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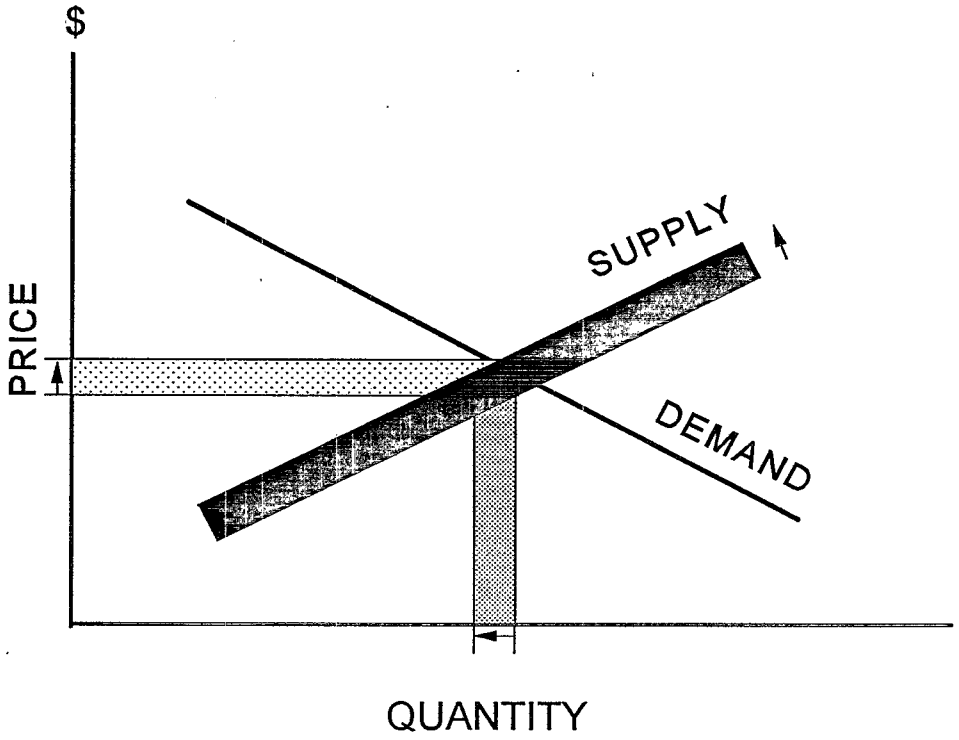

ECONOMIC IMPACT ANALYSIS FOR PROPOSED EFFLUENT LIMITATIONS GUIDELINES AND STANDARDS FOR THE COASTAL SUBCATEGORY OF THE OIL AND GAS EXTRACTION POINT SOURCE CATEGORY

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SECTION ONE

EXECUTIVE SUMMARY

1.1 OVERVIEW

This economic impact analysis (EIA) examines compliance costs and economic impacts resulting from the U.S. Environmental Protection Agency's (EPA's) proposed revisions to effluent limitations guidelines and standards for the Coastal Subcategory of the U.S. oil and gas industry. The EIA estimates economic impacts in terms of annualized costs; production losses; and changes in equity, working capital, and other indicators of financial health at the firm level. In addition, impacts on employment and affected communities, foreign trade, and new sources are considered. A Regulatory Flexibility Analysis detailing the impacts on small businesses within the coastal oil and gas industry also is included in the EIA. The impacts measured in the EIA do not take into account the requirements of the EPA Region 6 General Permits for the Coastal Oil and Gas Industry covering disposal of produced water (60 FR 2387, January 9, 1995).

This Executive Summary follows the general outline of the EIA. Section 1.2 summarizes the primary data sources used for the EIA and Section 1.3 profiles the coastal oil and gas industry. Section 1.4 presents an overview of the methodology used in the EIA, focusing on the cost annualization model. Section 1.5 presents the specific economic methodology used, which focuses on production loss modeling, and Section 1.6 investigates firm-level impacts. Sections 1.7 and 1.8 analyze employment and community-level impacts, and impacts on foreign trade, respectively. Section 1.9 presents the Regulatory Flexibility Analysis and Section 1.10 investigates impacts on new sources.

