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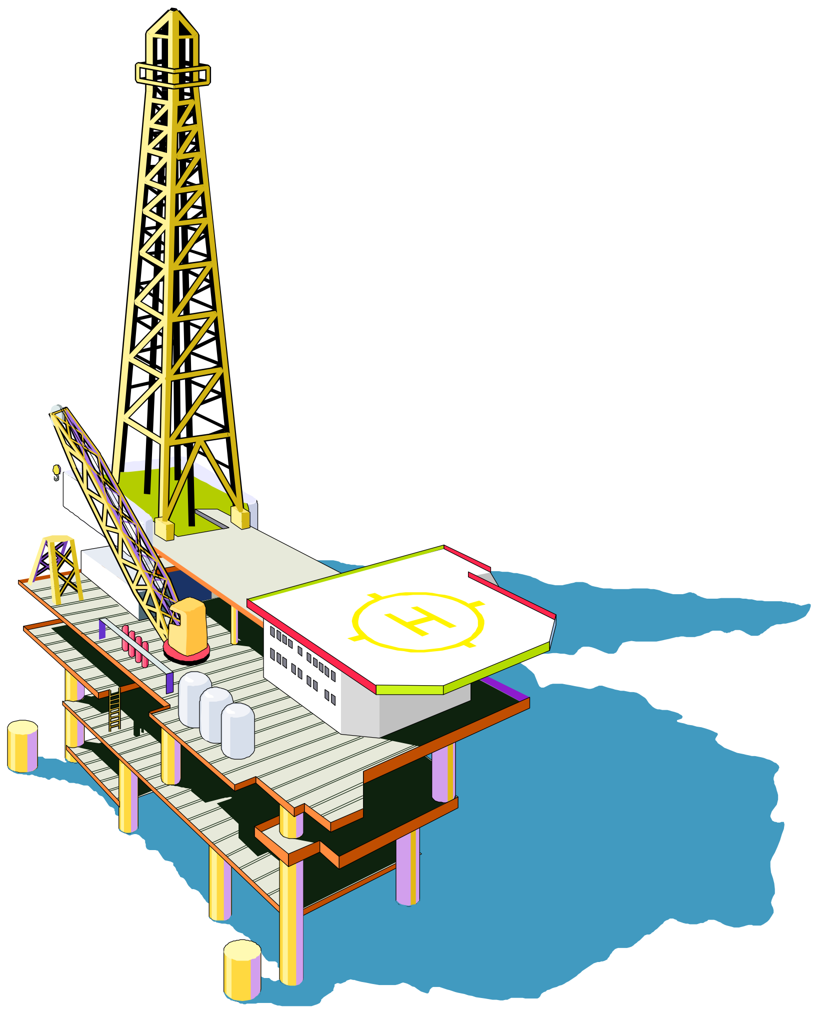
Economic Analysis of Proposed Effluent Limitations Guidelines and Standards for Synthetic-Based Drilling Fluids and Other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category



ECONOMIC ANALYSIS OF PROPOSED EFFLUENT LIMITATIONS GUIDELINES AND STANDARDS FOR SYNTHETIC-BASED DRILLING FLUIDS AND OTHER NON-AQUEOUS DRILLING FLUIDS IN THE OIL AND GAS EXTRACTION POINT SOURCE CATEGORY

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SECTION ONE

INTRODUCTION

The U.S. Environmental Protection Agency (EPA) is proposing to regulate the discharge of synthetic based drilling fluids (SBFs) and other non-aqueous drilling fluids and the resultant contaminated drill cuttings from drilling operations. This Economic Analysis (EA) report is written to address the impacts of this proposed Effluent Limitation Guidelines and Standards for Synthetic-Based and Other Non-Aqueous Drilling Fluids. Currently, effluent guidelines pertaining to the discharge of drilling fluids address two specific types of fluids:

- Oil-based drilling fluids (OBFs) that use diesel and mineral oil, which are prohibited from being discharged.

- Water-based drilling fluids (WBFs), which can be discharged subject to meeting certain discharge requirements, including a sheen test and an aqueous toxicity test, in certain limited offshore regions.

In many cases, SBFs and SBF-contaminated cuttings are not clearly prohibited from discharge, nor are they clearly allowed to be discharged, since the relevant effluent guidelines that define allowable conditions for discharge of drilling fluids and cuttings were developed before SBFs and other non-aqueous drilling fluids were widely available. To address this lack of clarity in existing effluent guidelines and to more clearly define allowable discharge conditions for SBF and other non-aqueous drilling wastes, EPA is proposing these Effluent Limitations Guidelines and Standards for Synthetic-Based and Other Non-Aqueous Drilling Fluids (known hereafter as the SBF Guidelines; where this report uses the term SBF, other non-aqueous fluids and associated cuttings are included in this term). These guidelines are being proposed as part of an expedited rulemaking process and thus the analyses in this report rely on publicly available or industry-provided data exclusively.

The SBF Guidelines would control the discharge of SBF-contaminated drill cuttings (SBF-cuttings). Discharge of the fluids themselves would be prohibited. Furthermore, the SBF guidelines would only apply where discharge of drilling waste is currently allowed. Because drilling fluids and cutting may only be discharged in a portion of offshore areas, the operations that might be affected by this proposed rulemaking would be limited to a subset of the U.S. oil and gas industry. EPA subdivides the oil and gas extraction point source category into several major subcategories, including the Onshore Subcategory, the Stripper Subcategory (marginal producing wells), the Beneficial Use Subcategory (wells whose produced water can be used beneficially for irrigation or other purposes), the Coastal Subcategory (wells located in water located landward of the territorial seas and associated wetlands), and the Offshore Subcategory (see 40CFR Part 435 for more details on the subcategorization of the oil and gas extraction point source category). Discharge of drilling fluids or drill cuttings into surface waters is completely prohibited for the Onshore, Stripper and Beneficial Use Subcategories, no matter what the composition of the fluid, as is the discharge of any drilling fluid in regions defined as coastal, with the exception of Cook Inlet, Alaska. Furthermore, discharge of any type of drilling fluid also is prohibited within 3 miles of shore in the Offshore region except Offshore Alaska, where there is no distance restriction.

Currently, the potentially affected offshore regions where drilling activity is taking place include the Gulf of Mexico, California, and Alaska. Drilling activity is also underway in the coastal region of Cook Inlet, Alaska. Outside of these regions, significant amounts of drilling activity are very unlikely to occur or discharge of drilling waste is prohibited.[1] Therefore, the focus of the industry profile and the analyses in this EA is on:

- The Federal Outer Continental Shelf (OCS) region of the Gulf of Mexico and the state waters off Texas between 3 miles and 3 leagues (Texas defines state waters out to 3 leagues, unlike most other states).
- The Federal Offshore region farther than 3 miles from the California shore.
- The Coastal Subcategory Region of Upper Cook Inlet, Alaska
- All Alaska Offshore areas.

Drilling operations in all these regions are investigated to determine how these operations would be affected by the proposed rule.

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[1]See discussions in the *Economic Impact Analysis of Final Effluent Limitations Guidelines and Standards of Performance for the Offshore Oil and Gas Industry*, U.S. EPA, 1993, EPA-821/R-93.001, and the *Economic Impact Analysis of Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category*, U.S. EPA 1995, EPA 821/R95.013.

This report is divided into seven sections. Following this introduction, Section Two presents sources of data, Section Three presents the industry profile, Section Four discusses the regulatory costs of options under consideration for the proposed rulemaking, and Section Five discusses the impacts of the proposed rule on firms, well drilling, and production, and also briefly discusses secondary impacts such as those on employment, output, inflation, balance of trade and other industries. Section Six presents EPA's initial regulatory flexibility analysis as required under the Regulatory Flexibility Act (RFA) as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA). Section Seven provides a brief summary of costs and benefits of the rule. Finally Appendix A documents how the per-well incremental costs were derived from EPA's engineering cost estimates, and Appendix B presents numbers of wells estimated to be drilled annually by potentially affected firms and the resulting compliance costs associated with those firms.

SECTION TWO

SOURCES OF DATA

As discussed in Section One, EPA has undertaken an expedited approach to this proposed rule. This means that EPA is not using a survey authorized under the Clean Water Act (Section 308 Survey) but instead is relying on public data and data that industry has submitted on a voluntary basis. This section discusses the primary sources of data used throughout this document. Certain additional references are cited where they occur in the document.

EPA is relying on information developed by Minerals Management Service (MMS) for EPA. This information includes wells drilled in federal waters during 1995, 1996, and 1997, along with the MMS-assigned numbers identifying the operators. These data were summarized by MMS from MMS's Technical Information Management System (TIMS). MMS grouped wells by location (Pacific and Gulf drilling operations were tallied separately), water depth (up to 999 ft and 1,000 ft or more), and by type (exploratory or development). MMS also provided a list of operators by operator number. EPA linked the name of the operators to wells drilled using the operator number. Names of all operators who had drilled any well in any of the three years were then compiled. EPA used the Security and Exchange Commission's (SEC's) Edgar database, which provides access to various filings by publicly held firms, such as 8Ks and 10Ks. The former documents are useful for determining mergers and acquisitions in more detail, and 10Ks provide annual balance sheet and income statements, as well as listing corporate subsidiaries. The information in the Edgar database was used to identify parent companies or recent changes of ownership. EPA also used a database maintained by Dun & Bradstreet (D&B), to which EPA subscribes, which provides estimates of employment and revenue for many privately held firms. This database is the U.S. EPA Facility Index System Dun & Bradstreet Detail and is referenced in this document as the D&B database. EPA also relied on financial data compiled by *Oil and Gas Journal* (OGJ) in two articles collectively known as the "OGJ 200 Report" in the issue: "OGJ 200 Companies Posted Strong Financial Year in 1997" and "Government Oil Companies Dominate OGJ 100 List of Production Leaders Outside U.S." These articles provided financial data on publicly held U.S. and foreign firms. This EA references the OGJ 200 Report as OGJ 200.

Other sources of data used in the economic analyses include:

- *Development Document for Proposed Effluent Guidelines and Standard for Synthetic-Based Drilling Fluids and Other Non-Aqueous Drilling Fluid in the Oil and Gas Extraction Point Source Category,* U.S. EPA, 1999 (EPA-821-B-98-021) (hereinafter known as the SBF Development Document). This document supports this proposed rulemaking and presents all cost data.

- *Economic Impact Analysis of Final Effluent Limitations Guidelines and Standards of Performance for the Offshore Oil and Gas Industry* (hereinafter known as Offshore EIA) (EPA 821/R-93.004) EPA, 1993

- *Economic Impact Analysis of Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category* (hereinafter known as Coastal EIA) (EPA 821/R95.013), EPA, 1995.

- *The Joint Association Survey on 1996 Drilling Costs*, published by the American Petroleum Institute (API), November, 1997 (hereinafter known as the Joint Association Survey). This document was used to determine baseline costs of drilling wells in the various offshore regions potentially affected by the rule.

- *USA Oil Industry Directory, 37th Edition,* PennWell Publishing Co., 1998 (hereinafter known as PennWell Directory), was used to provide additional information on potentially affected firms.

Additional sources are cited in detail where they are mentioned in this report.

SECTION THREE

PROFILE OF AFFECTED OFFSHORE DRILLING OPERATIONS

3.1 INTRODUCTION

This profile focuses on the drilling activity taking place in the Offshore regions of the Gulf of Mexico, California, and Alaska where discharge of drilling fluids with controls is authorized.[1] As discussed in Section One, the key areas include the Federal OCS region of the Gulf of Mexico and the state waters off Texas between 3 miles and 3 leagues, the California Federal OCS, the Coastal Subcategory region of Upper Cook Inlet, Alaska, and all Alaska Offshore areas. This section first discusses the processes of oil and gas drilling and the wastes created. It then presents current practices regarding use of OBFs, platforms, operators, and drilling activity in the regions of interest: Gulf of Mexico, California, Alaska Coastal, and Alaska Offshore.

3.2 PROCESSES OF OFFSHORE OIL AND GAS EXPLORATION AND DEVELOPMENT DRILLING AND THE WASTES GENERATED

3.2.1 Exploratory, Developmental, and Other Drilling

The two primary types of drilling operations conducted as part of the oil and gas extraction process are exploratory and developmental. Exploratory operations involve drilling wells to determine potential hydrocarbon reserves. Once a hydrocarbon reserve has been discovered and delineated, development wells are drilled for production. Although the rigs used for each type of drilling can differ, the drilling process is generally the same.

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[1]Other operations related to oil and gas drilling, including drilling fluid suppliers, solids control equipment rental firms, and waste transport and disposal firms, which may experience indirect impacts as a result of the rule, are discussed briefly in Section Five when secondary impacts on these operations are analyzed.

In the initial phases of exploration, wells usually are drilled to discover the presence of oil and gas reservoirs. Deeper wells subsequently are drilled to establish the extent of a reservoir (delineation). Exploration activities are usually of short duration, involve a small number of wells, and are conducted from mobile drilling rigs.

Other than being conducted to begin extracting recently discovered reserves of hydrocarbons, development drilling also is conducted to increase production or to replace nonproducing wells on existing production sites. Since development wells tend to be smaller in diameter than exploratory wells less waste is generated.[2]

3.2.2 Drilling Rigs

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

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

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

[2] *Development Document for the Final Effluent Limitation Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category*, EPA, 1996.

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

Drill ships and ship-shaped barges are vessels equipped with drilling rigs that float on the surface of the water. These vessels maintain position above the drill site by anchors on the seafloor or the use of propellers mounted fore, aft, and on both sides of the vessel (dynamic positioning). Drill ships are the other major drilling rig used in ultra-deep Gulf waters. In these locations, drill ships typically operate using dynamic positioning.[3] Drill ships and ship-shaped barges are susceptible to wave motion since they float on the surface of the water, and thus are not suitable for use in heavy seas.

Development wells are often drilled from fixed platforms because once exploratory drilling has confirmed that an extractable quantity of hydrocarbons exists, a platform is constructed at that site for drilling and production operations. Frequently, directional drilling is conducted to access different parts of a geological formation from a fixed location such as a platform. This type of drilling involves drilling the top part of the well straight down and then directing the wellbore to the desired location.

3.2.3 Description of Drilling Operations

In the drilling process, drillers use a rotating drill bit attached to the end of a drill pipe, referred to as the “drill string.” Circulating fluid (i.e., drilling fluid or mud) is used to move drill cuttings (bits of rock) away from the bit and out of the borehole. This fluid is frequently a mixture of water and/or various types of oils, special clays, and certain minerals and chemicals that is pumped “downhole” through the drill string and

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[3] Drilling Contractor, 1997. “Survey Measures Growth of Ultra Deep-Water Fleet,” pg. 18, November 1997.

ejected through the nozzles in the drill bit at high speeds and at high pressure. The jets of drilling fluid lift the cuttings from the bottom of the hole and away from the bit so the cuttings do not interfere with the effectiveness of the drill bit. The drilling fluid circulates and rises to the surface through the space between the drill string and the casing, called the annulus. As the wellbore deepens, the walls of the hole tend to cave in and widen; thus, periodically the drill string musty be lifted out so that a casing, which is a tube-shaped liner, can be placed in the hole. Cement is then is pumped into the space between the casing and the hole wall to secure the casing. Each new portion of casing must be smaller in diameter than the previous portion to allow for installation. The process of drilling and adding sections of casing continues until final well depth is reached. Figure 3-1 shows a typical drilling fluids circulation system.

3.2.4 Drilling Fluids and Drill Cuttings

3.2.4.1 Types of Drilling Fluids

WBFs are the most commonly used drilling fluids, but OBFs occasionally must be used such as when directional drilling is performed or when stuck pipe must be freed. OBFs also might be used in certain intervals or below certain depths. Diesel oil- or mineral oil-based OBFs are becoming less common primarily due to discharge prohibitions and toxicity limitations on the waste fluids and cuttings generated during OBF drilling. These fluids contain diesel or mineral oil as well as other constituents similar to those used in WBFs. In some locations, such as in the Gulf of Mexico, use of OBFs can be markedly reduced by the use of newer SBFs and other water non-dispersible drilling fluids. These SBFs have technical performance properties and uses similar to traditional OBFs, but might have significantly reduced toxicities relative to OBFs. The key advantage of SBFs is that cuttings associated with these fluids appear to pass limits on crude contamination and toxicity and are currently being discharged in many Gulf locations instead of being barged to shore for disposal at a possibly significant cost savings. The SBFs are, like traditional OBFs, invert emulsions, meaning that they are oils with water mixed in, but their base fluid differs from OBFs. SBF oils, or base fluids, can be vegetable esters, linear alpha olefins, internal olefins, or others currently in development or theoretically usable. Another group considered in the “other water non-dispersible fluids” group, include the enhanced mineral oils, which are highly refined mineral oils in which the major toxic components have been removed. Finally there is the group of synthetic and nonsynthetic paraffinic oils.

