	9,600	2.40	0.09	0.00	0.00	0.00	0.00	0.09
590	BKN OIL & GAS, INC	32	4.7	98	23,520	5.88	0.22	0.00	0.00	0.00	0.00	0.22
590	BKN OIL & GAS, INC	68	2.2	209	50,160	12.54	0.48	1.00	0.00	0.00	0.00	1.48
195	BRISTOL RESOURCES CORP	16	9.4	49	11,760	2.94	0.11	0.00	0.00	0.00	0.00	0.11
197	BRISTOL RESOURCES CORP	32	4.7	98	23,520	5.88	0.22	0.00	0.00	0.00	0.00	0.22
8	BROWN CLIFFORD L, JR	25	6.0	77	18,480	4.62	0.18	0.00	0.00	0.00	0.00	0.18
214	BROWN, GEORGE R PRTRSHP	22	6.8	67	16,080	4.02	0.15	0.00	0.00	0.00	0.00	0.15
747	CAVALLA ENERGY EXPLORATION CO	43	3.5	132	31,680	7.92	0.30	0.00	0.00	0.00	0.00	0.30
64	COASTAL OIL & GAS CORP	40	3.8	123	29,520	7.38	0.28	0.00	0.00	0.00	0.00	0.28
628	CONVEST ENERGY CORP	15	10.0	46	11,040	2.76	0.11	0.00	0.00	0.00	0.00	0.11
792	CORPUS CHRISTI LEASEHOLDS, INC	4	37.5	12	2,880	0.72	0.03	0.00	0.00	0.00	0.00	0.03
723	CORPUS CHRISTI OIL & GAS CO	15	10.0	46	11,040	2.76	0.11	0.00	0.00	0.00	0.00	0.11
708	CORPUS CHRISTI OIL & GAS CO	8	18.8	25	6,000	1.50	0.06	0.00	0.00	0.00	0.00	0.06
104	EBB TIDE OIL CO	55	2.7	169	40,560	10.14	0.39	1.00	0.00	0.00	0.00	1.39
71	EBB TIDE OIL CO	4	37.5	12	2,880	0.72	0.03	0.00	0.00	0.00	0.00	0.03
752	HOUSTON OIL PROD ENT, INC	10	15.0	31	7,440	1.86	0.07	0.00	0.00	0.00	0.00	0.07
753	HOUSTON OIL PROD ENT, INC	29	5.2	89	21,360	5.34	0.20	0.00	0.00	0.00	0.00	0.20
102	KARBUHN OIL CO	46	3.3	141	33,840	8.46	0.32	0.00	0.00	0.00	0.00	0.32
184	LA PARRITA OIL & GAS, INC	12	12.5	37	8,880	2.22	0.08	0.00	0.00	0.00	0.00	0.08
582	LAMAR OIL & GAS, INC	70	2.1	215	51,600	12.90	0.49	1.00	0.00	0.00	0.00	1.49
111	MARSHALL PETROLEUM, INC	10	15.0	31	7,440	1.86	0.07	0.00	0.00	0.00	0.00	0.07
238	MERRICO RESOURCES, INC	34	4.4	104	24,960	6.24	0.24	0.00	0.00	0.00	0.00	0.24
206	MIDCON OFFSHORE, INC	10	15.0	31	7,440	1.86	0.07	0.00	0.00	0.00	0.00	0.07
119	M.K. MCDANIEL	44	3.4	135	32,400	8.10	0.31	0.00	0.00	0.00	0.00	0.31
645	OIL LEASE OPERATING CO	10	15.0	31	7,440	1.86	0.07	0.00	0.00	0.00	0.00	0.07
14	PI ENERGY, INC	20	7.5	61	14,640	3.66	0.14	0.00	0.00	0.00	0.00	0.14
638	PINELL, H P TRUSTEE	24	6.3	74	17,760	4.44	0.17	0.00	0.00	0.00	0.00	0.17
176	S.S.C. GAS PRODUCING CO	60	2.5	184	44,160	11.04	0.42	1.00	0.00	0.00	0.00	1.42
201	TIERRA MINERAL DEVELOPMENT	1	150.0	3	720	0.18	0.01	0.00	0.00	0.00	0.00	0.01
547	WAINOCO OIL & GAS CO	2	75.0	6	1,440	0.36	0.01	0.00	0.00	0.00	0.00	0.01
170	WESTLAND OIL DEVELOPMENT CORP	1	150.0	3	720	0.18	0.01	0.00	0.00	0.00	0.00	0.01
552	WILSON HYDROCARBON, INC	60	2.5	184	44,160	11.04	0.42	1.00	0.00	0.00	0.00	1.42
	TOTAL:	1,033	–	–	–	190.20	7.26	5.00	0.00	0.00	0.00	12.26

TEXAS MEDIUM/LARGE-VOLUME FACILITIES -- Zero Discharge -- BAT (PRODUCED WATER)