1.2 DATA SOURCES

1.2.1 The Coastal Mapping Database

This EIA relies on a number of sources of information, but primarily it uses the Section 308 Survey of the Coastal Oil and Gas Industry, which was undertaken exclusively to provide data necessary for this rulemaking. Most of the data used to determine the wells to be surveyed were developed using several existing computerized well databases covering wells in southern Louisiana and eastern Texas. Four mapping phases were undertaken using information from these databases:

- Phase I—Wells in southern Louisiana and eastern Texas were divided into offshore/federal waters, offshore/state waters, and coastal/onshore categories. A total of 508 wells were identified as located in federal offshore waters, 1,296 were identified as located in state offshore waters, and 8,778 were identified as potential coastal wells (i.e., they were not in offshore waters).

- Phase II—To simplify the task of more precisely determining whether these 8,778 wells were located in coastal areas, nonproductive wells needed to be eliminated from the analysis. Wells that were never produced—4,645 wells—were eliminated, leaving 4,133 that had produced at some time.

- Phase III—Currently nonactive wells were eliminated from consideration. Wells that were currently productive as of September 1991 were identified as active wells in the coastal database. A total of 2,710 wells were determined to be active.

- Phase IV—A number of the wells in Phase III could be clearly identified as coastal by their location in a body of water; however, hundreds of wells were further analyzed during this phase to determine their status using U.S. Fish and Wildlife Service wetlands maps and geographic information system (GIS) data.

Following the phased mapping effort, data on current ownership was purchased from the Louisiana Department of Natural Resources (DNR) and Texas Railroad Commission (RRC) and analyzed. Seventy wells were identified at this time as onshore and were dropped from the data set. The final result was a list of 354 operators and 2,640 wells in the Gulf of Mexico coastal region.

1.2.2 The Coastal Oil and Gas Questionnaire

Once the Section 308 survey universe was defined, the survey was conducted using the 1993 Coastal Oil and Gas Questionnaire. The questionnaire collected information regarding waste stream generation, treatment, and disposal; the costs of treatment and disposal; and the financial status of the firms in the coastal oil and gas industry.

EPA identified 361 operators of oil and gas wells in the coastal subcategory—354 operators in southern Louisiana and eastern Texas, and 7 operators in Cook Inlet and the North Slope of Alaska. EPA identified a population of 3,623 coastal subcategory oil and gas wells (2,640 Louisiana and Texas wells and 983 Cook Inlet and North Slope wells). The 2,640 Louisiana and Texas wells were those completed since 1980. Information on wells completed prior to 1980 was unfortunately prohibitively expensive because of the proportionately greater number of pre-1980 wells in proprietary databases. The post-1980 population of wells was divided into three subpopulations, enabling EPA to conduct a census of wells within some categories and sample wells in others. EPA conducted a census of all wells that were controlled by small operators (i.e., operators with only one well in the coastal subcategory) and all wells on multiwell structures, then sampled other wells in the population. Survey results throughout this EIA are weighted according to EPA's sampling plan. Survey results are also extrapolated in subsequent analyses to the estimated number of pre-1980 wells for which survey data are unavailable.

1.3 INDUSTRY PROFILE

The proposed effluent limitations guidelines and standards for the coastal oil and gas industry will affect a very small portion of the overall U.S. oil and gas industry. Following investigation of the current and projected oil and gas activities in the coastal region, the types of state regulations already in place, and current practices, the areas of most concern in this EIA were identified as the Gulf of Mexico coastal region of Louisiana and Texas and the coastal region of Cook Inlet, Alaska. The coastal region of Louisiana and Texas will be known as the Gulf region throughout the remainder of this EIA, since only these two states have Gulf coastal

operations known to discharge wastes. Outside of Texas and Louisiana, costs and impacts of the regulation are estimated to be zero. Due to a number of regulatory requirements already in place, wells in Alabama, Florida, California, and North Slope in Alaska are already achieving zero discharge, and no production activity is occurring or projected in Mississippi or the mid-Atlantic region of Virginia and Maryland. Table 1-1 presents information on production, number of establishments, and number of wells in Texas, Louisiana, and Cook Inlet as a portion of the U.S. oil and gas industry. Note that the estimates in this table incorporate extrapolations to pre-1980 wells, which were not surveyed.