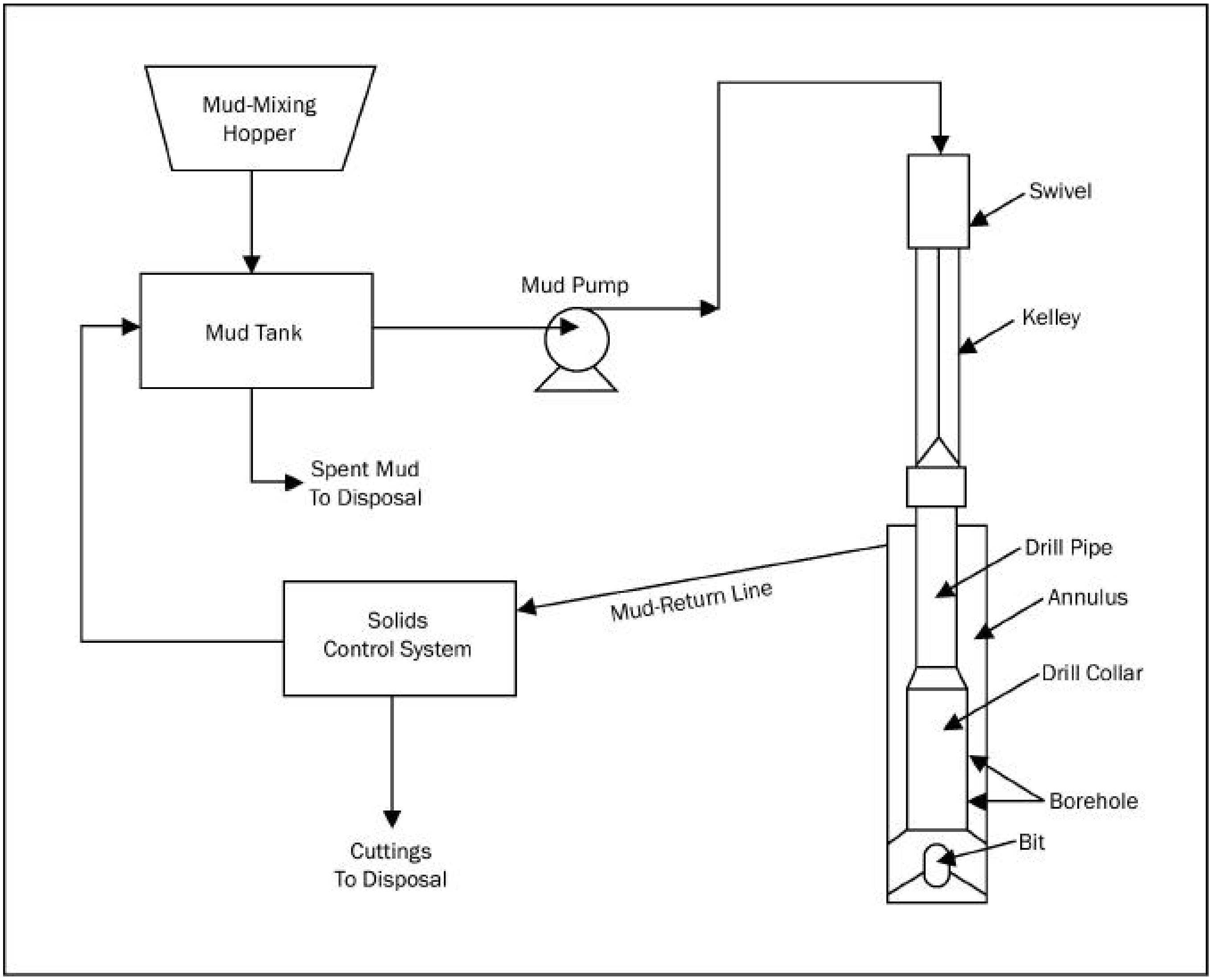

Figure 3-1. Typical drilling fluids circulation system.

3.2.4.2 Drilling Wastes

Drilling fluids and drill cuttings become wastes at different stages of the well drilling process. Drill cuttings are generated throughout the drilling project, although higher quantities of cuttings are generated when drilling the first few thousand feet of the well because the borehole is the widest during this stage. In contrast, the largest quantities of excess drilling fluids are generated as the project approaches final well depth. Most waste fluid is generated at completion of well drilling because the entire drilling fluid system must be removed from the hole and the tanks used to hold the drilling fluid. Some constituents can be recovered after completion of the drilling, either at the rig or by the supplier of the drilling fluid. Typically, OBFs and SBFs are recovered for recycling and waste fluid per se is not generated. A certain amount of the OBF or SBF remains adhered to the drill cuttings, however, and so is disposed of as a contaminant of the cuttings.[4] When drilling is continuous, such as at certain platforms, drilling fluid can be reused to drill the next well in a series. The following sections discuss the two types of wastes in more detail.

Cuttings

Drill cuttings are a major portion of the wastestream generated by the drilling process. At the well's surface, the cuttings, along with silt, sand, and any gases, are removed from the drilling fluid before the drilling fluid is returned downhole to the bit. The cuttings, silt, and sand are separated from the drilling fluid by a solids separation process. This process typically involves shale shakers, desilters, desanders, and centrifuges (each removing sequentially smaller waste particles from the drilling fluid). Some of the drilling fluid remains adhered to the cuttings after solids separation. If the cuttings, silt, sand, and any residual drilling fluid clinging to the cuttings do not contain free oil or other regulated contaminants and they meet the specific requirements for discharge they may be discharged in certain portions of the Offshore and Coastal subcategories defined above. To meet requirements of the proposed SBF Guidelines (see Section Four), operators might need to add onto their usual solids separation equipment. An add-on technology that EPA investigated as part of the rulemaking process is a vibratory centrifuge, which processes the larger cuttings from the primary shale shakers. This process is described in the SBF Development Document in more detail.

[4]SBF Development Document.

This type of system can achieve a high removal rate (and thus a low retention rate) of residual fluid on cuttings.

Drilling Fluid

Drilling fluid itself can also become a waste. Drilling fluid can become contaminated, and thus constitute a waste, during several different stages of the drilling process. Additionally, drilling fluid can become a waste if it cannot be adjusted to provide the required flow properties, lubricity, or wellbore stabilization. When a drilling fluid no longer meets the technical requirements or the operator decides that it is advantageous to change to a new drilling fluid system, a “mud changeover” is performed. The drilling fluid system replaced can become a waste at this stage if it is not recycled or reused later in the drilling process. OBFs and SBFs are recycled because of the expense of the fluid and because of disposal considerations. Any drilling waste or cuttings to be discharged must first be tested for sheen (which indicates the level of hydrocarbon contamination of the fluid or cuttings) and also must be tested for toxicity. As noted in Section Two, EPA is assessing additional tests and controls on SBF and SBF-cuttings discharge as part of this rulemaking.

Very small drill cuttings called “fines” can build up in the drilling fluid, increasing the drilling fluid solids and spoiling the flow properties of the drilling fluid. If drilling fluid solids cannot be controlled efficiently, dilution with fresh drilling fluids might be necessary to reduce the solids content of the circulating drilling fluid system, in which case the displaced drilling fluid can become a waste. More recently developed solids control systems are much more efficient than older systems. Thus, waste drilling fluid stemming from the need to displace fluid that has become overloaded with fine solids is now less of a problem. Furthermore these systems are able to separate and recycle more fluid from the waste cuttings, reducing the amount of drilling fluid adhering to the cuttings, further reducing contaminants such as free oil and toxics. Very recent advances in the area of solids control incorporate the use of a vibrating centrifuge in the drilling fluid recovery system. These types of systems are able to remove and recycle such a large portion of drilling fluid that EPA is considering the use of these systems as part of the SBF Guidelines options (see Section Four).

3.3 PROFILE OF THE AFFECTED REGIONS

3.3.1 Gulf of Mexico Beyond Three Miles from Shore

The Gulf of Mexico beyond 3 miles from shore is the most active of the four oil and gas regions of interest. Nearly all exploration and development activities in the Gulf are taking place in the Western Gulf of Mexico, that is, the regions off the Texas and Louisiana shores. Very little drilling is occurring off Mississippi, Alabama, and Florida.

3.3.1.1 Current Practices

The Gulf of Mexico is the location of the majority of the drilling activity currently occurring in the regions affected by this proposed rulemaking. This region also is associated with the only known current use of SBF and discharge of SBF-cuttings. SBFs are used preferentially in drilling deeper formations, in deeper water, in formations of reactive shale, and during directional drilling. They generally replace traditional OBFs for these purposes.

3.3.1.2 Platforms

EPA updated its count of active platforms in the federal OCS region of the Gulf of Mexico that was originally presented in the Offshore EIA, using the most recent version of the MMS Platform Inspection System, Complex/Structure database as of May, 1998. The database was downloaded and counts of structures were noted. Abandoned structures, platforms considered production facilities only, platforms with no productive wells, platforms with missing production data, and platforms with service wells only were counted and removed from totals, in the same way as was done for the Offshore Effluent Guidelines.[5] Out of a total of 5,026 structures, EPA identified 2,381 platforms that fit this description (see Table 3-1).

[5]Offshore EIA.

Table 3-1
Identification of Structures in the Gulf of Mexico OCS

Category	Count	Remaining Count
All structures	5026	5026
Abandoned structures	1403	3623
Structures classified as production structures, i.e. with no well slots and with production equipment	245	3378
Structures known not to be in production	688	2690
Structures with missing information on product type (oil or gas or both)	309	2381
Structures whose drilled well slots are used solely for injection, disposal, or as a water source	0	2381

Source: MMS, 1998. Platform Inspection System, Complex/Structure.

3.3.1.3 Operators

The expenditures required to comply with the SBF Guidelines will be financed by the affected firms and their investors. Affected firms can be divided into two basic categories. The first category consists of the major integrated oil companies, which are characterized by a high degree of vertical integration (i.e., their activities encompass both "upstream" activities—oil exploration, development, and production—and "downstream" activities—transportation, refining, and marketing). The second category of affected firms consists of independents engaged primarily in exploration, development, and production of oil and gas and not typically involved in downstream activities. Some independents are strictly producers of oil and gas, while others maintain some service operations, such as contract drilling and well servicing. The major integrated oil companies are generally larger than the independents. As a group, the majors typically produce more oil and gas, earn significantly more revenue and income, and have considerably more assets and greater financial resources than most independents. Furthermore, majors tend to be relatively homogeneous in terms of size and corporate structure. All majors are considered large firms under the Regulatory Flexibility Act (RFA) guidelines and generally are C corporations (i.e., the corporation pays income taxes).

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

For this profile, EPA is relying on information developed by MMS for EPA that includes wells drilled in federal waters during 1995, 1996, and 1997, along with the identification number of the operator. These data were summarized from MMS's Technical Information Management System (TIMS). MMS grouped wells by location (Pacific and Gulf drilling operations were tallied separately), water depth (up to 999 ft and 1,000 ft or more), and by type (exploratory or development). MMS also provided a list of operators by operator number. EPA linked the name of the operators to wells drilled using the operator number. Names of all operators who had drilled any well in any of the three years were then compiled. The first column of Table 3-2 shows these operators. EPA then used the Security and Exchange Commission's (SEC's) Edgar database, which provides access to various filings by publicly held firms, such as 8Ks and 10Ks. The former documents are useful for determining mergers and acquisitions in more detail, and 10Ks provide annual balance sheet and income statements, as well as listing corporate subsidiaries. The information in the Edgar database as well as data from the OGJ 200 and D&B (see Section Two) was used to identify parent companies or recent changes of ownership (for example, Ocean Energy acquired UMC Petroleum in February 1998). Note that EPA's analysis is based on the status of the industry as of July 1998. Merger and acquisitions continue to occur among this group of firms.

Table 3-2 shows the results of EPA's search for parent companies and recent acquisitions. Generally, EPA characterized a firm at the higher level of organization if it was majority owned by the larger entity (except in a few instances when the subsidiary is large and publicly available information is available for that level of the corporation; e.g., Vastar, which is about 80 percent owned by ARCO). This approach is consistent with the Small Business Administration's (SBA's) definition of affiliation. Small firms that are affiliated (e.g., 51 percent owned) by firms defined as large by SBA's standards (13CFR Part 121) are not considered small for the purposes of regulatory flexibility analysis (see Section Six for more details).

Once EPA accounted for these relationships and transactions, EPA's count of potentially affected firms in the Gulf of Mexico became 96 firms, of which 15 are listed as majors.[6] Twelve firms are identified as foreign owned (not including majors such as Shell Oil, which is affiliated with Royal Dutch/Shell Group), and these firms are included in the analysis. Nonforeign independents total 69 firms, including those not listed in PennWell as majors or independents.[7] EPA currently has not received information on the names of the firms drilling in the area between 3 miles and 3 leagues in Texas, but it is likely that most of the same firms that are drilling in federal waters are also drilling in this area off Texas.

Table 3-3 shows the firms considered affected firms in the Gulf and their relevant financial data. These data include number of employees, assets, liabilities, and revenues, along with several ratios that provide a general indication of financial health. Note that blank lines in Table 3-3 indicate firms that are likely to be privately held and for which no public data are available.

Of these operators drilling in the Gulf, EPA has identified 41 (43 percent) that either meet the Small Business Administration's definition of a small business (which for the oil and gas extraction industry is

[6]PennWell Directory.

[7]*Ibid.*

Table 3-2

Companies Drilling in the Federal Offshore
Gulf of Mexico
Name Changes or Ownership Defined

Company as listed in MMS, 1997	Company listed by Corporate Parent
AEDC (USA) Inc.	AEDC (USA) Inc.
Agip Petroleum Co., Inc.	Agip Petroli (Italy)
Amerada Hess Corp.	Amerada Hess Corp.
American Exploration Co.	S.A. Louis Dreyfus et Cie. (France)
American Explorer	American Explorer
Amoco Production Co.	Amoco Corp.
Anadarko Petroleum Corp.	Anadarko Petroleum Corp.
Apache Corp.	Apache Corp.
Apex Oil & Gas, Inc.	Apex Oil & Gas, Inc.
Ashland Exploration Holdings, Inc.	Statoil (Norway)
ATP Oil & Gas Co.	ATP Oil & Gas Co.
Aviara Energy Co.	HW & T Acquisition Company
Aviva America, Inc.	Aviva Petroleum
Barrett Resources Corp.	Barrett Resources Corp.
Basin Exploration, Inc.	Basin Exploration, Inc.
BHP Petroleum (GOM), Inc.	BHP Petroleum Pty Ltd. (Australia)
Bois d'Arc Operating Corporation	Bois d'Arc Operating Corporation
BP Exploration & Oil, Inc.	British Petroleum Co. plc (U.K.)
British-Borneo Exploration, Inc.	British-Borneo Petroleum Syndicate, plc (U.K.)
BT Operating Co.	BT Operating Co.
Burlington Resources Offshore, Inc.	Burlington Resources Co.
Cairn Energy USA, Inc.	Meridian Resource Corp.
Callon Petroleum Operating Co.	Callon Petroleum Co.
CXY Energy Offshore, Inc.	Canadian Occidental Petroleum Ltd.
Century Offshore Management Corp.	Century Offshore Management Corp.
Chateau Oil and Gas, Inc.	Chateau Oil and Gas, Inc.
Chevron USA Incorporated	Chevron USA Incorporated
Chieftain International (U.S.), Inc.	Chieftain International, Inc. (Canada)
CNG Producing Co.	Consolidated Natural Gas Co.
Coastal Oil & Gas Corp.	The Coastal Corp.
Cockrell Oil Corp.	Cockrell Oil Corp.
Conoco, Inc.	E.I. duPont de Nemours
Davis Petroleum Corp.	Davis Petroleum Corp.
Elf Exploration, Inc.	Elf Aquitaine (France)
Energy Development Corp.	Noble Affiliates
Energy Resources Technology, Inc.	Cal Dive International Inc.