Permit No.	Texas Operator	Current Volume (BPD)	Electric Power (hp)	Electric Power (hp-hr/yr)	Diesel Fuel Reqmt's (gal/yr)	Nat. Gas Power (hp)	Nat. Gas Power (hp-hr/yr)	Nat. Gas Fuel Reqmt's (MMscf/yr)	Emissions (tons/yr) CO	NOx	SO2	THC	TSP	Total
163	ACE PRODUCTIONS	450	16.1	141,243	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
136	AMERICAN EXPLORATION CO	4,476	0	0	0	157.5	1,379,701	13.107	2.13	16.71	0.00	6.69	0.00	25.53
666	AMERICAN EXPLORATION CO	335	12.4	108,905	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
19	APACHE CORP	1,685	0	0	0	57.4	502,465	4.773	0.77	6.09	0.00	2.43	0.00	9.29
590	BKN OIL & GAS, INC	2,436	0	0	0	84.3	738,511	7.016	1.14	8.95	0.00	3.58	0.00	13.67
684	BRANDES PETROLEUM INC	250	9.7	85,004	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
105	BROWN, CLIFFORD L, JR	2,370	0	0	0	81.9	717,766	6.819	1.11	8.70	0.00	3.48	0.00	13.29
90,113	BROWN, GEORGE R. PRTNRSHP	6,670	0	0	0	236.2	2,069,294	19.658	3.19	25.07	0.00	10.03	0.00	38.29
693	BRYMER CONTRACTING CO	436	15.7	137,306	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
673	BWS VACUUM SERVICE, INC.	130	5.9	51,260	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
60	CEDAR POINT OIL CO	1,200	0	0	0	40.0	350,025	3.325	0.54	4.24	0.00	1.70	0.00	6.48
675	CHAIN OIL & GAS, INC	210	8.4	73,756	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
857	CLARON CORP	175	7.3	63,914	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
904	COASTAL OIL & GAS CORP	4,839	0	0	0	170.5	1,493,795	14.191	2.30	18.10	0.00	7.24	0.00	27.64
905	COASTAL OIL & GAS CORP	74	4.1	35,513	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
616	CREST RESOURCES & EXPLOR	400	14.5	127,183	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
694	CREST RESOURCES & EXPLOR	180	7.5	65,320	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
710	DANJ HARRISON III&FH BRUCE	150	6.5	56,884	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
637	DENOVO OIL & GAS, INC	652	22.6	198,044	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
241	DEWBRE PETROLEUM CORP	155	6.7	58,290	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
649	DYNAMIC PRODUCTION, INC.	80	4.2	37,200	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
13	ENSENJAY PETROLEUM CORP	1,193	0	0	0	39.7	347,825	3.304	0.54	4.21	0.00	1.69	0.00	6.44
80	EXXON CORP	1,948	0	0	0	66.8	585,128	5.559	0.90	7.09	0.00	2.84	0.00	10.83
81	EXXON CO, USA	888	0	0	0	28.8	251,961	2.394	0.39	3.05	0.00	1.22	0.00	4.66
26	EXXON CORP - HOUSTON	7,495	0	0	0	265.8	2,328,599	22.122	3.59	28.21	0.01	11.28	0.00	43.09
202	FORT WORTH OIL AND GAS	84	4.4	38,325	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
89	GOODRICH OPERATING CO, INC	137	6.1	53,228	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
739	GRAHAM ROYALTY, LTD	330	12.3	107,499	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
635	GULF VACUUM SERVICE	1,290	0	0	0	43.2	378,313	3.594	0.58	4.58	0.00	1.83	0.00	6.99
627	HAPS OIL & GAS CORP	185	7.6	66,726	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
134	HEADINGTON OIL CO	400	14.5	127,183	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
885	HOUSTON OIL & MINERALS CORP	168	7.1	61,945	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
632	KANSAS OIL & GAS CO	904	0	0	0	29.3	256,990	2.441	0.40	3.11	0.00	1.25	0.00	4.76
152	KEPLINGER OPERATING CO	80	4.2	37,200	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
249	KILLAM OIL CO	3,755	0	0	0	131.6	1,153,084	10.954	1.78	13.97	0.00	5.59	0.00	21.34
122	KILMARNOCK OIL CO	200	8.1	70,944	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
672	KING OIL	120	5.5	48,448	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
587	LINDA PRODUCTION, INC	80	4.2	37,200	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
264	LIVE OAK RESERVES, INC	775	0	0	0	24.7	216,444	2.056	0.33	2.62	0.00	1.05	0.00	4.00
659	LONE OAK DISPOSAL CO	248	9.6	84,441	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
580	LUNDY VACUUM SERVICE, INC	100	4.9	42,824	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
207	MIRESCO, INC	1,033	0	0	0	34.0	297,536	2.827	0.46	3.60	0.00	1.44	0.00	5.50
1	NEUMIN PRODUCTION CO	88	4.5	39,450	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
68	ORANGE PETROLEUM CO	5,759	0	0	0	203.5	1,782,959	16.938	2.75	21.60	0.00	8.64	0.00	32.99
577	PATON OIL CORP	682	23.6	206,480	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
789	PAX PETROLEUM CORP	350	12.9	113,123	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
276	PEARL, BILL H. PROD, INC	375	13.7	120,153	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
166	PETRO VEST, INC	100	4.9	42,824	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
167	PETRO VEST, INC	400	14.5	127,183	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
242	PI ENERGY, INC	600	20.9	183,422	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
4CCC	PI ENERGY, INC	75	4.1	35,794	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
595	POYNOR CORP	72	4.0	34,951	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
822	POYNOR CORP	1,000	0	0	0	32.8	287,163	2.728	0.44	3.48	0.00	1.39	0.00	5.31
282	REDFISH BAY OPERATING CORP	110	5.2	45,636	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
613	REDFISH BAY OPERATING CORP	600	20.9	183,422	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
744	SCANA EXPLORATION CO	1,200	0	0	0	40.0	350,025	3.325	0.54	4.24	0.00	1.70	0.00	6.48
127,132	SHELTON, CHARLES, H	574	20.1	176,111	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
685	SNR OILFIELD SERVICES, INC	600	20.9	183,422	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
124	S&S ENERGY, INC	783	0	0	0	25.0	218,958	2.080	0.34	2.65	0.00	1.06	0.00	4.05
674	TD OPERATING CO	200	8.1	70,944	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
20	TEXACO E & P INC	275	10.5	92,033	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
85	TEXACO E & P INC	112	5.3	46,198	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
155	TEXACO E & P, INC	1,660	0	0	0	56.5	494,607	4.699	0.76	5.99	0.00	2.40	0.00	9.15
156	TEXACO E & P, INC	2,746	0	0	0	95.4	835,946	7.941	1.29	10.13	0.00	4.05	0.00	15.47
157	TEXACO E & P, INC	479	17.1	149,397	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
854	TEXANA OPERATING CO	185	7.6	66,726	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
177	TEXAS PETROLEUM CO	1,500	0	0	0	50.7	444,318	4.221	0.69	5.38	0.00	2.15	0.00	8.22
189	TIERRA MINERAL DEVELOPMENT	2,045	0	0	0	70.3	615,616	5.848	0.95	7.46	0.00	2.98	0.00	11.39
165	UNION OIL CO OF CA	144	6.3	55,197	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
47	UNITED TEXAS CORP (A)	150	6.5	56,884	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
605	WHITTINGTON OPERATING CO	245	9.5	83,598	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
680	ZILKA ENERGY CO	110	5.2	45,636	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
219	ZINN PETROLEUM CO	300	11.3	99,063	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL:	72,285	--	--	--	--	--	171.922	27.91	219.23	0.01	87.71	0.00	334.86