Table 3-2 (continued)

Company as listed in MMS, 1997	Company listed by Corporate Parent
Enron Oil & Gas Co.	Enron Oil & Gas Co.
Enserch Exploration, Inc.	EEX Corporation
EEX Corporation	EEX Corporation
Equitable Resources Energy Co.	Equitable Resources, Inc.
Exxon Corp.	Exxon Corp.
Falcon Offshore Operating Co.	Falcon Offshore Operating Co.
Fina Oil and Chemical Co.	Fina
Flextrend Development Co., LLC	Flextrend Development Co., LLC
Forcenergy GOM, Inc.	Forcenergy, Inc.
Forcenergy, Inc.	Forcenergy, Inc.
Forest Oil Corp.	Forest Oil Corp.
Freeport-McMoRan Resource Partners, LLC	McMoRan Oil & Gas Co.
F-W Oil Interests, Inc.	F-W Oil Interests, Inc.
Global Natural Resources Corp.	Seagull Energy Corp.
Gulfstar Energy, Inc.	Domain Energy Corp.
Hall-Houston Oil Co.	Hall-Houston Oil Co.
Houston Exploration Co.	Houston Exploration Co.
IP Petroleum Co., Inc.	International Paper
Kelley Oil	Kelley Oil
Kerr-McGee Corp.	Kerr-McGee Corp.
Kerr-McGee Oil & Gas Corp.	Kerr-McGee Corp.
King Ranch Energy, Inc.	King Ranch Energy, Inc.
King Ranch Oil and Gas, Inc.	King Ranch Energy, Inc.
Linder Oil Co., A Partnership	Linder Oil Co., A Partnership
Louisiana Land & Exploration	Burlington Resources Corp.
LLOG Exploration Offshore, Inc.	LLOG Exploration Offshore, Inc.
Louis Dreyfus Natural Resources	S.A. Louis Dreyfus et Cie. (France)
Louis Dreyfus Natural Gas Corp.	S.A. Louis Dreyfus et Cie. (France)
Marathon Oil Co.	USX-Marathon Group
Mariner Energy, Inc.	Mariner Energy, Inc.
Matrix Oil & Gas, Inc.	Matrix Oil & Gas, Inc.
McMoRan Oil & Gas Co.	McMoRan Oil & Gas Co.
Mobil Oil Exploration & Production South, Inc.	Mobil Oil Corp.
Mobil Producing Texas & New Mexico, Inc.	Mobil Oil Corp.
Murphy Exploration & Production Co.	Murphy Oil Co.
NCX Company, Inc.	NCX Company, Inc.
Newfield Exploration Co.	Newfield Exploration Co.

Table 3-2 (continued)

Company as listed in MMS, 1997	Company listed by Corporate Parent
Nippon Oil Exploration USA, Ltd.	Nippon Oil (Japan)
Norcen Explorer, Inc.	Union Pacific Resources Group, Inc.
Ocean Energy, Inc.	Ocean Energy, Inc.
OEDC Exploration & Production, L.P.	Offshore Energy Development Corp.
Oryx Energy Co.	Oryx Energy Co.
OXY USA, Inc.	Occidental Petroleum Corp.
Panaco, Inc.	Panaco, Inc.
Pel-Tex Oil Co.	Pel-Tex Oil Co.
Pennzoil Exploration & Production Co.	Pennzoil Co.
Petrobras America, Inc.	Petroleo Brasileiro SA
Petsec Energy, Inc.	Petsec Energy, Inc.
Phillips Petroleum Co.	Phillips Petroleum Co.
Pioneer Natural Resources (GPC), Inc.	Pioneer Natural Resources, Inc.
Pioneer Natural Resources USA, Inc.	Pioneer Natural Resources, Inc.
Pogo Producing Co.	Pogo Producing Co.
Reading & Bates Development Co.	R&B Falcon
Samedan Oil Corp.	Noble Affiliates
Santa Fe Energy Resources, Inc.	Santa Fe Energy Resources, Inc.
Seagull Energy E&P, Inc.	Seagull Energy Corp.
Seneca Resources Corp.	National Fuel Gas Co.
Shell Deepwater Development, Inc.	Shell Oil Co.
Shell Deepwater Production, Inc.	Shell Oil Co.
Shell Offshore, Inc.	Shell Oil Co.
Shell Frontier Oil & Gas, Inc.	Shell Oil Co.
SOCO Offshore, Inc.	Snyder Oil Co.
SONAT Exploration, Inc.	SONAT, Inc.
Sonat Exploration GOM, Inc.	SONAT, Inc.
Statoil Exploration (US), Inc.	Statoil (Norway)
Stone Energy Corp.	Stone Energy Corp.
Tana Oil and Gas Corp.	TRT Holdings, Inc.
Tatham Offshore, Inc.	Deeptech, Inc.
Taylor Energy Co.	Taylor Energy Co.
Texaco Exploration & Production, Inc.	Texaco, Inc.
Total Minatome Corp.	Total (France)
TDC Energy Corp.	TDC Energy Corp.
Transworld Exploration and Production	Transworld Exploration and Production

Table 3-2 (continued)

Company as listed in MMS, 1997	Company listed by Corporate Parent
UMC Petroleum Corp.	Ocean Energy, Inc.
Union Oil Co. of California	Unocal Corp.
Union Pacific Resources Co.	Union Pacific Resources Group, Inc.
Vastar Resources, Inc.	Vastar Resources, Inc.
W & T Offshore, Inc.	W & T Offshore, Inc.
Walter Oil & Gas Corp.	Walter Oil & Gas Corp.

Sources: U.S. Department of the Interior, Minerals Management Service,
TIMS database, Herndon, VA, MMS 97-0007, 1997; SEC's EDGAR Database at http:\\www.sec.gov
U.S. EPA Facility Index System Dun & Bradstreet Detail, 1998.

Table 3-3
Financial Data on Operators in the Gulf of Mexico ($1,000s)

Operator	Size	Type	No. of Employees	Assets	Equity	Revenues	Net Income	Return on Assets	Return on Equity	Profit Margin (net income to total revenue)
AEDC (USA) Inc.	S	Independent	8	na	na	$26,104	na	na	na	na
Agip Petroli (Italy)	L	Foreign	501	$16,948,000	na	7,283,000	$1,257,000	7.4%	na	17.3%
Amerada Hess Corp.	L	Major	9,216	7,934,619	$3,215,699	8,340,046	7,500	0.1%	0.2%	0.1%
American Explorer	S	Independent	18	na	na	1,800	na	na	na	na
Amoco Corp.	L	Major	41,700	32,489,000	16,319,000	36,287,000	2,720,000	8.4%	16.7%	7.5%
Anadarko Petroleum Corp.	L	Major	1,229	2,992,465	1,116,780	675,139	107,318	3.6%	9.6%	15.9%
Apache Corp.	L	Independent	1,287	4,138,633	1,729,177	1,176,273	154,896	3.7%	9.0%	13.2%
Apex Oil & Gas, Inc.	S	Independent	3	na	na	12,000	na	na	na	na
ATP Oil & Gas Co.	S	Independent	12	na	na	160	na	na	na	na
Aviva Petroleum	S	Independent	10	16,445	3,748	9,848	(22,482)	-136.7%	-599.8%	-228.3%
Barrett Resources	S	Independent	207	872,701	412,381	382,600	29,261	3.4%	7.1%	7.6%
Basin Exploration	S	Independent	61	161,959	121,365	24,720	2,456	1.5%	2.0%	9.9%
BHP Petroleum Pty Ltd. (Australia)	L	Foreign	501	29,259,400	na	18,351,500	968,800	3.3%	na	5.3%
Bois d'Arc Operating Corporation	S	Independent	3	na	na	280	na	na	na	na
British Petroleum Co. plc (U.K.)	L	Foreign	15,000	54,576,000	na	71,274,000	4,051,000	7.4%	na	5.7%
British-Borneo Petroleum Syndicate, plc (U.K.)	L	Foreign	501	266,000	na	61,000	16,000	6.0%	na	26.2%
BT Operating Co.	S	Independent	35	na	na	4,819	na	na	na	na
Burlington Resources Corp.	L	Independent	1,819	5,821,000	3,016,000	2,000,000	319,000	5.5%	10.6%	16.0%
Cal Dive International, Inc.	S	Independent	400	125,600	89,369	109,386	14,482	11.5%	16.2%	13.2%
Callon Petroleum Co.	S	Independent	143	190,421	113,701	43,638	8,437	4.4%	7.4%	19.3%
Cal Resources, LLC	S	Independent	na	na	na	na	na	na	na	na
Canadian Occidental Petroleum Ltd.	L	Foreign	501	344,560	na	165,710	28,470	8.3%	na	17.2%
Century Offshore Management Corp.	S	Independent	20	na	na	16,583	na	na	na	na
Chateau Oil and Gas, Inc.	S	Independent	2	na	na	162	na	na	na	na
Chevron USA Incorporated	L	Major	39,362	35,473,000	17,472,000	41,950,000	3,256,000	9.2%	18.6%	7.8%
Chieftain International, Inc. (Canada)	L	Foreign	40	278,550	249,466	72,055	10,160	3.6%	4.1%	14.1%
Cockrell Oil Corp.	S	Independent	45	na	na	4,000	na	na	na	na
Consolidated Natural Gas Co.	L	Independent	7,194	6,313,700	2,358,300	5,710,000	304,400	4.8%	12.9%	5.3%
Davis Petroleum Corp.	S	Independent	14	na	na	2,000	na	na	na	na
Deeptech, Inc.	S	Independent	67	97,130	18,862	16,183	790	0.8%	4.2%	4.9%
Domain Energy Corp.	S	Independent	52	212,549	132,034	52,268	3,163	1.5%	2.4%	6.1%
EEX Corporation *	L	Independent	65	807,789	274,663	314,787	(216,103)	-26.8%	-78.7%	-68.7%
Elf Aquitaine (France)	L	Foreign	501	42,252,000	na	45,087,100	961,000	2.3%	na	2.1%
Enron Oil & Gas Co.	L	Major	7,000	23,422,000	5,618,000	20,273,000	105,000	0.4%	1.9%	0.5%
Equitable Resources, Inc.	L	Independent	1,978	2,411,010	823,520	2,151,015	78,057	3.2%	9.5%	3.6%
Exxon Corp.	L	Major	79,000	96,064,000	43,660,000	137,242,000	8,460,000	8.8%	19.4%	6.2%
E.I. duPont de Nemours	L	Independent	16,000	15,692,000	na	20,579,000	860,000	5.5%	na	4.2%
Falcon Offshore Operating Co.	S	Independent	3	na	na	190	na	na	na	na
Fina	L	Independent	14,675	3,014,674	1,277,112	4,468,547	126,401	4.2%	9.9%	2.8%
Flextrend Development Co., LLC	S	Independent	3	na	na	300	na	na	na	na
Forcenergy, Inc.	S	Independent	275	824,230	214,991	287,539	(134,818)	-16.4%	-62.7%	-46.9%

Table 3-3 (continued)

Operator	Size	Type	No. of Employees	Assets	Equity	Revenues	Net Income	Return on Assets	Return on Equity	Profit Margin (net income to total revenue)
Forest Oil Corp.	S	Independent	177	$647,782	$261,827	$339,641	($9,270)	-1.4%	-3.5%	-2.7%
F-W Oil Interests, Inc.	S	Independent	20	na	na	2,200	na	na	na	na
Hall-Houston Oil Co.	L	Independent	25	na	na	47,206	na	na	na	na
Houston Exploration Co. *	L	Independent	104	491,391	256,187	117,646	23,250	4.7%	9.1%	19.8%
HW & T Acquisition Company	S	Independent	85	na	na	19,100	na	na	na	na
International Paper	L	Independent	82,000	27,753,000	8,793,000	9,896,000	(385,000)	-1.4%	-4.4%	-3.9%
Kelley Oil	S	Independent	81	322,602	(5,621)	76,138	1,951	0.6%	-34.7%	2.6%
Kerr-McGee Corp.	L	Major	3,851	3,096,000	1,440,000	1,711,000	194,000	6.3%	13.5%	11.3%
King Ranch Energy, Inc.	S	Independent	30	na	na	3,500	na	na	na	na
Linder Oil Co., A Partnership	S	Independent	18	na	na	2,000	na	na	na	na
LLOG Exploration Offshore, Inc. *	L	Independent	35	na	na	25,000	na	na	na	na
Mariner Energy, Inc.	S	Independent	48	212,577	57,174	64,050	(20,210)	-9.5%	-35.3%	-31.6%
Matrix Oil & Gas, Inc.	S	Independent	20	na	na	2,200	na	na	na	na
McMoRan Oil & Gas Co. *	L	Independent	16	101,088	90,698	13,552	(10,538)	-10.4%	-11.6%	-77.8%
Meridian Resource Corp.	S	Independent	60	292,558	145,102	58,333	(28,541)	-9.8%	-19.7%	-48.9%
Mobil Oil Corp.	L	Independent	42,700	43,559,000	19,461,000	65,906,000	3,272,000	7.5%	16.8%	5.0%
Murphy Oil Co.	L	Major	1,339	2,238,319	1,079,351	2,137,767	132,406	5.9%	12.3%	6.2%
National Fuel Gas Co.	L	Independent	2,524	2,267,331	913,704	1,269,008	114,688	5.1%	12.6%	9.0%
NCX Company, Inc.	S	Independent	11	na	na	4,452	na	na	na	na
Newfield Exploration Co.	S	Independent	86	553,621	292,048	200,521	40,603	7.3%	13.9%	20.2%
Nippon Oil (Japan)	L	Foreign	501	22,763,400	na	22,020,000	104,100	0.5%	na	0.5%
Noble Affiliates	L	Independent	614	1,875,484	812,989	1,116,623	99,278	5.3%	12.2%	8.9%
Occidental Petroleum Corp.	L	Independent	12,380	15,282,000	4,286,000	8,101,000	668,000	4.4%	15.6%	8.2%
Ocean Energy, Inc.	L	Independent	670	1,707,963	764,671	560,232	37,936	2.2%	6.8%	6.8%
Offshore Energy Development Co. *	L	Independent	18	50,941	41,571	21,563	6,450	12.7%	15.5%	29.9%
Oryx Energy Co.	L	Independent	1,046	2,108,000	157,000	1,197,000	170,000	8.1%	108.3%	14.2%
Panaco, Inc.	S	Independent	40	179,629	55,188	38,586	43	0.0%	0.1%	0.1%
Pel-Tex Oil Co.	S	Independent	25	na	na	2,200	na	na	na	na
Pennzoil Co.	L	Independent	10,036	4,405,887	1,138,539	2,654,304	175,067	4.0%	15.4%	6.6%
Petroleo Brasileiro SA	L	Foreign	501	34,220,700	na	27,944,000	1,353,000	4.0%	na	4.8%
Petsec Energy, Inc.	S	Independent	53	234,104	48,635	125,100	13,100	5.6%	26.9%	10.5%
Phillips Petroleum Co.	L	Major	17,200	13,860,000	4,814,000	15,424,000	959,000	6.9%	19.9%	6.2%
Pioneer Natural Resources, Inc.	L	Independent	1,321	3,946,590	1,548,845	546,029	(890,671)	-22.6%	-57.5%	-163.1%
Pogo Producing Co.	S	Independent	160	676,617	146,106	286,753	37,116	5.5%	25.4%	12.9%
R&B Falcon	L	Independent	5,700	1,034,683	504,614	291,360	48,453	4.7%	9.6%	16.6%
Santa Fe Energy Resources, Inc.	L	Independent	1,209	788,900	454,700	517,200	54,700	6.9%	12.0%	10.6%
Seagull Energy Corp.	L	Major	950	1,411,066	647,204	552,313	49,130	3.5%	7.6%	8.9%
Shell Oil	L	Major	19,400	29,601,000	14,878,000	28,959,000	2,104,000	7.1%	14.1%	7.3%

Table 3-3 (continued)

Operator	Size	Type	No. of Employees	Assets	Equity	Revenues	Net Income	Return on Assets	Return on Equity	Profit Margin (net income to total revenue)
Snyder Oil Co.	S	Independent	327	$546,088	$263,756	$255,728	$32,617	6.0%	12.4%	12.8%
SONAT, Inc.	L	Major	2,110	4,431,514	1,635,420	4,178,305	175,920	4.0%	10.8%	4.2%
Statoil (Norway)	L	Foreign	501	17,851,600	na	17,671,700	610,800	3.4%	na	3.5%
Stone Energy Corp.	S	Independent	90	354,144	156,637	70,987	11,919	3.4%	7.6%	16.8%
S.A. Louis Dreyfus et Cie. (France)	L	Foreign	501	733,613	263,693	189,505	21,102	2.9%	8.0%	11.1%
Taylor Energy Co.	S	Independent	113	na	na	41,584	na	na	na	na
TDC Energy Corp.	S	Independent	20	na	na	8,182	na	na	na	na
Texaco, Inc.	L	Major	28,247	29,600,000	12,766,000	46,667,000	2,664,000	9.0%	20.9%	5.7%
The Coastal Corp.	L	Major	13,200	11,613,100	3,036,500	12,166,900	402,600	3.5%	13.3%	3.3%
Total (France)	L	Foreign	501	25,335,400	na	32,781,000	1,305,700	5.2%	na	4.0%
Transworld Exploration and Production	S	Independent	na	na	na	na	na	na	na	na
TRT Holdings, Inc.	L	Independent	2,200	na	na	200,000	na	na	na	na
Union Pacific Resources Group, Inc.	L	Major	1,500	4,472,000	1,761,000	1,925,000	333,000	7.4%	18.9%	17.3%
Unocal Corp.	L	Independent	8,394	7,530,000	2,314,000	6,064,000	581,000	7.7%	25.1%	9.6%
USX-Marathon Group	L	Independent	20,461	10,565,000	3,618,000	15,754,000	456,000	4.3%	12.6%	2.9%
Vastar Resources, Inc.	L	Independent	1,063	1,924,800	505,500	1,013,700	240,500	12.5%	47.6%	23.7%
W & T Offshore, Inc.	S	Independent	30	na	na	3,700	na	na	na	na
Walter Oil & Gas Corp. *	L	Independent	33	na	na	50,000	na	na	na	na

Source: Oil & Gas Journal. OGJ 200, 1998; Pennwell Petroleum Directory, 1998; SEC's Edgar Database at http:\\www.sec.gov.; U.S. EPA Facility Index System Dun & Bradstreet Detail 1998.

defined as a business entity with 500 or fewer employees or for the oil field service industry as a business entity with $5 million or less in annual revenues) or that cannot be identified as large because their employment or revenue figures are not known. These latter firms might be privately owned, or they do not file with the SEC as an independent firm but their parent company could not be identified. The small and unknown-sized firms are discussed in more detail in Section Six, Regulatory Flexibility Analysis.

Note that operators owned by foreign firms are assumed to be large, even when data on employment could not be found, for the following reasons. First, SBA defines a small business as one "with a place of business in the United States, and which operates primarily in the United States or which makes a significant contribution to the economy" (13 CFR Part 121). EPA assumes that if the U.S. firm is foreign-owned, it would not meet these criteria. Second, the parent corporation most likely would not meet the size criteria. Multinational foreign firms operating in the United States typically operate in many other locations throughout the world and thus would generally require a workforce in excess of 500 persons.

Financially, the potentially affected operators are a healthy group of firms. Table 3-4 presents summary financial statistics for the large and small firms. Financially, the potentially affected operators are a healthy group of firms. Among publicly held firms, median return on assets for the group is 4.3 percent, median return on equity is 10.2 percent, and median profit margin (net income/revenues) is 6.6 percent, according to 1997 financial data. Among these publicly held firms, 60 out of 69 firms, or 87 percent, reported positive net income for 1997.

3.3.1.4 Estimates of Drilling Activity

Table 3-5 presents data from MMS on drilling activity in 1995, 1996, and 1997 by type of drilling and by depth. As the table shows, most wells drilled in the Gulf of Mexico Federal OCS are development wells drilled in less than 1,000 feet of water. Exploratory drilling in waters less than 1,000 ft. deep also makes up a major portion of wells drilled annually. The numbers of wells drilled has been rising over the 3-year period, and an average of 1,119 wells were drilled in the Federal OCS during this timeframe.

Data on wells drilled in the state waters off Texas in the 3 miles to 3 leagues area are not included in the MMS count, but the Railroad Commission of Texas (RRC) indicated that 10 wells were drilled in 1996, 5

Table 3-4

Minimum, Median, and Maximum Financial Data for Large and Small Firms ($1,000s)

	No. of Employees	Assets	Equity	Revenues	Net Income	Return on Assets	Return on Equity	Profit Margin (net income to total revenue)
				Small firms				
Minimum	2	$16,445	($5,621)	$160	($134,818)	-136.7%	-599.8%	-228.3%
Median	37.5	$263,331	$126,700	$16,383	$2,810	1.5%	3.3%	6.8%
Maximum	400	$872,701	$412,381	$382,600	$40,603	11.5%	26.9%	20.2%
				Large firms				
Minimum	16	$50,941	$41,571	$13,552	($890,671)	-26.8%	-78.7%	-163.1%
Median *	1,339	$4,405,887	$812,989	$2,151,015	$154,896	4.4%	9.5%	6.2%
Maximum	82,000	$96,064,000	$43,660,000	$137,242,000	$8,460,000	12.7%	108.3%	29.9%
				All firms				
Minimum	2	$16,445	($5,621)	$160	($890,671)	-136.7%	-599.8%	-228.3%
Median *	400	$2,267,331	$705,938	$286,753	$99,278	4.3%	10.2%	6.6%
Maximum	82,000	$96,064,000	$43,660,000	$137,242,000	$8,460,000	12.7%	108.3%	29.9%

Source: Oil & Gas Journal. OGJ 200, 1998; Pennwell Petroleum Directory, 1998; SEC's Edgar Database at http:\\www.sec.gov.; U.S. EPA Facility Index System Dun & Bradstreet Detail, 1998.

* Used hypothetical number (501) for employees for larger firms when number of employees was not available.

Table 3-5

Number of Wells Drilled in the Gulf of Mexico OCS and Texas Where Controlled Discharge of Drilling Fluids and Cuttings Is Allowed

Year	Shallow Water Wells (<1,000 feet)		Deep Water Wells (>1,000 feet)		Total Wells
	Development	Exploratory	Development	Exploratory	
1995	577	314	32	52	975
1996	617	348	42	73	1,080
1997	726	403	69	104	1,302
Annual Average OCS	640	355	48	76	1,119
Estimated Wells Drilled 3 Miles to 3 Leagues Offshore TX	5	3	0	0	8
Total Annual Estimate	645	358	48	76	1,127

Source: MMS TIMS data and personal communication with RRC (James Covington, EPA, and Donna Burks, RRC, Sept. 1, 1998).

in 1997, and 9 so far in 1998 in the Texas offshore region (which includes everything offshore, including less than 3 miles from shore) or an average of 8 wells per year (communication between James Covington, EPA, and Donna Burks, RRC, September 1, 1998).[8] When this number of wells is added to the OCS numbers, EPA projects that a total of 1,127 wells on average are drilled per year in the Gulf. EPA also estimates that 10 percent, or 113 wells, are drilled currently with SBFs and 10 percent, or 112 wells, are drilled with OBFs. EPA further estimates that no OBFs are used in deep water drilling, and of the 112 OBF wells estimated to be drilled annually in shallow water, 20 percent, or 23 wells, would convert to using SBFs if discharge of SBF-cuttings was allowed.[9] The remaining 902 wells that are estimated to be drilled annually in the Gulf of Mexico are assumed to be drilled exclusively using WBFs and thus would not incur costs or realize savings under this proposed rule.

3.3.2 Offshore California

Most production activity in the Offshore California region is occurring in an area 3 to 10 miles from shore off of Santa Barbara and Long Beach, California.

3.3.2.1 Current Practice

Currently, no wells use SBF or discharge SBF-cuttings in the California OCS region. As noted in Section Two, the General Permit expired, and no wells have been drilled with an individual permit since 1993. Newer SBFs are not believed to be used in California at this time, although oil-based fluids are used.[10]

[8]These are not NPDES CWA permits, but permits issued by the state of Texas.

[9]SBF Development Document.

[10]*Ibid*.

3.3.2.2 Platforms in the Region

Currently 23 platforms operate on the California OCS, of which two are processing platforms only. All are located greater than 3 miles from shore, with Platform Grace located the farthest from shore at 10.5 miles. Most of the platforms are located in the Santa Barbara Channel, with a few located in the Santa Maria Basin, and several offshore Long Beach, CA. The largest platform, Platform Gilda, has 96 well slots. The smallest platform, Platform Gina, has 15 well slots.[11]

3.3.2.3 Operators

There are five operators currently actively drilling (1995-1997) in the California Offshore OCS region.[12] These operators are Chevron; Aera Energy, LLC; Exxon; Torch Energy Advisors (through their subsidiary Torch Operating Co.); and Nuevo Energy Co. (which has an affiliation with Torch, who operates the platforms). Detailed employment and financial information on Torch Energy Advisors (other than employment) and Aera Energy is not available. Table 3-6 presents the available data on the five operators. As the table shows, Chevron, Exxon, and Torch are large firms, and Nuevo by affiliation with Torch is also considered large (Nuevo and Torch have the same headquarters, and Nuevo lists Torch's employment along with their own in their 10K form, among other evidence of affiliation), while Aera Energy could not be found in the SEC Edgar database and is thus assumed small for lack of data. Among the remaining firms, median return on assets is 7.5 percent, median return on equity is 16.7 percent, and median profit margin is 5.2 percent. No operators reported negative net income among publicly held firms. Thus, the California firms, like the Gulf firms, generally appear to be financially healthy.

[11]http://www.mms.gov/pacific/explorat/plfintro.html

[12]MMS, TIMS database.

Table 3-6
Financial Information on Operators in the California Offshore Region ($1,000s)

Operator	No. of Employees	Assets	Equity	Revenues	Net Income	Return on Assets	Return on Equity	Profit Margin (net income to total revenue)
Chevron USA Incorporated	39,362	$35,473,000	$17,472,000	$41,950,000	$3,256,000	9.2%	18.6%	7.8%
Aera Energy, LLC								
Texaco, Inc.	28,247	29,600,000	12,766,000	46,667,000	2,664,000	9.0%	20.9%	5.7%
Torch Energy Advisors	729							
Nuevo Energy	59	904,773	388,867	358,193	18,751	2.1%	4.8%	5.2%
Medians	14,488	$29,600,000	$12,766,000	$41,950,000	$2,664,000	9.0%	18.6%	5.7%

Source: Oil & Gas Journal. OGJ 200, 1998; Pennwell Petroleum Directory, 1998; SEC's Edgar Database at http:\\www.sec.gov.; U.S. EPA Facility Index System Dun & Bradstreet Detail, 1998.

3.3.2.4 Drilling Activity

In offshore California waters, no exploratory wells were drilled in the three years 1995-1997.[13] In 1995, 15 development wells were drilled in water depths greater than 1,000 ft and 4 were drilled in water depths of 999 ft or less (19 wells total). In 1996, the number of wells drilled grew to 16 wells in greater than 1,000 ft of water and 15 wells in 999 ft or less (31 wells total). In 1997 the number of wells drilled dropped slightly, with 14 wells drilled in greater than 1,000 ft of water and 14 wells in 999 ft or less (28 wells total). Thus EPA estimates that an average of 26 development wells and no exploratory wells are drilled in the California OCS each year. EPA further estimates that 12 wells are drilled using OBFs each year (none are drilled using SBFs) and that these wells would be drilled with SBFs if the SBF Guidelines allow discharge of SBFs.[14]

3.3.3 Cook Inlet, Alaska

Cook Inlet, Alaska, is divided into two regions, Upper Cook Inlet, which is in state waters and is governed by the Coastal Oil and Gas effluent guidelines and Lower Cook Inlet, which is considered Federal OCS waters and is governed by the Offshore Oil and Gas Effluent Guidelines. Lower Cook Inlet is discussed as part of the Alaska Offshore region in Section 3.3.4 below. This section refers to Upper Cook Inlet only. Figure 3-2 shows the configuration of operations in Cook Inlet relative to the Kenai Peninsula and Anchorage, with the dividing line between the Coastal and Offshore Regions shown.

3.3.3.1 Current Practice

Most drilling in Cook Inlet takes place at the platforms. Exploratory drilling, such as that undertaken in the Sunfish Field a few years ago, generally is conducted from jackup rigs, which are barge-mounted rigs with extendable legs that are retracted during transport. At the drill site, the legs are extended to the floor of the waterbody, gradually lifting the barge hull above the water.

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[13] MMS, TIMS Database.

[14] SBF Development Document.

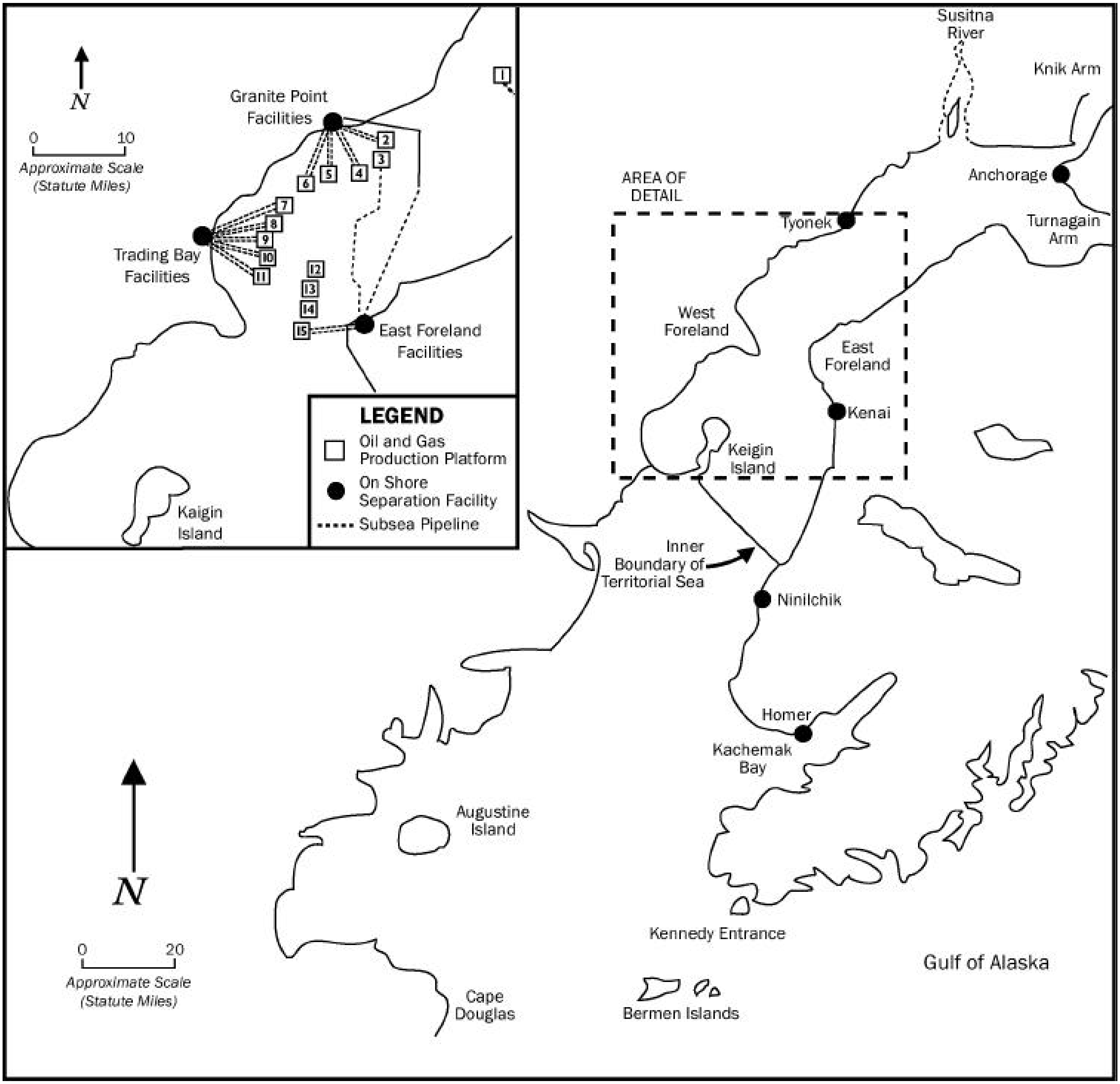

Figure 3-2. Map of Cook Inlet region.