TEXAS SMALL–VOLUME FACILITIES – GAS FLOTATION

Permit No.	Operator	Current Volume (BPD)	Storage Capacity (Days)	Number Truck–Trips per Year	Miles Traveled per Year	Diesel Fuel Usage – Trucks (Mgal/yr)	Emissions (tons/yr) CO	NOx	SO2	THC	TSP	Total
663	AMOCO PRODUCTION CO	15	10.0	46	11,040	2.76	0.11	0.00	0.00	0.00	0.00	0.11
655	BAY OPERATING CO, INC.	15	10.0	46	11,040	2.76	0.11	0.00	0.00	0.00	0.00	0.11
590	BKN OIL & GAS, INC	43	3.5	132	31,680	7.92	0.30	0.00	0.00	0.00	0.00	0.30
590	BKN OIL & GAS, INC	50	3.0	153	36,720	9.18	0.35	0.00	0.00	0.00	0.00	0.35
590	BKN OIL & GAS, INC	40	3.8	123	29,520	7.38	0.28	0.00	0.00	0.00	0.00	0.28
590	BKN OIL & GAS, INC	35	4.3	107	25,680	6.42	0.25	0.00	0.00	0.00	0.00	0.25
590	BKN OIL & GAS, INC	13	11.5	40	9,600	2.40	0.09	0.00	0.00	0.00	0.00	0.09
590	BKN OIL & GAS, INC	32	4.7	98	23,520	5.88	0.22	0.00	0.00	0.00	0.00	0.22
590	BKN OIL & GAS, INC	68	2.2	209	50,160	12.54	0.48	1.00	0.00	0.00	0.00	1.48
195	BRISTOL RESOURCES CORP	16	9.4	49	11,760	2.94	0.11	0.00	0.00	0.00	0.00	0.11
197	BRISTOL RESOURCES CORP	32	4.7	98	23,520	5.88	0.22	0.00	0.00	0.00	0.00	0.22
8	BROWN CLIFFORD L, JR	25	6.0	77	18,480	4.62	0.18	0.00	0.00	0.00	0.00	0.18
214	BROWN, GEORGE R PRTRSHP	22	6.8	67	16,080	4.02	0.15	0.00	0.00	0.00	0.00	0.15
747	CAVALLA ENERGY EXPLORATION CO	43	3.5	132	31,680	7.92	0.30	0.00	0.00	0.00	0.00	0.30
64	COASTAL OIL & GAS CORP	40	3.8	123	29,520	7.38	0.28	0.00	0.00	0.00	0.00	0.28
905	COASTAL OIL & GAS CORP	74	2.0	227	54,480	13.62	0.52	1.00	0.00	0.00	0.00	1.52
628	CONVEST ENERGY CORP	15	10.0	46	11,040	2.76	0.11	0.00	0.00	0.00	0.00	0.11
792	CORPUS CHRISTI LEASEHOLDS, INC	4	37.5	12	2,880	0.72	0.03	0.00	0.00	0.00	0.00	0.03
723	CORPUS CHRISTI OIL & GAS CO	15	10.0	46	11,040	2.76	0.11	0.00	0.00	0.00	0.00	0.11
708	CORPUS CHRISTI OIL & GAS CO	8	18.8	25	6,000	1.50	0.06	0.00	0.00	0.00	0.00	0.06
104	EBB TIDE OIL CO	55	2.7	169	40,560	10.14	0.39	1.00	0.00	0.00	0.00	1.39
71	EBB TIDE OIL CO	4	37.5	12	2,880	0.72	0.03	0.00	0.00	0.00	0.00	0.03
752	HOUSTON OIL PROD ENT, INC	10	15.0	31	7,440	1.86	0.07	0.00	0.00	0.00	0.00	0.07
753	HOUSTON OIL PROD ENT, INC	29	5.2	89	21,360	5.34	0.20	0.00	0.00	0.00	0.00	0.20
102	KARBUHN OIL CO	46	3.3	141	33,840	8.46	0.32	0.00	0.00	0.00	0.00	0.32
184	LA PARRITA OIL & GAS, INC	12	12.5	37	8,880	2.22	0.08	0.00	0.00	0.00	0.00	0.08
582	LAMAR OIL & GAS, INC	70	2.1	215	51,600	12.90	0.49	1.00	0.00	0.00	0.00	1.49
111	MARSHALL PETROLEUM, INC	10	15.0	31	7,440	1.86	0.07	0.00	0.00	0.00	0.00	0.07
238	MERRICO RESOURCES, INC	34	4.4	104	24,960	6.24	0.24	0.00	0.00	0.00	0.00	0.24
206	MIDCON OFFSHORE, INC	10	15.0	31	7,440	1.86	0.07	0.00	0.00	0.00	0.00	0.07
119	M.K. MCDANIEL	44	3.4	135	32,400	8.10	0.31	0.00	0.00	0.00	0.00	0.31
645	OIL LEASE OPERATING CO	10	15.0	31	7,440	1.86	0.07	0.00	0.00	0.00	0.00	0.07
14	PI ENERGY, INC	20	7.5	61	14,640	3.66	0.14	0.00	0.00	0.00	0.00	0.14
4CCC	PI ENERGY, INC	75	2.0	230	55,200	13.80	0.53	1.00	0.00	0.00	0.00	1.53
638	PINELL, H P TRUSTEE	24	6.3	74	17,760	4.44	0.17	0.00	0.00	0.00	0.00	0.17
595	POYNOR CORP.	72	2.1	221	53,040	13.26	0.51	1.00	0.00	0.00	0.00	1.51
176	S.S.C. GAS PRODUCING CO	60	2.5	184	44,160	11.04	0.42	1.00	0.00	0.00	0.00	1.42
201	TIERRA MINERAL DEVELOPMENT	1	150.0	3	720	0.18	0.01	0.00	0.00	0.00	0.00	0.01
547	WAINOCO OIL & GAS CO	2	75.0	6	1,440	0.36	0.01	0.00	0.00	0.00	0.00	0.01
170	WESTLAND OIL DEVELOPMENT CORP	1	150.0	3	720	0.18	0.01	0.00	0.00	0.00	0.00	0.01
552	WILSON HYDROCARBON, INC	60	2.5	184	44,160	11.04	0.42	1.00	0.00	0.00	0.00	1.42
	TOTAL:	1,254	–	–	–	230.88	8.82	8.00	0.00	0.00	0.00	16.82

TEXAS MEDIUM/LARGE-VOLUME FACILITIES – GAS FLOTATION – BAT (PRODUCED WATER)

Permit No.	Operator	Current Volume (BPD)	Electric Power (hp)	Electric Power (hp-hr/yr)	Diesel Fuel Reqmt's (gal/yr)	Nat. Gas Power (hp)	Nat. Gas Power (hp-hr/yr)	Nat. Gas Fuel Reqmt's (MMscf/yr)	Emissions (tons/yr) CO	NOx	SO2	THC	TSP	Total
163	ACE PRODUCTIONS	450	12.3	107,874	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
136	AMERICAN EXPLORATION CO	4,476	21.4	187,460	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
666	AMERICAN EXPLORATION CO	335	12.1	105,601	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
19	APACHE CORP	1,685	15.1	132,288	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
590	BKN OIL & GAS, INC	2,436	16.8	147,133	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
684	BRANDES PETROLEUM INC	250	11.9	103,921	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
105	BROWN, CLIFFORD L, JR	2,370	16.6	145,829	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
90,113	BROWN, GEORGE R. PRTNRSHP	6,670	0	0	0	27.1	237,220	2.254	0.37	2.87	0.00	1.15	0.00	4.39
693	BRYMER CONTRACTING CO	436	12.3	107,598	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
673	BWS VACUUM SERVICE, INC.	130	11.6	101,549	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
60	CEDAR POINT OIL CO	1,200	14.0	122,700	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
675	TABBS BAY/GALVESTON BAY	210	11.8	103,130	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
857	CLARON CORP	175	11.7	102,438	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
904	COASTAL OIL & GAS CORP	4,839	22.2	194,636	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
616	CREST RESOURCES & EXPLOR	400	12.2	106,886	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
694	CREST RESOURCES & EXPLOR	180	11.7	102,537	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
710	DAN J HARRISON III&FH BRUCE	150	11.6	101,944	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
637	DENOVO OIL & GAS, INC	652	12.8	111,867	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
241	DEWBRE PETROLEUM CORP	155	11.6	102,043	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
649	DYNAMIC PRODUCTION, INC.	80	11.5	100,560	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
13	ENSENJAY PETROLEUM CORP	1,193	14.0	122,562	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
80	EXXON CORP	1,948	15.7	137,487	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
81	EXXON CO, USA	888	13.3	116,533	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
26	EXXON CORP – HOUSTON	7,495	0	0	0	29.2	255,974	2.432	0.39	3.10	0.00	1.24	0.00	4.73
202	FORT WORTH OIL AND GAS	84	11.5	100,639	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
89	GOODRICH OPERATING CO, INC	137	11.6	101,687	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
739	GRAHAM ROYALTY, LTD	330	12.0	105,502	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
635	GULF VACUUM SERVICE	1,290	14.2	124,479	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
627	HAPS OIL & GAS CORP	185	11.7	102,636	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
134	HEADINGTON OIL CO	400	12.2	106,886	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
885	HOUSTON OIL & MINERALS CORP	168	11.7	102,300	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
632	KANSAS OIL & GAS CO	904	13.3	116,849	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
152	KEPLINGER OPERATING CO	80	11.5	100,560	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
249	KILLAM OIL CO	3,755	19.8	173,207	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
122	KILMARNOCK OIL CO	200	11.8	102,932	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
672	KING OIL	120	11.6	101,351	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
587	LINDA PRODUCTION, INC	80	11.5	100,560	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
264	LIVE OAK RESERVES, INC	775	13.0	114,299	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
659	LONE OAK DISPOSAL CO	248	11.9	103,881	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
580	LUNDY VACUUM SERVICE, INC	100	11.5	100,956	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
207	MIRESCO, INC	1,033	13.6	119,399	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
1	NEUMIN PRODUCTION CO	88	11.5	100,718	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
68	ORANGE PETROLEUM CO	5,759	0	0	0	24.7	216,512	2.057	0.33	2.62	0.00	1.05	0.00	4.00
577	PATON OIL CORP	682	12.8	112,460	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
789	PAX PETROLEUM CORP	350	12.1	105,898	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
276	PEARL, BILL H. PROD, INC	375	12.1	106,392	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
166	PETRO VEST, INC	100	11.5	100,956	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
167	PETRO VEST, INC	400	12.2	106,886	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
242	PI ENERGY, INC	600	12.7	110,839	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
822	POYNOR CORP	1,000	13.6	118,747	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
282	REDFISH BAY OPERATING CORP	110	11.5	101,153	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
613	REDFISH BAY OPERATING CORP	600	12.7	110,839	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
744	SCANA EXPLORATION CO	1,200	14.0	122,700	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
127,132	SHELTON, CHARLES, H	574	12.6	110,326	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
685	SNR OILFIELD SERVICES, INC	600	12.7	110,839	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
124	S&S ENERGY, INC	783	13.1	114,457	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
674	TD OPERATING CO	200	11.8	102,932	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
20	TEXACO E & P INC	275	11.9	104,415	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
85	TEXACO E & P INC	112	11.6	101,193	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
155	TEXACO E & P, INC	1,660	15.0	131,794	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
156	TEXACO E & P, INC	2,746	17.5	153,261	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
157	TEXACO E & P, INC	479	12.4	108,448	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
854	TEXANA OPERATING CO	185	11.7	102,636	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
177	TEXAS PETROLEUM CO	1,500	14.7	128,631	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
189	TIERRA MINERAL DEVELOPMENT	2,045	15.9	139,404	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
165	UNION OIL CO OF CA	144	11.6	101,825	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
47	UNITED TEXAS CORP (A)	150	11.6	101,944	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
605	WHITTINGTON OPERATING CO	245	11.9	103,822	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
680	ZILKA ENERGY CO	110	11.5	101,153	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
219	ZINN PETROLEUM CO	300	12.0	104,909	0	0	0	0.000	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL:	72,064	--	--	0	--	--	6.742	1.090	8.590	0.000	3.440	0.000	13.120