Currently no operators are believed to be using SBFs in Cook Inlet.[15] The General Permit for Cook Inlet is expected not to allow discharge of SBF-cuttings, but the permit will be reopened when effluent guidelines or guidance are provided to address discharge of SBFs. At least one operator has requested to discharge SBF-cuttings.[16]

3.3.3.2 Platforms

Fifteen platforms are located in Cook Inlet, Alaska (see Figure 3-2). However, at least two of these platforms are currently shut in. An additional platform might also be shut in, but this information was not confirmed at this time.[17] Table 3-7 presents data on number of wells, production, and operator for each of the active and nonactive platforms as of 1995. As shown, there are 197 oil wells and 27 gas wells in Cook Inlet, with an annual production of 13.7 million barrels of oil and 140,525 million Mcf (thousand cubic feet) of marketable gas in 1995.[18] A potential area of development in Cook Inlet is the Sunfish field, which is located in North Upper Cook Inlet. At this time the Sunfish Field development is underway at the Tyonek platform, and no new platforms are planned. The last platform constructed in Cook Inlet was built in the late 1980s.[19]

3.3.3.3 Operators

Three operators are currently active in Cook Inlet: Unocal, Phillips, and Shell (as Shell Western).[20] All three are major integrated oil firms, and all three also operate in the Gulf of Mexico. ARCO also has

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[15]API, 1998. Responses to Technical Questions for Oil and Gas Exploration and Production Industry Representatives. Email from Mike Parker, Exxon, to Joe Daly, U.S. EPA, August 7, 1998.

[16]John Veil, 1998. "Data Summary of Offshore Drilling Waste Disposal Practices." November, 1998.

[17] Coastal EIA.

[18] *Ibid.*

[19]Coastal EIA.

[20]*Ibid.*

TABLE 3-7

PLATFORMS, OPERATORS, AND WELLS IN COOK INLET

Platform	Operator	No. of Active Oil Wells	No. of Active Gas Wells	Oil Production (barrels per day)	Gas Production (Mcf/day)	Discharge Location
King Salmon	Unocal	19	1	3,864	Plat. use	Trading Bay
Monopod	Unocal	22	0	1,981	Plat. use	Trading Bay
Grayling	Unocal	23	1	5,207	Plat. use	Trading Bay
Granite Point	Unocal	11	0	6,086	Plat. use	Granite Point
Dillon	Unocal	10	0	841	0	Platform
Bruce	Unocal	13	0	865	Plat. use	Platform
Anna	Unocal	23	0	3,117	Plat. use	Platform
Baker	Unocal	14	2	1,301	Plat. use	Platform
Dolly Varden	Unocal	24	1	4,983	Plat. use	Trading Bay
Spark*	Unocal	0*	0*	0	0	Platform
Steelhead	Unocal	4	9	4,184	165,000	Trading Bay
Spurr*	Unocal	0*	0*	0	0	Granite Point
SWEPI “A”	Shell Western	17	0	3,200	Plat. use	E. Foreland
SWEPI “C”	Shell Western	17	0	1,800	Plat. use	E. Foreland
Tyonek “A”	Phillips	0	13	0	22,000	Platform

*Spark and Spurr are considered completely nonactive in this EA. One additional platform might also have shut in since these data were compiled.

Source: U.S. EPA. 1996. *Development Document for Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category*.

been involved in exploratory drilling in the Sunfish Field, but Alaska state data indicate that Phillips has bought out ARCO's interests in this field [21] and is pursuing drilling from its Tyonek platform.[22] Unocal is the largest producer of oil in the Upper Cook Inlet region. This operator owned 12 of the 15 platforms (9 believed to be currently active) and produced 86 percent of the oil in the Inlet in 1995. Phillips is the major producer of gas, with its one Tyonek platform, producing 57 percent of the region's marketable gas in 1995. Shell, through its subsidiary Shell Western operates SWEPI A and B platforms.[23] Table 3-8 presents relevant financial information on these operators. Median return on assets for this group is 7.1 percent, median return on equity is 14.1 percent, and median profit margin is 7.3 percent. No firm reported negative net income in 1997. Again, these firms appear financially healthy.

3.3.3.4 Estimates of Drilling Activity in the Region

Over the past three years (1995-1997) operators have drilled seven wells on average—five development and two exploration wells.[24] Based on discussions with industry (see Coastal EIA), EPA estimates that no off-platform drilling will be undertaken in Cook Inlet. Thus for the purpose of this report, EPA assumes seven wells per year will be drilled in Cook Inlet, and all are considered existing sources. EPA further assumes that one well is drilled annually with OBFs and that SBFs would replace OBFs if the SBF Guidelines allow discharge of SBF-cuttings.[25]

3.3.4 Offshore Alaska

The offshore Alaska region comprises several areas, which are located both in state waters and in federal OCS areas. The most active area for exploration has been the Beaufort Sea, the northernmost

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[21]http:www.dnr.state.ak.us\oil\data\wells.htm, page 14.

[22]Coastal EIA.

[23]*Ibid.*

[24]SBF Development Document.

[25]*Ibid.*

Table 3-8
Financial Data on Operators in Cook Inlet ($1,000s)

Operator	No. of Employees	Assets	Equity	Revenues	Net Income	Return on Assets	Return on Equity	Profit Margin (net income to total revenue)
Phillips Petroleum Co.	17,200	13,860,000	15,424,000	15,424,000	959,000	6.9%	6.2%	6.2%
Shell Oil	19,400	29,601,000	14,878,000	28,959,000	2,104,000	7.1%	14.1%	7.3%
Unocal Corp.	8,394	7,530,000	2,314,000	6,064,000	581,000	7.7%	25.1%	9.6%
Medians	17,200	$13,860,000	$14,878,000	$15,424,000	$959,000	7.1%	14.1%	7.3%

Source: Oil & Gas Journal. OGJ 200, 1998; Pennwell Petroleum Directory, 1998; SEC's Edgar Database at http:\\www.sec.gov.; U.S. EPA Facility Index System Dun & Bradstreet Detail, 1998.

offshore area on the Alaska coastline. Other areas where some exploration has occurred include Chukchi Sea to the northwest, Norton Sound to the West, Navarin Basin to the west, St. George Basin to the southwest, lower Cook Inlet to the south, and Gulf of Alaska along the Alaska panhandle (see Figure 3-3). The only commercial production of any note is occurring in the Beaufort Sea region.[26]

3.3.4.1 Current Practice

To EPA's knowledge, no operations are discharging any drilling fluids, including WBFs, in the offshore Alaska region. No discharge is occurring in state waters due to state law requiring operators to meet zero discharge. In the federal offshore region, the Offshore Guidelines do not specifically prohibit discharge of SBF-cuttings, but all operators historically have injected their drilling wastes. No commercial production has occurred in any federal offshore area.[27] Some promising finds have been made in federal offshore water in recent years, but development may be several years off. These fields include the Liberty (Tern Island) Field and the Northstar Field, both in the Beaufort Sea. Currently a draft Environmental Impact Statement (EIS) is being prepared for the Liberty Field (DNR). The Northstar Field has encountered significant resistance to development.[28] The operator (BP) halted construction for over a year as a result of a lawsuit (which was resolved in May 1998).[29] The operator has just begun the task of responding to comments on its draft environmental impact statement, which must be finalized before production operation can start.[30]

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[26]http://www.mms.gov/alaska/re/96-0033/10.htm and State of Alaska, Alaska Oil and Gas Conservation Commission, 1996. *1996 Annual Report*.

[27]http://www.mms.gov/alaska/re/96-0033/10.htm

[28]"Stop BP's Northstar Project," http://www.greenpeace.org/~climate/arctic/act.html

[29]"BP Puts Project On Hold," http://www.adn.com/TOPSTORY/T9702141.HTM; "Baxley v. Alaska DNR (5/15/98)," http://www.touchngo.com/sp/html sp-4988.htm

[30]http://www.mms.gov/alaska/cproject/northstar/northstar.htm

Sale Areas Offshore Alaska Where Exploratory Drilling Has Occurred

Area	Wells Drilled
Beaufort Sea	30
Chukchi Sea	4
Norton Sound	6
Navarin Basin	8
St. George Basin	10
Cook Inlet	13
Gulf of Alaska	12
Total	**83**

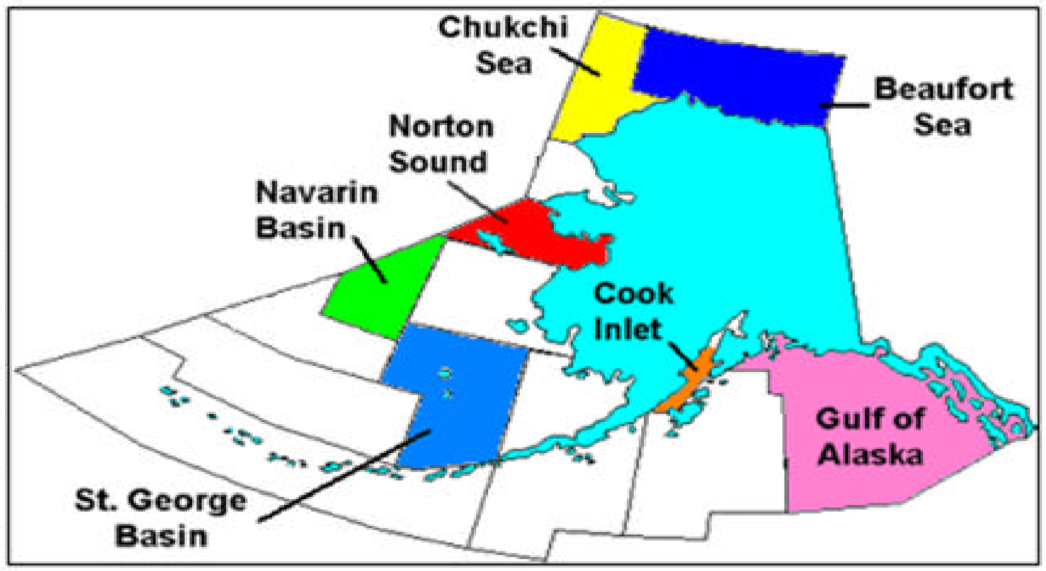

Figure 3-3. Map of Alaska offshore exploration areas showing total number of wells drilled to date (1998).

Source: http://www.mms.gov/alaska/fo/history/salearea.htm

3.3.4.2 Estimates of Drilling Activity in the Area

Historically, drilling in the offshore Alaska regions has been typically exploratory (with the primary exception of the Endicott Field development in the Beaufort Sea). Since the beginning of exploration in the Alaska Offshore region, 83 exploratory wells have been drilled in Federal Offshore waters (see Figure 3-3), primarily in the Beaufort Sea, where nearly 40 percent of all exploratory wells in the Alaska federal offshore region have been drilled. Exploratory well drilling in federal waters has slacked off significantly in recent years (see Figure 3-4). From a peak of about 20 wells per year in 1985, no wells were drilled in 1994, 1995, and 1996, and two were drilled in 1997 for an average of less than one well drilled per year. EPA therefore assumes that no significant drilling activity will be occurring in the Federal Offshore regions of Alaska. Offshore Alaska, therefore, is within the scope of the regulation but is not expected to be associated with costs or savings as a result of the proposed effluent guidelines, either in state offshore waters (because of state law) or in federal waters (due to historic practice and lack of activity). Wells drilled in this region are not included in the count of potentially affected wells.

3.4 SUMMARY OF WELL COUNTS AND OPERATOR COUNTS

EPA estimates that a total of 1,160 wells, on average, are drilled each year in the regions potentially affected by the SBF Guidelines (see Table 3-9). Of these, EPA estimates that 113 wells are drilled, on average, each year using SBFs in the Gulf (none in California and none in Cook Inlet). EPA further estimates that a total of 125 wells are drilled annually using OBFs, of which 112 are drilled in the Gulf, 12 in California, and 1 in Cook Inlet. EPA assumes that a total of 23 wells in shallow water Gulf locations, 12 wells in California, and 1 well in Alaska, for a total of 36 wells annually, would switch from OBFs to SBFs if the SBF Guidelines allow discharge.[31]

The number of operators currently drilling wells in the regions total 99 firms, of which 42 (42 percent) are estimated to be small. These operators include the 96 operators in the Gulf of Mexico, and the 3 additional operators in the Pacific (two Pacific operators also drill in the Gulf). All Cook Inlet operators also

[31]SBF Development Document.

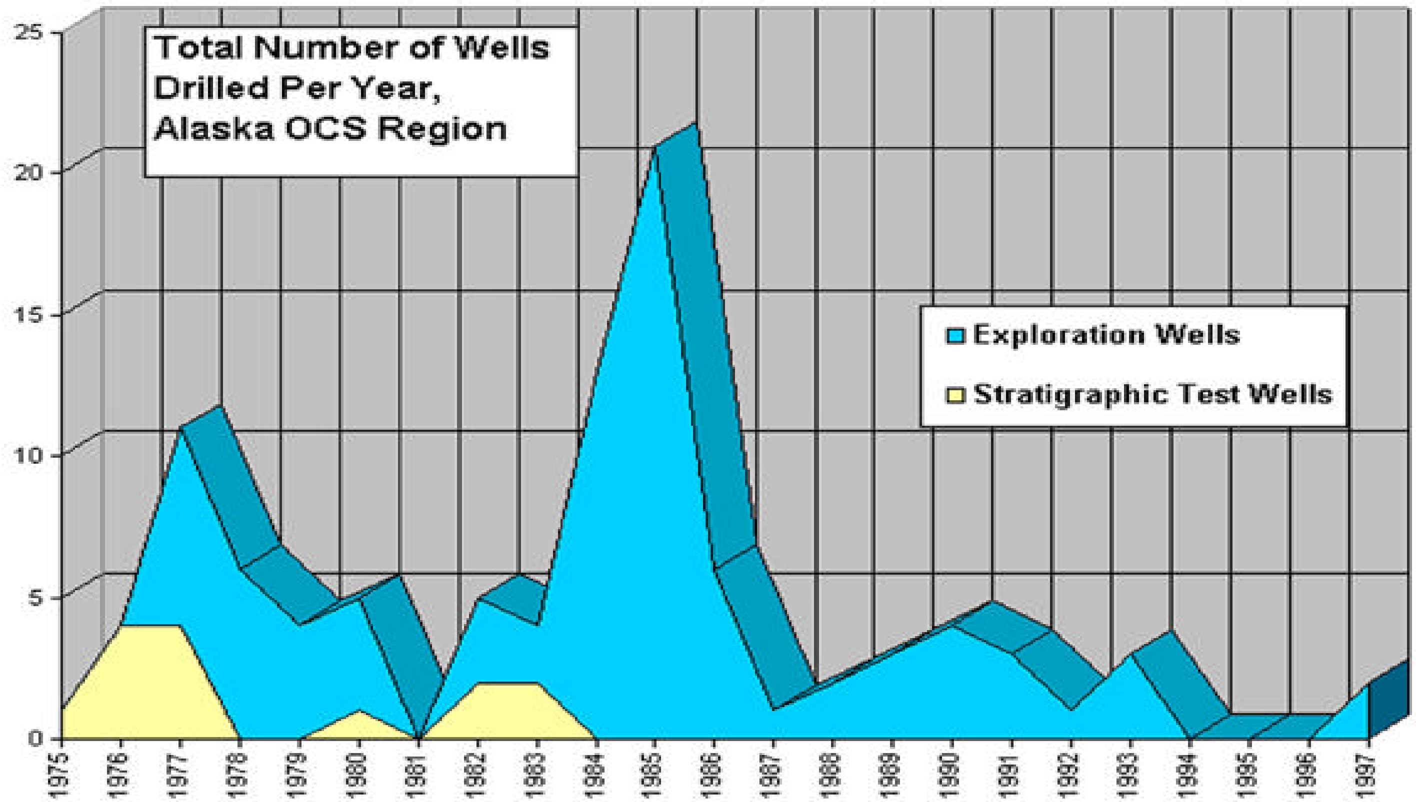

Figure 3-4. Total number of wells drilled per year, Alaska OCS region.

Source: http://www.mms.gov/alaska/fo/history/allwellc.htm

Table 3-9

Total Number of Wells Drilled in All Affected Regions

	Shallow Water Wells (<1,000 ft)		**Deep Water Wells (>1,000 ft)**		**Total**
	Developmen t	**Exploratory**	**Developmen t**	**Exploratory**	
Gulf of Mexico OCS (including Texas state waters)*	645	358	48	76	1,127
California OCS	11	0	15	0	26
Alaska Cook Inlet Coastal	5	2	0	0	7
Total, All Regions	661	360	63	76	1,160

Source: SBF Develoment Document.

*Texas wells were apportioned to type and depth using the same proportions as those found among Gulf OCS wells.

drill in the Gulf. These counts will be used in later sections of this report as baseline data for the economic analysis.