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FUEL REQUIREMENTS AND AIR EMISSIONS FOR GAS FLOTATION – COOK INLET PRODUCED WATER

Facility/ Platform	PW Flow (peak bpd)	New IGF System ?	Gas. Hot. Cap. (bpd)	Total HP Req'd	Nat. Gas (MMscf/yr)	Total Power (hp-hr/yr)	Air Emissions (tons/yr)				
							NOx	CO	HC	SO2	Totals
Trading Bay	151,425	no	NA	0	0	0	0.000	0.000	0.000	0.000	0.000
Granite Point	1,000	yes	5,000	15.53	1.292	136,043	0.007	0.255	0.008	0.000	0.271
East Foreland	5,500	yes	10,000	20.5	1.706	179,580	0.010	0.336	0.011	0.000	0.357
Anna	2,000	yes	5,000	15.53	1.292	136,043	0.007	0.255	0.008	0.000	0.271
Baker	55	yes	1,000	12.25	1.019	107,310	0.006	0.201	0.007	0.000	0.214
Bruce	700	yes	1,000	12.25	1.019	107,310	0.006	0.201	0.007	0.000	0.214
Dillon	5,000	yes	10,000	20.5	1.706	179,580	0.010	0.336	0.011	0.000	0.357
Tyonek	478	yes	NA	0	0	0	0.000	0.000	0.000	0.000	0.000
TOTALS	**166,158**	--	--	**96.56**	**8.036**	**845,866**	**0.047**	**1.584**	**0.051**	**0.002**	**1.683**

FUEL REQUIREMENTS AND AIR EMISSIONS FOR ZERO DISCHARGE – COOK INLET PRODUCED WATER

Facility/ Platform	PW Flow (peak bpd)	Gas Hot.		Filtr.		Inj Pumps		HP Req'd (Other Pumps)	HP For All Equip.	Total Power (hp-hr/yr)	Nat. Gas (MMscf/yr)	Air Emissions (tons/yr)				
		Cap. (bpd)	HP	Cap.(bpd)	HP	Cap.(bpd)	HP					NOx	CO	HC	SO2	Total
Trading Bay	151,425	NA	0	NA	0	NA	NA	4,050	4,050.00	35,478,000	337.041	1.954	66.424	2.149	0.078	70.604
Granite Point	1,000	5,000	15.53	5,000	30	3,000	100	NA	145.53	1,274,843	12.111	0.070	2.387	0.077	0.003	2.537
East Foreland	6,240	10,000	20.5	NA	0	NA	NA	1,350	1,370.50	12,005,580	114.053	0.661	22.477	0.727	0.026	23.892
Anna	2,000	5,000	15.53	NA	0	NA	NA	NA	15.53	136,043	1.292	0.007	0.255	0.008	0.000	0.271
Baker	55	1,000	12.25	NA	0	1,000	42	NA	54.25	475,230	4.515	0.026	0.890	0.029	0.001	0.946
Bruce	700	1,000	12.25	NA	0	NA	NA	NA	12.25	107,310	1.019	0.006	0.201	0.007	0.000	0.214
Dillon	5,000	10,000	20.5	NA	0	NA	NA	NA	20.50	179,580	1.706	0.010	0.336	0.011	0.000	0.357
Tyonek	478	NA	0	1,000	15	1,000	42	NA	57.00	499,320	4.744	0.027	0.935	0.030	0.001	0.994
TOTALS	**166,898**	--	**96.56**	--	**45**	--	**184**	**5,400**	**5,725.56**	**50,155,906**	**476.481**	**2.762**	**93.904**	**3.038**	**0.110**	**99.815**

APPENDIX XVI-3

NEW SOURCE NWQ1S FOR PRODUCED WATER IN THE COASTAL GULF OF MEXICO AREA

Fuel Requirements

1.0 FUEL REQUIREMENTS

1.1 Small-Volume Facilities with Land Access

Avg. PW volume = 30.6 bpd (see Section XI)