SECTION FOUR

REGULATORY OPTIONS AND AGGREGATE COSTS OF THE EFFLUENT GUIDELINES

This section presents the regulatory options considered for offshore drilling operations and the total costs of compliance for the SBF Guidelines. Only wells that are drilled with SBFs or those drilled with OBFs that are assumed to convert to SBFs are determined to have costs or realize savings under the regulation.

4.1 REGULATORY OPTIONS

EPA considered two options for the proposed rule: one is a discharge option allowing SBF cuttings discharge (discharge of SBF not associated with cuttings would not be allowed and is not current practice) and a zero discharge option. These options are considered for both existing sources under Best Available Treatment Economically Achievable (BAT) and new sources, under New Source Performance Standards (NSPS).[1] There is also an implicit no-action option under which zero costs are incurred. See Table 4-1 for a description of these options and a shortened name that will be used in the EA.

The discharge option involves the discharge of SBF cuttings after treatment by a solids control device that achieves an average of 7 percent retention of the base fluid on cuttings (see Section 3.2.4.2). The discharge costs and cost savings include costs for: the add-on solids control device, retrofit of the drilling platform to accommodate the device, the value of the SBF retained on the cuttings (which generates the overall cost savings), and monitoring analyses.

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[1]Best Practical Control Technology (BPT) and Best Conventional Pollutant control Technology (BCT) are associated with no incremental costs so are not discussed in this report. Additionally, there are no known indirect dischargers so Pretreatment Standards for Existing Sources (PSES) and Pretreatment Standards for New Sources (PSNS) also are not discussed.

Table 4-1

Summary of Regulatory Options

Regulation	Short Option Description	Option
Option 1	Discharge	■ SBF-cuttings alone may be discharged. ■ Control of base fluids acceptable for discharge in terms of polynuclear aromatic hydrocarbon content, sediment toxicity, and biodegradation rate. ■ Control of SBF retained on cuttings. ■ New monitoring methods for formation oil contamination. ■ Maintenance of current stock barite limitations for cadmium and mercury. ■ Maintenance of static sheen test.
Option 2	Zero Discharge*	■ Zero discharge of SBF drilling fluids and SBF-cuttings.

* Current zero discharge requirements are zero discharge within 3 miles of shore, except in Offshore Alaska and Coastal Cook Inlet Alaska, which allow discharge per limitations.

The zero discharge option has the potential to generate additional costs, but only for wells in the Gulf of Mexico because the Alaska and California wells are at zero discharge in the baseline. The SBF wells in the Gulf of Mexico are discharging, but at an 11% retention of base fluid on cuttings in the baseline, while OBF-drilled wells are at zero discharge. Thus under the zero discharge option only wells drilled with SBFs in the Gulf are affected. The zero discharge option is associated with costs to haul cuttings to shore with land treatment/disposal or to inject the wastes at or near the site of the drilling operation. EPA's preferred option for this proposal, for both BAT and NSPS, is the discharge option.

4.2 TOTAL COMPLIANCE COSTS

As Table 4-2 shows, total compliance costs for the preferred discharge option are actually cost savings (due to the value of the drilling fluids captured for recycling). These cost savings amount to $6.6 million per year for BAT and $0.6 million per year for NSPS for a total cost savings of $7.2 million per year. Under the zero discharge option, costs would be $7.0 million per year under BAT and $1.6 million per year under NSPS for a total of $8.6 million per year.

Table 4-2

Incremental Costs/Cost Savings of Compliance with the SBF Guidelines (thousands, 1997 dollars)

Option	BAT				NSPS				Total Costs/ Cost Savings
	Gulf	CA	AK	Total	Gulf	CA	AK	Total	
Discharge	($5,985)	($509)	($92)	($6,586)	($570)	$0	$0	($570)	($7,156)
Zero Discharge	$6,964	$0	$0	$6,964	$1,594	$0	$0	$1,594	$8,558

Source: SBF Development Document

SECTION FIVE

ECONOMIC IMPACTS OF THE PROPOSED RULEMAKING

Under the preferred discharge option, the proposed effluent guidelines would provide a cost savings to industry. This cost savings would be experienced by wells currently discharging cuttings contaminated with SBFs and other water non-dispersible fluids and by wells currently land-disposing or injecting OBF cuttings that convert to SBF. As discussed in Section Four, the cost savings for SBF dischargers result from the use of improved solids control equipment and the subsequent ability of operators to recycle additional volumes of expensive SBFs, which more than offsets the costs of the improved solids control equipment. For wells that would have been drilled with OBF, the cost savings result from switching to SBF and discharging, thus avoiding higher zero discharge disposal costs. Operations using WBFs would not be affected by the SBF Guidelines.

For each regulatory option, EPA estimated the change in the cost of drilling wells, impacts on operating a production unit (typically a platform), impacts on firms, both large and small (impacts on small firms specifically are discussed in Section Six), employment impacts in the oil and gas industry, and impacts on related industries (e.g., drilling contractors, drilling fluid companies, mud cleaning equipment rental firms, transport and disposal firms, etc.) as a result of the proposed BAT and NSPS requirements. The results of these analyses are summarized below in Section 5.1 (for existing sources) and Section 5.2 (for new sources).

5.1 IMPACTS ON EXISTING SOURCES

5.1.1 Impacts on Costs of Drilling Wells

As discussed in Section Four, under the discharge option, EPA projects aggregate costs savings for wells using SBFs and for wells using OBFs that convert to SBFs. Table 5-1 shows the four model well types defined in Section Four and provides estimates of potential costs or cost savings as a percentage of total costs to drill a well associated with various subsets of these well types. Costs and cost savings vary

TABLE 5-1

COST SAVINGS OF THE BAT DISCHARGE OPTION AS A PERCENTAGE OF BASELINE DRILLING COSTS ($1997)

Type of Well	Number of Wells	Incremental Cost of Discharge Option (per well)	Incremental Cost of Zero Discharge Option (per well)	Total Baseline Cost of Drilling Well ($MM)	Cost/Cost Savings as a Percentage of Total Drilling Cost	
					Discharge Option	Zero Discharge Option
GULF OF MEXICO						
Deep Water SBF Developmental (haul)	14	($29,302)	$95,507	$2.9	-1.0%	3.3%
Deep Water SBF Developmental (inject)	4	($29,302)	$57,205	$2.9	-1.0%	2.0%
Shallow Water SBF Developmental (haul)	10	($17,502)	$19,113	$2.9	-0.6%	0.7%
Shallow Water SBF Developmental (inject)	2	($17,502)	($10,555)*	$2.9	-0.6%	-0.4%
Shallow Water OBF Developmental (haul)	12	($36,615)	$0	$2.9	-1.3%	0.0%
Shallow Water OBF Developmental (inject)	3	($6,947)	$0	$2.9	-0.2%	0.0%
Deep Water SBF Exploratory (haul)	46	($70,502)	$79,813	$3.9	-1.8%	2.0%
Deep Water SBF Exploratory (inject)	11	($70,502)	$127,825	$3.9	-1.8%	3.3%
Shallow Water SBF Exploratory (haul)	6	($41,502)	$28,315	$4.9	-0.8%	0.6%
Shallow Water SBF Exploratory (inject)	1	($41,502)	($21,950)*	$4.9	-0.8%	-0.4%

TABLE 5-1 (continued)

Type of Well	Number of Wells	Incremental Cost of Discharge Option (per well)	Incremental Cost of Zero Discharge Option (per well)	Total Baseline Cost of Drilling Well ($MM)	Cost/Cost Savings as a Percentage of Total Drilling Cost	
					Discharge Option	Zero Discharge Option
Shallow Water OBF Exploratory (haul)	6	($69,817)	$0	$4.9	-1.4%	0.0%
Shallow Water OBF Exploratory (inject)	2	($19,552)	$0	$4.9	-0.4%	0.0%
CALIFORNIA						
Deep Water OBF Developmental	11	($43,658)	$0	$1.6	-2.7%	0.0%
Shallow Water OBF Developmental	1	($28,899)	$0	$1.6	-1.8%	0.0%
ALASKA						
Shallow Water OBF Developmental	1	($92,266)	$0	$2.8	-3.3%	0.0%

Note: negative value or values in parentheses represent a cost savings.

*See SBF Development Document for explanation of cost savings.

Source: Development Document, Appendix A, and the Joint Association Survey.

depending on the region, the type of fluid currently used, and the operator's choice of zero discharge (under the zero discharge option only)–hauling to shore for disposal or injecting the waste (the latter, less expensive option is not technically feasible at all locations). See the SBF Development Document for detailed information on how the numbers of wells were estimated in each category and Appendix A of this report for how the aggregate costs of each well type were disaggregated to estimate a per-well cost.

Table 5-1 shows that most cost savings under the preferred discharge option would be about 1 to 2 percent of total well drilling costs, with a few exceptions. Deep water development wells using OBFs in California would realize cost savings of as much as 2.7 percent of total costs, and the estimated one Alaska well using OBFs in Cook Inlet would realize a cost savings of 3.3 percent of total well drilling costs. In general, these cost savings are not a large portion of costs to drill and therefore should have no to at most a small incentive on well drilling activity.

Under zero discharge, wells using OBFs would incur no incremental costs of compliance since they already meet zero discharge requirements. Among those currently using SBFs, the median percentage of compliance costs to the total cost of drilling wells is 2.0 percent.

5.1.2 Impacts on Platforms and Production

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

Under EPA's zero discharge option, EPA investigated potential impacts based on previous work performed as part of the offshore oil and gas effluent guidelines rulemaking.[1] The costs of such an option, compared to the baseline costs of drilling wells in the Gulf are presented in Table 5-1. EPA previously

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[1]Offshore EIA.

investigated the impact of zero discharge of all drilling fluids and cuttings on platform-based production operations in the offshore regions of the Gulf and found, at that time, "none of the options considered ... [including zero discharge] for drilling fluids and drill cuttings has an adverse impact on hydrocarbon production." (58 FR 12454-12152). Furthermore, as stated in the Offshore EIA, EPA estimated no change in the total production for any project (by platform type and location) analyzed under any regulatory scenario for drilling waste (including zero discharge). EPA believes a similar impact would occur today.

5.1.3 Impacts on Firms

EPA estimated impacts on firms by assessing the costs and cost savings of the regulatory options as a percentage of revenues. The cost savings associated with the preferred discharge option would have from no impact to a very small impact on the investment decisions by the majority of the companies affected by the proposed rule. EPA assumes that the likeliest users of SBF in shallow water locations are the same operators who use SBF in deep water operations. Only a few operators drill where SBF is primarily used, in the Gulf deepwater locations. A total of 18 firms (19 percent of the 98 firms considered potentially affected) drilled in deepwater locations over the period 1995-1997. As Table 5-2 shows, total cost savings among these firms would probably be at most nearly 0.3 percent of revenues.[2] EPA has assumed for this calculation that these 18 firms' deep water wells would be drilled using SBFs at the frequency of use for all deep water wells (75 percent of wells are estimated to be drilled currently using SBF in deep water locations).[3] To estimate the number of SBF wells drilled in shallow water by each of the 18 firms, EPA distributed the shallow water SBF wells according to the ratio of wells drilled by each firm in shallow water to the total number of wells drilled in shallow water by these 18 firms. For example, Shell Oil is currently estimated to drill an average of 57 shallow water development wells per year (see Appendix B). This is 21 percent of the 271 development wells drilled in shallow water by the 18 firms considered to be likeliest users of SBFs (see Appendix B). As noted earlier, EPA estimated that 12 development wells are drilled annually using SBFs in shallow water. Shell Oil is assumed, therefore, to drill

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[2]Note that cost savings to firms who might switch from OBFs to SBFs are not estimated because EPA cannot determine which firms might switch.

[3]Development Document.

Table 5-2
Estimated Cost or Cost Savings of the Discharge Option and Zero Discharge Option as a Percentage of Revenue, By Potentially Affected Firm

Firms	Total Cost of the Discharge Option	Total Cost of the Zero Discharge Option	Firm Revenues (In Milliions)	Revenues as % of Discharge Option Costs	Revenues as % of Zero Discharge Option Costs
E.I. duPont de Nemours	($85,825)	$150,174	$20,579	-0.0004%	0.0007%
Amerada Hess Corp.	($228,399)	$317,700	$8,340	-0.0027%	0.0038%
Chevron USA Incorporated	($320,706)	$624,897	$4,195	-0.0008%	0.0015%
Occidental Petroleum Corp.	($143,179)	$236,733	$1,197	-0.0120%	0.0198%
Amoco Corp.	($221,011)	$322,062	$36,287	-0.0006%	0.0009%
Union Pacific Resources Group, Inc.	($88,675)	$97,977	$1,925	-0.0046%	0.0051%
Exxon Corp.	($314,678)	$461,812	$137,242	-0.0002%	0.0003%
Shell Oil Co.	($2,010,173)	$2,888,931	$28,959	-0.0069%	0.0100%
USX-Marathon Group	($214,127)	$256,336	$15,754	-0.0014%	0.0016%
Texaco, Inc.	($645,357)	$1,044,592	$46,667	-0.0014%	0.0022%
Mariner Energy, Inc.	($60,811)	$70,795	$64	-0.0949%	0.1105%
Elf Aquitaine (France)	($37,555)	$45,802	$45,087	-0.0001%	0.0001%
Santa Fe Energy Resources, Inc.	($105,269)	$119,554	$517	-0.0204%	0.0231%
British-Borneo Petroleum Syndicate, plc (U.K.)	($1[illegible]2,009)	$225,452	$61	-0.2492%	0.3696%
British Petroleum Co. plc (U.K.)	($572,275)	$1,105,930	$71,274	-0.0008%	0.0016%
Vastar Resources, Inc.	($108,845)	$84,117	$1,014	-0.0107%	0.0083%
Falcon Offshore Operating Co.	($93,501)	$155,751	$291	-0.0321%	0.0535%
EEX Corporation	($76,177)	$202,811	$315	-0.0242%	0.0644%

Source: MMS TIMS Database, SBF Development Document, and Appendix B.

21 percent of these 12 development wells estimated to be drilled using SBFs in shallow water, or 3 wells. See Appendix B for more detailed information on numbers of wells drilled by the 18 potentially affected firms. Appendix B also presents the cost estimates for each firm broken down by type of well. These costs, when aggregated, equal the costs (with rounding) shown in Table 5-2.

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

5.1.4 Secondary Impacts

5.1.4.1 Impacts on Employment and Output

EPA anticipates no negative impacts on employment and output (revenues) from the discharge option because, in the aggregate, cost savings are realized. Changes in employment and output are directly proportional to costs of compliance (that, is higher costs lead to lower employment and output) thus cost savings would minimally increase employment and output in the oil and gas industry, but these gains would be offset by loses elsewhere in the economy (e.g., waste disposal firms). To the extent that any costs savings might be reinvested in additional drilling or otherwise encourage additional drilling, employment and output could increase in the oil and gas industry by more than that associated with the costs savings alone. EPA has not quantified this potentially positive, albeit small, effect. Under the zero discharge option, the costs of compliance are positive, leading to small loses and employment losses in the oil and gas industry. These losses, however, would be offset by gains elsewhere in the economy (e.g., waste disposal firms). The net effect of the rule on the U.S. economy under either option is likely to be close to zero.

To determine impacts on employment and output, EPA uses input-output multipliers developed by the Bureau of Economic Analysis (BEA).[4] Input-output multipliers allow EPA to calculate the total number

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[4]Bureau of Economic Analysis. 1996. “Table A-2.4-Total Multipliers, by Industry Aggregation for Output, Earnings, and Employment.” *Regional Input/Output Modeling Systems (RIMS II)*. Regional

of jobs gained or lost throughout the U.S. economy in all industries associated with a change of $1 million of output in a specific industry and the total amount of output gained or lost throughout the U.S. economy based on the change in output in the specific industry. Compliance costs or savings resulting from the SBF Guidelines can be considered equivalent to the change in output for the oil and gas industry.[5]

The BEA national level employment multiplier relevant to the oil and gas industry is 13.0, which means for every $1 million output loss, 13 jobs in the U.S. economy will be lost.

Additional output losses (those additional to output losses in the oil and gas industry) can also be calculated for a full accounting of economic losses because the losses in the oil and gas industry can lead to additional losses in related industries, such as those providing services to the oil and gas industry. BEA's final demand output multiplier allows the calculation of the total output loss to the U.S. economy as a whole based on each million dollar change in output in a particular industry. The relevant BEA output multiplier for the oil and gas industry is 1.9420, which means for every $1 million of output loss an additional $942,000 million is lost throughout the U.S. economy.