No. of facilities = 1

Annual Vol. = 30.6 bbl/day x 365 days/yr = 11,169 bpy

No. trucks = $\frac{11{,}169 \text{ bbl/yr}}{119 \text{ bbl/truck}}$ = 94 trucks/yr

Fuel consumption - trucks = 94 trucks/yr x ¼ gal/mi x 120 mi/truck = 2,820 gal/yr

1.2 Small-Volume Facilities with Water Access

Avg. PW volume = 35.5 bpd (see Section XI)

No. facilities = 1

Annual vol. = 35.5 x 365 = 12,958 bbl/yr

No. barges = $\frac{12{,}958 \text{ bbl/yr}}{1{,}500 \text{ bbl/barge}}$ = 8.6 barge/yr

Fuel consumption - barge = 8.6 barge/yr x 100 mi/barge x 4 gal/mi = 3,440 gal/yr

Aux. Eq. = (1 hr/trip x 8.6 trips/yr x 6 gal/yr)+(0.6+3.5)gal/hr x (1.05 hr/trip x 8.6 trips/yr) = 89 gal/yr

1.3 Medium/Large-Volume Facilities with Land Access (Injection Only)

Flow = 838 bpd (see Section XI)

No. facilities = 1

HP = 0.0359 (flow) - 3.10 = 27 hp (Section 3)

HP-HR = 27 hp x 8,760 hrs/yr = 236,382 hp-hr/yr

NG = 236,382 hp-hr/yr x 9.5 scf/hp-hr = 2,245,625 scf/yr

1.4 Medium/Large-Volume Facilities with Water Access (Injection Only)

Flow = 3,355 bpd (see Section XI)

No. facilities = 3

HP = 0.0372 (flow) - 11.22 = 113.6 hp/fac.

Total HP = 113.6 x 3 = 340.8 hp

hp-hr/yr = 340.8 hp x 8,760 hrs/yr = 2,985,408 hp-hr/yr

NG = 2,985,408 hp-hr/yr x 9.5 scf/hp-hr = 28,361,376 scf/yr

Total nat. gas requirement = 2,245,625 + 28,361,376 = 30,607,000 scf/yr

2.0 SUMMARY NSPS EMISSIONS FOR INJECTION (TONS/YR)

	Fuel	NO_x	THC	SO_2	CO	TSP	Total
Barge	3,440 gal/yr (diesel)	0.67	0.029	0.049	0.135	0.057	0.94
Truck	2,820 gal/yr (diesel)	0.142	0.032	--	0.107	--	0.281
Aux. Equip.	89 gal/yr (diesel)	0.021	0.0015	0.0015	0.004	0.0015	0.03
Total for Diesel	6,349 gal/yr = 151 BOE/yr	0.833	0.0625	0.0505	0.246	0.0585	1.251
Nat'l Gas Eng.	30,607,000 scf/yr	39.03	15.612	0.007	4.968	--	59.617
Total Emissions		39.863	15.675	0.0575	5.214	0.0585	60.87

3.0 SUMMARY NSPS EMISSIONS FOR GAS FLOTATION (TONS/YR)

NWQI only those for small-volume facilities

Natural Gas based on 13.4 hp x 1 land-accessed facility = 13.4 hp

22.8 hp x 3 water-accessed facilities = 68.4 hp

Total hp = 13.4 + 68.4 = 81.8 hp

81.8 hp x 8,760 hrs/yr = 716,568 hp-hr/yr

Nat'l Gas = 9.5 x 716,568 = 6,807,396 scf/yr or 1,212 BOE/yr

	NO_x	THC	SO_2	CO	TSP	Total
Emissions from nat. gas (tons/yr)	8.68	3.472	0.002	1.105	0.0000	13.259
Emissions from diesel/(tons/yr)	0.833	0.0625	0.0505	0.246	0.0585	1.251
Total Emissions (tons/yr)	9.513	3.535	0.0525	1.351	0.0585	14.51

APPENDIX XVI-4

Baseline Air Emissions Data for an Average Production Facility in the Gulf of Mexico

TABLE 1
PROPORTION OF AIR EMISSIONS ASSOCIATED WITH ZERO DISCHARGE
AT THE TEXACO LEEVILLE CF #8 TANK BATTERY #4
BASED ON GAS PRODUCTION OF 1.5 MMCFD

SOURCE	NOX (tons/yr)	THC (tons/yr)	SO2 (tons/yr)	CO (tons/yr)	TSP (tons/yr)	TOTAL (tons/yr)
#11 INJ. PUMP(a)	9.198	0.307	0.002	1.188	0	10.7
#12 INJ. PUMP(a)	9.198	0.307	0.002	1.188	0	10.7
#13 SWD TANK(a)	0	0.623	0	0	0	0.6
TOTAL ZERO DISC.	18.396	1.237	0.004	2.376	0.000	22.0
TOTAL TANK BATTERY(b)	25.987	73.296	0.01	3.411	0.038	102.7
COMPRESSOR STATION(c)	79.358	1.321	0.006	4.601	0.001	85.3
TOTAL	105.345	74.617	0.016	8.012	0.039	188.0
ZERO DISC. % OF TOTAL	17.5%	1.7%	25.0%	29.7%	0.0%	

TOTAL EMISSIONS	
ZERO DISCHARGE	22.0
TOTAL	188.0
ZERO DISC. % OF TOTAL	11.7%
ZERO DISC. % INCREASE	13.3%

(a) BASED ON SECTION 3 OF ERCI JULY 1994
(b) BASED ON SECTION 1 OF ERCI JULY 1994
(c) BASED ON 10% OF THE EMISSIONS FROM A 15 MMCFD COMPRESSOR STATION (WALK HAYDEL, MAY 1994)