Table 5-3 presents the results of the analysis of employment and output effects stemming from the preferred discharge option as well as the zero discharge option. As the table shows, the preferred discharge option is estimated to result in employment gains of 93 full-time equivalents (1 FTE=2,080 hours and can be equated with one full-time job) and a gain of $13.9 million per year in output for the U.S. economy as a whole. The zero discharge option is estimated to result in a loss of 111 FTEs and a loss of $16.6 million per year in output for the U.S. economy as a whole (losses within the oil and gas industry would be less).

Note, however, these are not net losses and gains. Other industries, such as the waste disposal industry will lose output and employment under the discharge option and will gain output and employment under the zero discharge option. When these changes are subtracted from changes identified above, both gains and losses will be reduced. The net impact on output and employment would be close to zero under

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Economic Analysis Division.

[5]For more information on input-output analysis in the oil and gas industry, see the Coastal EIA.

Table 5-3

Employment and Output Effects Associated With SBF Guidelines Options ($1997)

Option	Compliance Cost (+)/ Cost Savings (-) ($ Millions)	Gains (+) or Loss (-) in Employment*	Total Gains (+) or Loss (-) in Output** ($ Millions)
Discharge	-$7.2	+93 FTEs	+$13.9
Zero Discharge	+$8.6	-111 FTEs	-$16.6

Source: Section Four and Bureau of Economic Analysis. 1996. "Table A-2.4-Total Multipliers, by Industry Aggregation for Output, Earnings, and Employment." *Regional Input/Output Modeling Systems (RIMS II)*. Regional Economic Analysis Division.

* Based on 13 jobs gained or lost per $1 million change in output on the affected industry.

** Based on $942,000 additional output changes in other industries in the U.S. for each $1 million change in output for the oil and gas industry.

either option. Even these gross changes in employment and output, however, are very small relative to total U.S. employment (130 million persons) and gross domestic product ($8.1 trillion) in 1997.[6]

5.1.4.2 Secondary Impacts on Associated Industries

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

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

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

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

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[6]U.S. Government Printing Office. 1998. *Economic Report of the President.*

5.1.4.3 Other Secondary Impacts

There will be no measurable impacts on the balance of trade or inflation as the result of this proposed rule. EPA projects insignificant impacts on domestic drilling and production and, therefore insignificant impacts on the U.S. demand for imported oil. Additionally, even if there were costs associated with this rule, the industry has no ability to pass on costs to consumers as price takers in the world oil market and thus this rule would have no impact on inflation.[7]

5.2 IMPACTS ON NEW SOURCES

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

As discussed above, the lack of negative economic impacts from allowing SBF discharge leads EPA to the conclusion that the effluent guidelines are economically achievable for both existing and new sources. Additionally, on a per-well basis, NSPS is expected to result in greater cost savings than BAT because new platforms do not require the retrofit costs to enable the improved solids control equipment to be placed on existing platforms. Because the preferred NSPS option results in cost savings and those cost savings are greater than those realized by existing operations, there are no barriers to entry. In fact, the rule might act as an small incentive to new source development (see discussion in Section 5.1.4.1).

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[7]Coastal EIA and Offshore EIA.

SECTION SIX

REGULATORY FLEXIBILITY ANALYSIS

6.1 INTRODUCTION

This section examines the projected effects of the costs from incremental pollution control on small entities as required by the Regulatory Flexibility Act (RFA, 5 U.S.C. 601 et seq., Public Law 96-354) as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA). The RFA acknowledges that small entities have limited resources and makes the regulating federal agency responsible for avoiding burdening such entities unnecessarily. Although EPA has certified that this rule will not have a significant impact on a substantial number of small entities, EPA has prepared an analysis equivalent to an initial regulatory flexibility analysis (IRFA).[1] Section 6.2 reviews the steps suggested in Agency guidance materials to determine whether a regulatory flexibility analysis is required and how to identify significant impacts on small businesses. Section 6.3 responds to the regulatory flexibility analysis components required for a proposed rule by Section 603 of the RFA. Section 6.4 is a detailed description of the small business economic analysis performed for the proposed regulation.

6.2 INITIAL ASSESSMENT

The following passage lists the initial assessment steps suggested in current EPA guidance.[2] The steps are posed as a series of questions and answers:

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[1] The preparation of an IRFA or any small business analysis for a proposed rule does not legally foreclose certifying no significant impact for the final rule; see U.S. EPA, 1997. *Interim Guidance for Implementing the Small Business Regulatory Enforcement Fairness Act and Related Provisions of the Regulatory Flexibility Act.* February 5.

[2] U.S. EPA, 1992. *EPA Guidelines for Implementing the Regulatory Flexibility Act.* U.S. Environmental Protection Agency, Office of Policy, Planning, and Evaluation, April; and U.S. EPA, 1997. *Op. cit.*

- Is the Rule Subject to Notice-and-Comment Rulemaking Requirements?

  The Effluent Limitations Guidelines for the Synthetic Drilling Fluids is subject to notice-and-comment rulemaking requirements.

- Profile of Affected Entities

  EPA prepared a profile of the regulated universe of entities; see Section Three and Section 6.3.2.

- Will the Rule Affect Small Entities?

  Yes.

- Will the Rule Have an Adverse Economic Impact on Small Entities?

  EPA has determined that some small entities might incur costs for incremental pollution control as a result of the rule, if a zero discharge option were promulgated. EPA examines the impacts of these additional costs in Section 6.4.

6.3 REGULATORY FLEXIBILITY ANALYSIS COMPONENTS

Section 603 of the RFA requires that an IRFA must contain the following:

- An explanation of why the rule may be needed.
- A short explanation of the objectives and legal basis for the proposed rule.
- A description of, and where feasible, an estimate of the number of small business entities to which the proposed rule will apply.
- A description of the proposed reporting, recordkeeping, and other compliance requirements (including an estimate of the types of small entities which will be subject to the requirement and the type of professional skills necessary for the preparation of the report or record).
- An identification, to the extent practicable, of all relevant federal rules which may duplicate, overlap, or conflict with the proposed rule.
- A description of "any significant regulatory alternatives" to the proposed rule which accomplish the statement objectives of the applicable statutes and which minimize any significant economic impact of the rule on small entities.

6.3.1 Need for and Objectives of the Rule

The rule is being proposed under the authority of Sections 301, 304, 306, 307, 308, and 501 of the Clean Water Act, 33 U.S.C. Sections 1311, 1314, 1316, 1317, 1318, and 1361. Under these sections, EPA sets standards for the control of discharge of pollutants for the Offshore and Coastal Oil and Gas Point Source Subcategories.

The objective of the CWA is to "restore and maintain the chemical, physical, and biological integrity of the Nation's waters." To assist in achieving this objective, EPA issues effluent limitations guidelines, pretreatment standards, and new source performance standards for industrial dischargers. Sections 301, 304, and 306 authorize EPA to issue BPT, BAT, and NSPS regulations for all pollutants.

6.3.2 Estimated Number of Small Business Entities to Which the Regulation Will Apply

The section begins with a discussion of the definition of "small business" for the purpose of responding to the requirements of the regulatory flexibility analysis, then summarizes the data available for the estimated number of small business entities and the methodology used in calculating that estimate.

6.3.2.1 Definition

The RFA and SBREFA both define "small business" as having the same meaning as the term "small business concern" under Section 3 of the Small Business Act (unless an alternative definition has been approved). The latter defines a small business at the business entity or company level, not the facility level. Furthermore, 13 CFR Part 121 defines a business concern eligible for SBA assistance as "a business entity organized for profit, with a place of business located in the United States and which makes a significant contribution to the U.S. economy through payment of taxes and/or use of American products, materials and/or labor." Additionally, "such business entity may be in the legal form of an individual proprietorship, partnership, corporation, joint venture, association, trust or a cooperative..."

The definition of "small" generally is defined by standards for each SIC code as set by the Small Business Administration (SBA). As discussed in the industry profile (see Section Three), the oil and gas industry is covered by a number of SIC codes. The predominant SIC codes also are discussed in Section Three. In SIC code 1311, Crude Petroleum and Natural Gas, SBA defines "small" as firms with fewer than 500 employees. SBA, however, states, in 13 CFR Part 121, that "number of employees means the average employment of the concern, *including the employees of its domestic and foreign affiliates* [emphasis added]." Therefore, where a firm is a subsidiary of a much larger corporate entity, the employment is considered to be the employment of the parent corporation, not the employment of the subsidiary. The analysis, then, needs to determine whether an oil or gas operator is a small business or is owned by a small business entity. This work was undertaken and presented in Section Three of this EA.

6.3.2.2 Estimated Number of Small Business Entities

In Section Three, EPA determined that as many as 41 firms drilling in the Gulf of Mexico might be considered small under SBA definitions outlined above. Furthermore one additional firm operating in the Pacific Offshore Region is considered small. No firm operating in Cook Inlet Alaska is considered small, however. Thus a total of 42 firms out of a total of 99 firms operating in the key regions (or about 42 percent) are considered small.

Small firms were profiled in detail in Section Three, which presents the number of firms and the financial profile of all firms, both large and small (where data are available). Table 6-1 presents the available financial data on the small firms in the analysis. As the table shows, EPA has relatively complete data on about 1/3 of all of the operators considered small for the purposes of this analysis. The remaining firms could not be located in SEC's Edgar database or in EPA's other data sources. For these firms, EPA used the D&B database described in Section Two to obtain revenue, SIC, and employment data for the privately held firms. Table 6-1 summarizes the financial characteristics for firms with available data, providing some additional comparative measures of financial health: a posttax return on assets ratio, a posttax return on equity ratio, and a posttax return on revenues (or profit margin).[3] The typical small firm

[3] Posttax returns are used because the OGJ 200, from which EPA obtained most of the summary financial data, presents net income. Because some small firms might not pay corporate taxes, some of

Table 6-1
Financial Data on Small Operators ($1,000s)

Operator	No. of Employees	Assets	Equity	Revenues	Net Income	Return on Assets	Return on Equity	Profit Margin (net income to total revenue)
AEDC (USA) Inc.	8			$26,104				
Aera Energy, LLC								
American Explorer	18			1,800				
Apex Oil & Gas, Inc.	3			12,000				
ATP Oil & Gas Co.	12			160				
Aviva Petroleum	10	$16,445	$3,748	9,848	($22,482)	-136.7%	-599.8%	-228.3%
Barrett Resources	207	872,701	412,381	382,600	29,261	3.4%	7.1%	7.6%
Basin Exploration	61	161,959	121,365	24,720	2,456	1.5%	2.0%	9.9%
Bois d'Arc Operating Corporation	3			280				
BT Operating Co.	35			4,819				
Cal Dive International, Inc.	400	125,600	89,369	109,386	14,482	11.5%	16.2%	13.2%
Callon Petroleum Co.	143	190,421	113,701	43,638	8,437	4.4%	7.4%	19.3%
Century Offshore Management Corp.	20			16,583				
Chateau Oil and Gas, Inc.	2			162				
Cockrell Oil Corp.	45			4,000				
Davis Petroleum Corp.	14			2,000				
Deeptech, Inc.	67	97,130	18,862	16,183	790	0.8%	4.2%	4.9%
Domain Energy Corp.	52	212,549	132,034	52,268	3,163	1.5%	2.4%	6.1%
Falcon Offshore Operating Co.	3			190				
Flextrend Development Co., LLC	3			300				
Forcenergy, Inc.	275	824,230	214,991	287,539	(134,818)	-16.4%	-62.7%	-46.9%
Forest Oil Corp.	177	647,782	261,827	339,641	(9,270)	-1.4%	-3.5%	-2.7%
F-W Oil Interests, Inc.	20			2,200				
HW & T Acquisition Company	85			19,100				
Kelley Oil	81	322,602	(5,621)	76,138	1,951	0.6%	-34.7%	2.6%
King Ranch Energy, Inc.	30			3,500				
Linder Oil Co., A Partnership	18			2,000				
Mariner Energy, Inc.	48	212,577	57,174	64,050	(20,210)	-9.5%	-35.3%	-31.6%
Matrix Oil & Gas, Inc.	20			2,200				
Meridian Resource Corp.	60	292,558	145,102	58,333	(28,541)	-9.8%	-19.7%	-48.9%
NCX Company, Inc.	11			4,452				
Newfield Exploration Co.	86	553,621	292,048	200,521	40,603	7.3%	13.9%	20.2%
Panaco, Inc.	40	179,629	55,188	38,586	43	0.0%	0.1%	0.1%
Pel-Tex Oil Co.	25			2,200				
Petsec Energy, Inc.	53	234,104	48,635	125,100	13,100	5.6%	26.9%	10.5%

Table 6-1 (continued)

Operator	No. of Employees	Assets	Equity	Revenues	Net Income	Return on Assets	Return on Equity	Profit Margin (net income to total revenue)
Pogo Producing Co.	160	$676,617	$146,106	$286,753	$37,116	5.5%	25.4%	12.9%
Snyder Oil Co.	327	546,088	263,756	255,728	32,617	6.0%	12.4%	12.8%
Stone Energy Corp.	90	354,144	156,637	70,987	11,919	3.4%	7.6%	16.8%
Taylor Energy Co.	113			41,584				
TDC Energy Corp.	20			8,182				
Transworld Exploration and Production								
W & T Offshore, Inc.	30			3,700				
Totals	2,875	$6,308,208	$2,395,269	$2,547,267	($22,546)	-0.4%	-0.9%	-0.9%
Medians (based on individual companies' figures)	37.5	$263,331	$126,700	$16,383	$2,810	1.5%	3.3%	6.8%
Minimum	2	$16,445	($5,621)	$160	($134,818)	-136.7%	-599.8%	-228.3%
Maximum	400	$872,701	$412,381	$382,600	$40,603	11.5%	26.9%	20.2%

Source: Oil & Gas Journal. OGJ 200, 1998; Pennwell Petroleum Directory, 1998; SEC's Edgar Database at http:\\www.sec.gov.
U.S. EPA Facility Index System Dun & Bradstreet Detail, 1998.

generally has smaller revenues, total assets, and owner equity than the typical large firm, but small size does not necessarily mean less healthy financially (see Table 3-4 in Section Three). Both small and large firms, on average, show strong returns on assets and equity, pretax.

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

These 42 firms comprise those firms drilling in the affected regions whether or not they are likely to be using SBFs. The only firms that are likely to experience any negative impacts are those, under the zero discharge option, that are currently using SBFs because under the preferred discharge option no wells are expected to incur costs, thus no firms would be affected in any negative way by the proposed SBF Guidelines. As discussed in Section Five, EPA assumes that the likeliest users of SBFs in shallow water are the same operators who use SBF in deep water operations. Thus the firms with both deep and shallow water operations are assumed to be the potentially affected firms. Only one firm (Mariner Energy) meets this definition as well as the SBA definition of small entity and thus would be an affected firm under the zero discharge option.

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these ratios might overstate returns by roughly a third for certain small firms.

6.3.3 Description of the Proposed Reporting, Recordkeeping, and Other Compliance Requirements

Under current law, before this rule, as well as after implementation of this rule, all affected firms are subject to monitoring and permitting requirements.

6.3.4 Identification of Relevant Federal Rules Which May Duplicate, Overlap, or Conflict With the Proposed Rule

EPA has not identified any relevant federal rules that duplicate, overlap, or conflict with the proposed rule. In fact, EPA is proposing this rule precisely because this type of drilling fluid is not appropriately controlled in existing effluent guidelines.

6.3.5 Significant Regulatory Alternatives

EPA investigated the zero discharge option, but determined that this option also would have minimal impact on nearly all firms, regardless of size, as discussed below in Section 6.4.

6.4 SMALL BUSINESS ANALYSIS

EPA undertook a revenue test, as prescribed by EPA's SBREFA Guidance, but only for the circumstance in which costs are incurred. Under the preferred discharge option, no wells are expected to incur costs, thus no firms are affected in any negative way by the proposed effluent guidelines.

EPA also looked at the impacts of the zero-discharge option. As discussed above, one firm meets the definitions of potentially affected firm and small entity and thus would be an affected small firms under the zero discharge option. EPA assumes that all wells drilled by this firm would incur costs of compliance. This is a highly conservative assumption, since overall, this firm drilled so few wells on average over 1995 to 1997 that it would be somewhat unlikely that it used SBFs at all. This firm would not experience costs exceeding 1 percent of revenues under the zero discharge option. Thus neither the discharge option nor the zero discharge option would have a significant impact on a substantial number of small entities.