TABLE 2
PROPORTION OF AIR EMISSIONS ASSOCIATED WITH ZERO DISCHARGE
AT THE TEXACO LEEVILLE CF #8 TANK BATTERY #4
BASED ON GAS PRODUCTION OF 2.65 MMCFD

SOURCE	NOX (tons/yr)	THC (tons/yr)	SO2 (tons/yr)	CO (tons/yr)	TSP (tons/yr)	TOTAL (tons/yr)
#11 INJ. PUMP(a)	9.198	0.307	0.002	1.188	0	10.7
#12 INJ. PUMP(a)	9.198	0.307	0.002	1.188	0	10.7
#13 SWD TANK(a)	0	0.623	0	0	0	0.6
TOTAL ZERO DISC.	18.396	1.237	0.004	2.376	0.000	22.0
TOTAL TANK BATTERY(b)	25.987	73.296	0.01	3.411	0.038	102.7
COMPRESSOR STATION(c)	140.199	2.334	0.011	8.128	0.002	150.7
TOTAL	166.186	75.63	0.021	11.539	0.04	253.4
ZERO DISC. % OF TOTAL	11.1%	1.6%	19.0%	20.6%	0.0%	

TOTAL EMISSIONS	
ZERO DISCHARGE	22.0
TOTAL	253.4
ZERO DISC. % OF TOTAL	8.7%
ZERO DISC. % INCREASE	9.5%

(a) BASED ON SECTION 3 OF ERCI JULY 1994
(b) BASED ON SECTION 1 OF ERCI JULY 1994
(c) BASED ON 17.7% OF THE EMISSIONS FROM A 15 MMCFD COMPRESSOR STATION (WALK HAYDEL, MAY 1994)

TABLE 3
GOLDEN MEADOW COMPRESSOR STATION #1
AIR EMISSIONS CALCULATIONS

GAS RATE (MMcfd)	% OF TOTAL	NOX (tons/yr)	THC (tons/yr)	SO2 (tons/yr)	CO (tons/yr)	TSP (tons/yr)	TOTAL (tons/yr)
15	100.0%	793.582	13.211	0.063	46.007	0.014	852.9
1.5	10.0%	79.358	1.321	0.006	4.601	0.001	85.3
2.65	17.7%	140.199	2.334	0.011	8.128	0.002	150.7

SOURCE: WALK HAYDEL, MAY 1994

APPENDIX XVI-5

NWQI Spreadsheets for TWC Fluids in the Gulf of Mexico

Non-Water Quality Impacts for Treatment, Workover, and Completion Fluids in the Gulf of Mexico Coastal Region

All NWQI calculations in this appendix pertain to small-volume facilities, as identified in Section XI of the Development Document. Based on the assumptions presented in Section XII, all TWC fluids at medium/ large-volume facilities are commingled with produced water and do not contribute to NWQIs.

1. EXISTING SOURCES (BAT OPTIONS)

1.1 Treatment/Workover Fluids

1.1.1 Water-Access Facilities

Input Data:

• No. barge trips per year (Appendix XII-1):	53
• Average round-trip distance (Appendix XI-1):	100 miles
• Fuel consumption - tug (Wiedeman, June 30, 1992):	24 gal/hr
• Traveling speed (Appendix XI-1):	6 miles/hr
• Time to dock per trip (Appendix XI-1):	1 hr
• Barge capacity (Sect. XII.3.1.3):	1,500 bbls
• Pumping rate for 4-inch vacuum pump (Brazzel, Nov. 12, 1992):	60,000 gal/hr
• Time to unload barge = (1,500 bbls x 42 gal/bbl)/60,000 gph =	1.05 hrs

- While loading and unloading, the tug engine is shut down. During loading, the auxilliary generator is running. Loading is accomplished by gravity. Unloading is accomplished by vacuum pump. Thus:

Aux. generator fuel consumption (Wiedeman, Jan. 1993):	6 gal/hr
Vacuum pump fuel consumption (Brazzel, Nov. 12, 1992):	0.6 gal/hr
Compressor fuel comsumption (Wiedeman, June 30, 1992):	3.5 gal/hr

Calculations:

- Tug and barge transit fuel consumption:

Diesel: 53 trips/yr x 100 mi/trip x 24 gal/hr x (1hr/6mi) = 21,200 gal/yr

- Aux. equipment fuel consumption:

(1hr/trip x 53 trips/yr x 6 gal/hr) + (4.1 gal/hr x 1.05 hr/trip x 53 trips/yr) = 546 gal/yr

1.1.2 Land-Access Facilities

Input Data:

- Number of jobs per year (Appendix XII-1): 28
- Total volume of treatment/workover fluids per job (Appendix XII-1): 587 bbls
- Vacuum truck capacity (Section XI.3.1): 119 bbls
- Average round-trip distance from each discharging facility to commercial disposal facility (Appendix XI-1): 120 miles
- Truck diesel usage (EPA, Jan. 13, 1993): 4 miles/gal

Calculations:

- Total volume of treatment/workover fluids:

  587 bbls/job x 28 jobs/yr = 16,436 bbls/yr

- Number of trucks per year:

  (16,436 bbls/yr) / (119 bbls/truck) = 138 trucks/yr

- Fuel consumption - trucks:

  138 trucks/yr x (1 gal/4 miles) x 120 miles/truck = 4,144 gal/yr

1.1.3 Summary NWQIs for Workover/Treatment Fluids from Existing Sources

Consumer	Diesel Usage (gal/yr)	NOx (tons/yr)	THC (tons/yr)	SO_2 (tons/yr)	CO (tons/yr)	TSP (tons/yr)	TOTAL
Aux. Equip. (Water-Access Sites)	546	0.128	0.01	0.009	0.028	0.009	0.184
Barge	21,200	4.152	0.178	0.302	0.830	0.350	5.812
Truck	4,144	0.209	0.046	--	0.158	--	0.413
TOTAL	25,890	4.489	0.234	0.311	1.016	0.359	6.409

1.2 Completion Fluids

1.2.1 Water-Access Facilities

Input Data:

- No. barge trips per year (Appendix XII-1): 50
- All other input data are the same as for treatment/workover fluids.