SECTION SEVEN

COST-BENEFIT ANALYSIS

Pursuant to E.O. 12866, EPA chose to quantitatively and qualitatively compare the costs and benefits of the preferred discharge option. The total annual cost savings of the rule in pretax dollars are $7.2 million, including the costs to both existing and new operations. Benefits also include 72.03 tons of air emissions reduced from both existing and new sources per year (including nitrogen oxides and sulfur dioxides, and other ozone precursors). These reductions arise because operators are encouraged to use SBFs and discharge cuttings rather than use OBFs and transport wastes to shore for disposal or grind and inject cuttings). SBF use also results in an energy savings of 2,302 barrels of oil equivalent per year when the cuttings are no longer hauled to shore for disposal or ground up for injection. An additional 14.1 million pounds per year of pollutants, however, will be discharged to surface waters annually, but due to pollution prevention technology, this discharge prevents 34 million pounds of wastes from being land disposed or injected each year. See Table 7-1 for a summary of BAT and NSPS costs and benefits under the discharge option. EPA's Environmental Assessment Report provides more details on these waste reductions.[1]

Under the zero discharge option, costs would be $8.6 million, and 177.4 million pounds per year of pollutants would no longer be discharged, but instead would be land disposed or injected each year. Furthermore, 380 additional tons of air emissions would be generated annually, and energy consumption would increase by 27,057 barrels of oil equivalent per year. See Table 7-1 for a summary of BAT and NSPS costs and benefits under the zero discharge option.

[1]U.S. EPA, 1998. *Environmental Assessment of Proposed Effluent Limitations Guidelines and Standards for Synthetic Based Drillings Fluids and Other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category* (EPA-82-B-98-019).

Table 7-1

Summary of Costs and Benefits under the Discharge Option and Zero Discharge Option

Cost or Benefit Category	Discharge Option			Zero Discharge Option		
	BAT	NSPS	Total	BAT	NSPS	Total
Cost ($ million)	-$6.6	-$0.6	-$7.2	+$7.0	+$1.6	+$8.6
Energy (barrels of oil equivalent)	-2,613	+311	-2,302	+24,125	+2,932	+27,057
Solid Waste (MM lbs)	-34	0	-34	+165	+13	+178
Air Emissions (tons per year)	-73.3	+1.28	-72.02	+338.55	+41	+379.55
Water Pollutants (MMlb/yr)	+15.8	-1.6	+14.1	-159.1	-18.3	-177.4

Note: minus signs indicate a cost savings or benefit; plus signs indicate a cost or an impact.

Source: SBF Development Document and U.S. EPA, 1999. *Environmental Assessment of Proposed Effluent Limitations Guidelines and Standards for Synthetic Based Drillings Fluids and Other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category* (EPA-82-B-98-019).

APPENDIX A

COSTS OF COMPLIANCE PER WELL BY TYPE OF WELL

APPENDIX A

COST OF COMPLIANCE PER WELL BY TYPE OF WELL

Table A-1 shows the baseline cost of drill cuttings disposal, the discharge option cost under BAT requirements for both the preferred discharge option and the zero discharge option, and the incremental option costs under BAT for both options. These costs are presented in the Development Document as aggregate costs, but for the purposes of the EA, the cost per well needs to be considered. Table A-2 presents the same information for those wells that must meet NSPS requirements. Total aggregate incremental costs for both BAT and NSPS options approximately match those presented in the Development Document. Any small differences are due to independent rounding. The BAT numbers are used in Table 5-1 of the EA, and are further used to calculate the per firm costs of compliance in Appendix B and Table 5-2.

Table A-1

Incremental Per-Well BAT Costs

Type of Well	No. of Wells	Baseline Costs		Discharge Option Costs		ZD Option Costs		Incremental Discharge Option Costs		Incremental ZD Option Costs	
		Per Well	Aggregate	Per Well	Aggregate	Per Well	Aggregate	Per Well	Aggregate	Per Well	Aggregate
GULF OF MEXICO											
Deep SBF Dev (haul)	14	$117,975	$1,698,840	$88,673	$1,276,891	$213,482	$3,074,141	($29,302)	($421,949)	$95,507	$1,375,301
Deep SBF Dev (inject)	4	$117,975	$424,710	$88,673	$319,223	$175,180	$630,648	($29,302)	($105,487)	$57,205	$205,938
Shallow SBF Dev (haul)	10	$78,175	$750,480	$60,673	$582,461	$97,288	$933,965	($17,502)	($168,019)	$19,113	$183,485
Shallow SBF Dev (inject)	2	$78,175	$187,620	$60,673	$145,615	$67,620	$162,288	($17,502)	($42,005)	($10,555)	($25,332)
Shallow OBF Dev (haul)	12	$97,288	$1,167,456	$60,673	$728,076	$97,288	$1,167,456	($36,615)	($439,380)	$0	$0
Shallow OBF Dev (inject)	3	$67,620	$202,860	$60,673	$182,019	$67,620	$202,860	($6,947)	($20,841)	$0	$0
Deep SBF Expl (haul)	46	$261,575	$11,927,820	$191,073	$8,712,929	$341,388	$15,567,293	($70,502)	($3,214,891)	$79,813	$3,639,473
Deep SBF Expl (inject)	11	$261,575	$2,981,955	$191,073	$2,178,232	$389,400	$4,439,160	($70,502)	($803,723)	$127,825	$1,457,205
Shallow SBF Expl (haul)	6	$163,175	$913,780	$121,673	$681,369	$191,490	$1,072,344	($41,502)	($232,411)	$28,315	$158,564
Shallow SBF Expl (inject)	1	$163,175	$228,445	$121,673	$170,342	$141,225	$197,715	($41,502)	($58,103)	($21,950)	($30,730)
Shallow OBF Expl (haul)	6	$191,490	$1,225,536	$121,673	$778,707	$191,490	$1,225,536	($69,817)	($446,829)	$0	$0
Shallow OBF Expl (inject)	2	$141,225	$225,960	$121,673	$194,677	$141,225	$225,960	($19,552)	($31,283)	$0	$0
Total		**$1,739,423**	**$21,935,462**	**$1,288,876**	**$15,950,541**	**$2,114,696**	**$28,899,365**	**($450,547)**	**($5,984,921)**	**$375,273**	**$6,963,903**
CALIFORNIA											
Deep OBF Dev	11	$184,725	$2,031,975	$141,067	$1,551,737			($43,658)	($480,238)		
Shallow OBF Dev	1	$125,046	$125,046	$96,147	$96,147			($28,899)	($28,899)		
Total		**$309,771**	**$2,157,021**	**$237,214**	**$1,647,884**			**($72,557)**	**($509,137)**		
ALASKA											
Shallow OBF Dev	1	$207,733	$207,733	$115,467	$115,467			($92,266)	($92,266)		
Total		**$2,256,927**	**$24,300,216**	**$1,641,557**	**$17,713,892**	**$2,114,696**	**$28,899,365**	**($615,370)**	**($6,586,324)**	**$375,273**	**$6,963,903**

Source: SBF Development Document.

Table A-2

Incremental Per-Well NSPS Costs

Type of Well	No. of Wells	Baseline Costs		Discharge Option Costs		ZD Option Costs		Incremental Discharge Option Costs		Incremental ZD Option Costs	
		Per Well	Aggregate	Per Well	Aggregate	Per Well	Aggregate	Per Well	Aggregate	Per Well	Aggregate
GULF OF MEXICO											
Deep SBF Dev (haul)	14	$117,975	$1,698,840	$84,750	$1,220,400	$213,482	$3,074,141	($33,225)	($478,440)	$95,507	$1,375,301
Deep SBF Dev (inject)	4	$117,975	$424,710	$84,750	$305,100	$175,180	$630,648	($33,225)	($119,610)	$57,205	$205,938
Shallow SBF Dev (haul)	1	$78,175	$62,540	$56,750	$45,400	$97,288	$77,830	($21,425)	($17,140)	$19,113	$15,290
Shallow SBF Dev (inject)	0	$78,175	$15,635	$56,750	$11,350	$67,620	$13,524	($21,425)	($4,285)	($10,555)	($2,111)
Total		**$392,300**	**$2,201,725**	**$283,000**	**$1,582,250**	**$553,570**	**$3,796,143**	**($109,300)**	**($619,475)**	**$161,270**	**$1,594,418**

Source: SBF Development Document.

APPENDIX B

COSTS OF COMPLIANCE BY FIRM

APPENDIX B

COSTS OF COMPLIANCE BY FIRM

Tables B-1 through B-4 present the firms likeliest to use SBFs along with an estimate of the number of wells drilled annually, on average, by each of these firms according to MMS TIMS data. These tables present this information for each of the four model wells: deep water exploratory, deep water development, shallow water exploratory and shallow water development. The tables also present an estimate of the wells drilled per year by each firm using SBFs. For all deep water wells, EPA assumes that 75 percent will be drilled using SBFs, as discussed in the Development Document. The potentially affected firms therefore are assumed to use SBF to drill 75 percent of all wells they drill in deep water. For shallow water wells, EPA has taken the total number of development and exploratory wells estimated to be drilled with SBF in each year (12 shallow water development wells and 7 shallow water exploratory wells), and distributed these numbers of wells to the 18 firms according to the firms' level of activity in the shallow water of the Gulf. For example, Shell Oil is currently estimated to drill an average of 57 shallow water development wells per year. This is 21 percent of the 271 development wells drilled by the 18 firms considered to be likeliest users of SBFs in shallow water. As noted earlier, EPA estimated that 12 development wells are drilled annually with SBFs in shallow water. Shell Oil is assumed, therefore, to drill 21 percent of these 12 development wells estimated to be drilled using SBFs in shallow water, or 3 wells.

The costs of compliance for each option are taken from the incremental per-well costs shown in Table A-1 in Appendix A. These costs are multiplied by the number of wells drilled by each firm in each category of well type. Note that in some cases, 0 wells might be indicated on a table, but a small cost appears in the compliance costs columns. This occurs because the number of wells as presented in the table is rounded, but the calculation is made using the unrounded number. The total costs for each firm, when the costs of the four well types are added, equal those shown in Table 5-2 in Section Five of the EA.

Note that EPA could not determine which firms using OBFs in shallow water might switch to SBFs if allowed to discharge, so these firms are not included in Tables B-1 through B-4. These types of wells are associated with cost savings under the discharge option, but would experience no incremental costs under the zero discharge option. EPA would appreciate any information from industry regarding

Table B-1

Estimated Number of Affected Deep Water Exploratory Wells Drilled Per Year and Their Costs of Compliance

Firm	Average No./Yr. Drilled	Estimated No. Drilled w/SBF	Compliance Cost Under Discharge Option	Compliance Cost Under Zero Discharge Option
E.I. duPont de Nemours	0	0	($17,626)	$22,354
Amerada Hess Corp.	4	3	($193,881)	$245,892
Chevron USA Incorporated	2	1	($88,128)	$111,769
Occidental Petroleum Corp.	1	1	($70,502)	$89,415
Amoco Corp.	3	3	($176,255)	$223,539
Union Pacific Resources Group, Inc.	1	1	($70,502)	$89,415
Exxon Corp.	5	4	($246,757)	$312,954
Shell Oil Co.	31	24	($1,656,797)	$2,101,262
USX-Marathon Group	4	3	($193,881)	$245,892
Texaco, Inc.	9	7	($458,263)	$581,200
Mariner Energy, Inc.	1	1	($52,877)	$67,062
Elf Aquitaine (France)	1	1	($35,251)	$44,708
Santa Fe Energy Resources, Inc.	2	1	($88,128)	$111,769
British-Borneo Petroleum Syndicate, plc (U.K.)	2	2	($123,379)	$156,477
British Petroleum Co. plc (U.K.)	7	5	($352,510)	$447,077
Vastar Resources, Inc.	1	1	($35,251)	$44,708
Falcon Offshore Operating Co.	1	1	($70,502)	$89,415
EEX Corporation	0	0	$0	$0

Source: MMS TIMS Database and SBF Development Document.

Table B-2
Estimated Number of Affected Deep Water Development Wells Drilled Per Year and Their Costs of Compliance

Firm	Average No./Yr. Drilled	Estimated No. Drilled w/SBF	Compliance Cost Under Discharge Option	Compliance Cost Under Zero Discharge Option
E.I. duPont de Nemours	2	1	($36,628)	$109,809
Amerada Hess Corp.	1	1	($21,977)	$65,885
Chevron USA Incorporated	7	5	($153,836)	$461,197
Occidental Petroleum Corp.	2	2	($43,953)	$131,771
Amoco Corp.	1	1	($29,302)	$87,847
Union Pacific Resources Group, Inc.	0	0	$0	$0
Exxon Corp.	2	2	($43,953)	$131,771
Shell Oil Co.	11	8	($241,742)	$724,738
USX-Marathon Group	0	0	$0	$0
Texaco, Inc.	7	5	($146,510)	$439,235
Mariner Energy, Inc.	0	0	$0	$0
Elf Aquitaine (France)	0	0	$0	$0
Santa Fe Energy Resources, Inc.	0	0	$0	$0
British-Borneo Petroleum Syndicate, plc (U.K.)	1	1	($21,977)	$65,885
British Petroleum Co. plc (U.K.)	10	8	($219,765)	$658,853
Vastar Resources, Inc.	0	0	$0	$0
Falcon Offshore Operating Co.	1	1	($21,977)	$65,885
EEX Corporation	3	2	($65,930)	$197,656

Source: MMS TIMS Database and SBF Development Document.

Table B-3
Estimated Number of Affected Shallow Water Development Wells Drilled Per Year and Their Costs of Compliance

Firm	Average No./Yr. Drilled	Estimated No. Drilled w/SBF	Compliance Cost Under Discharge Option	Compliance Cost Under Zero Discharge Option
E.I. duPont de Nemours	17	1	(13,159)	9,909
Amerada Hess Corp.	2	0	(1,290)	971
Chevron USA Incorporated	71	3	(55,215)	41,578
Occidental Petroleum Corp.	12	1	(9,289)	6,994
Amoco Corp.	16	1	(12,385)	9,326
Union Pacific Resources Group, Inc.	2	0	(1,806)	1,360
Exxon Corp.	27	1	(20,899)	15,738
Shell Oil Co.	57	3	(44,121)	33,224
USX-Marathon Group	6	0	(4,902)	3,692
Texaco, Inc.	26	1	(20,125)	15,155
Mariner Energy, Inc.	1	0	(774)	583
Elf Aquitaine (France)	0	0	(258)	194
Santa Fe Energy Resources, Inc.	1	0	(774)	583
British-Borneo Petroleum Syndicate, plc (U.K.)	1	0	(516)	389
British Petroleum Co. plc (U.K.)	0	0	0	0
Vastar Resources, Inc.	29	1	(22,447)	16,903
Falcon Offshore Operating Co.	0	0	0	0
EEX Corporation	3	0	(2,064)	1,554

Source: MMS TIMS Database and SBF Development Document.

Table B-4
Estimated Number of Affected Shallow Water Exploratory Wells Drilled Per Year and Their Costs of Compliance

Firm	Average No./Yr. Drilled	Estimated No. Drilled w/SBF	Compliance Cost Under Discharge Option	Compliance Cost Under Zero Discharge Option
E.I. duPont de Nemours	6	0	($18,413)	$8,102
Amerada Hess Corp.	4	0	($11,252)	$4,951
Chevron USA Incorporated	8	1	($23,528)	$10,353
Occidental Petroleum Corp.	6	0	($19,436)	$8,552
Amoco Corp.	1	0	($3,069)	$1,350
Union Pacific Resources Group, Inc.	5	0	($16,367)	$7,202
Exxon Corp.	1	0	($3,069)	$1,350
Shell Oil Co.	22	2	($67,514)	$29,708
USX-Marathon Group	5	0	($15,344)	$6,752
Texaco, Inc.	7	0	($20,459)	$9,002
Mariner Energy, Inc.	2	0	($7,161)	$3,151
Elf Aquitaine (France)	1	0	($2,046)	$900
Santa Fe Energy Resources, Inc.	5	0	($16,367)	$7,202
British-Borneo Petroleum Syndicate, plc (U.K.)	2	0	($6,138)	$2,701
British Petroleum Co. plc (U.K.)	0	0	$0	$0
Vastar Resources, Inc.	17	1	($51,147)	$22,506
Falcon Offshore Operating Co.	0	0	($1,023)	$450
EEX Corporation	3	0	($8,183)	$3,601

Source: MMS TIMS Database and SBF Development Document.

which operators would be interested in switching from OBFs to SBFs in their shallow water drilling operations and how many such wells might be drilled each year with SBFs.