Calculations:

- Tug and barge transit fuel consumption:

  Diesel: 50 trips/yr x 100 mi/trip x 24 gal/hr x (1hr/6mi) = 20,000 gal/yr

- Aux. equipment fuel consumption:

  (1hr/trip x 50 trips/yr x 6 gal/hr) + (4.1 gal/hr x 1.05 hr/trip x 50 trips/yr) = 515 gal/yr

1.2.2 Land-Access Facilities

Input Data:

- Number of jobs per year (Appendix XII-1): 26
- Total volume of completion fluids per job (Appendix XII-1): 209 bbls
- All other input data are the same as for treatment/workover fluids.

Calculations:

- Total volume of completion fluids:

  209 bbls/job x 26 jobs/yr = 5,434 bbls/yr

- Number of trucks per year:

  (5,434 bbls/yr) / (119 bbls/truck) = 45.7 trucks/yr

- Fuel consumption - trucks:

  45.7 trucks/yr x (1 gal/4 miles) x 120 miles/truck = 1,371 gal/yr

1.2.3 Summary NWQIs for Completion Fluids from Existing Sources

Consumer	Diesel Usage (gal/yr)	NOx (tons/yr)	THC (tons/yr)	SO_2 (tons/yr)	CO (tons/yr)	TSP (tons/yr)	TOTAL
Aux. Equip. (Water-Access Sites)	515	0.121	0.0096	0.008	0.026	0.0086	0.1732
Barge	20,000	3.917	0.168	0.285	0.783	0.330	5.483
Truck	1,371	0.069	0.015	--	0.052	--	0.136
TOTAL	21,886	4.107	0.1926	0.293	0.861	0.3386	5.792

2. NEW SOURCES (NSPS OPTIONS)

2.1 Treatment/Workover Fluids

2.1.1 Water-Access Facilities

Input Data:

- No. barge trips per year (Appendix XII-1): 7
- All other input data are the same as in Section 1.1.1 above.

Calculations:

- Tug and barge transit fuel consumption:

  Diesel: 7 trips/yr x 100 mi/trip x 24 gal/hr x (1hr/6mi) = 2,800 gal/yr

- Aux. equipment fuel consumption:

  (1hr/trip x 7 trips/yr x 6 gal/hr) + (4.1 gal/hr x 1.05 hr/trip x 7 trips/yr) = 72 gal/yr

2.1.2 Land-Access Facilities

Input Data:

- Number of jobs per year (Appendix XII-1): 4
- All other input data are the same as in Section 1.1.2 above.

2.1.2 Land-Access Facilities (cont.)

Calculations:

- Total volume of completion fluids:

  209 bbls/job x 4 jobs/yr = 2,348 bbls/yr

- Number of trucks per year:

  (2,348 bbls/yr) / (119 bbls/truck) = 19.7 trucks/yr

- Fuel consumption - trucks:

  19.7 trucks/yr x (1 gal/4 miles) x 120 miles/truck = 592 gal/yr

2.1.3 Summary NWQIs for Treatment/Workover Fluids from New Sources

Consumer	Diesel Usage (gal/yr)	NOx (tons/yr)	THC (tons/yr)	SO_2 (tons/yr)	CO (tons/yr)	TSP (tons/yr)	TOTAL
Aux. Equip. (Water-Access Sites)	72	0.017	0.0015	0.001	0.0035	0.001	0.024
Barge	2,800	0.549	0.0235	0.040	0.1095	0.046	0.768
Truck	592	0.030	0.0062	--	0.0226	--	0.059
TOTAL	3,464	0.596	0.0312	0.041	0.1356	0.047	0.851

2.2 Completion Fluids

2.2.1 Water-Access Facilities

Input Data:

- No. barge trips per year (Appendix XII-1): 7
- All other input data are the same as in Section 1.1.1 above.

Calculations:

- Tug and barge transit fuel consumption:

  Diesel: 7 trips/yr x 100 mi/trip x 24 gal/hr x (1hr/6mi) = 2,800 gal/yr

- Aux. equipment fuel consumption:

  (1hr/trip x 7 trips/yr x 6 gal/hr) + (4.1 gal/hr x 1.05 hr/trip x 7 trips/yr) = 72 gal/yr

2.2.2 Land-Access Facilities

Input Data:

- Number of jobs per year (Appendix XII-1): 4
- Total volume of completion fluids per job (Appendix XII-1): 209 bbls
- All other input data are the same as in Section 1.1.1.

Calculations:

- Total volume of completion fluids:

  209 bbls/job x 4 jobs/yr = 836 bbls/yr

- Number of trucks per year:

  (836 bbls/yr) / (119 bbls/truck) = 7 trucks/yr

- Fuel consumption - trucks:

  7 trucks/yr x (1 gal/4 miles) x 120 miles/truck = 211 gal/yr

2.2.3 Summary NWQIs for New Source Completion Fluids from New Sources

Consumer	Diesel Usage (gal/yr)	NOx (tons/yr)	THC (tons/yr)	SO_2 (tons/yr)	CO (tons/yr)	TSP (tons/yr)	TOTAL
Aux. Equip. (Water-Access Sites)	72	0.017	0.0015	0.001	0.0035	0.001	0.024
Barge	2,800	0.549	0.0235	0.040	0.1095	0.046	0.768
Truck	211	0.011	0.0023	--	0.0080	--	0.021
TOTAL	3,083	0.577	0.0273	0.041	0.121	0.047	0.813