1.3.1 Drilling and Production Activities That Generate Wastes

Two activities in the oil and gas extraction process generate the major portion of wastes in this industry: drilling activities and production activities. Because the entire subcategory except for Cook Inlet is subject to zero discharge requirements, the drilling operations of concern in this analysis are the drilling operations in Cook Inlet. The most significant waste streams, in terms of volume and constituents associated with drilling activities, are drilling fluids and drill cuttings. The major waste streams associated with production activities are produced water, and to a much lesser extent, produced sand. Miscellaneous wastes also can be generated during the productive life of a well. The three most common miscellaneous wastes are known as treatment, workover, and completion (TWC) wastes. An economic impact analysis is not being conducted on other effluent wastes generated by this industry because EPA's preferred options for these wastes are equivalent to current requirements or practices.

1.3.2 General Overview of the Affected Coastal Subcategory Industry

1.3.2.1 Trends in the Affected Coastal Subcategory

The trends of concern evaluated in this EIA are the rate at which production is expected to decline with time and the expected trend for the wellhead price of oil.

TABLE 1-1

INDUSTRY PROFILE OF THE AFFECTED SEGMENT OF THE COASTAL SUBCATEGORY: GULF COASTAL (LOUISIANA AND TEXAS ONLY) AND COOK INLET VS. TOTAL U.S. INDUSTRY

	Oil Production	Gas Production	Value of Production ($ million 1992)	Number of Employees	Number of Establishments	Number of Wells
Coastal Subcategory — Gulf of Mexico (1992) — Cook Inlet (1992)	56.4 million bbls 42.8 million bbls 13.6 million bbls	782.4 million Mcf 653.7 million Mcf 128.7 million Mcf	$2,229.3 $1,891.1 $338.2	6,197 5,403 794	440 operators 435 operators 5 operators	4,912 4,675 237
Total U.S. industry (1992)	2,624.6 million bbls	18,522.7 million Mcf	$74,510.2	180,700	7,281-13,086 establishments*	871,176
Total imports (1992)	2,222.7 million bbls	—	$38,662.5	—	—	—
Coastal industry as percentage of total U.S. industry	2.1%	4.2%	2.5%	3.4%	3.4-6.0%	0.6%
Total coastal production as percentage of total imports	2.5%	—	4.9%	—	—	—

*U.S. Bureau of the Census, 1991. The count is presented as a range because it includes establishments in SIC 131, Crude Petroleum and Natural Gas, as well as SIC 1389, Oil Field Services, Not Elsewhere Classified (5,805). This latter category is included because some of the Section 308 respondents were discovered to be operators only (i.e., they operate wells for owners, but do not own the wells). These operators would most likely be classified in SIC 1389. Note also that some of the Section 308 survey respondents that would be considered a separate establishment as reported by the Census Bureau were dropped from the Section 308 survey (and reported as duplicates) because they had the same firm-level data as another operator and were thus assumed to be the same firm. The number of duplicates totaled 23.

Source: ERG estimates based on Section 308 survey results, API (1994), and AOGA (1993).

An analysis of data used to determine the location of wells in the Gulf of Mexico coastal region reveals that well production tends to decline at a rate of 12 to 15 percent per year. The U.S. Department of Energy (DOE) estimates that overall production is declining in the United States at a rate of about 3 percent per year. The choice of decline rate affects the calculation of total lifetime production. The 3 percent national estimate and the 15 percent high-end well-specific estimate can be used to bound the decline rate for the Gulf of Mexico. Lifetime production in terms of barrels of oil equivalent (BOE) (a measure that combines units of oil and gas on the basis of Btu content) was calculated for the Gulf of Mexico region using the present (1992) estimated production of 159.2 million BOE and both the high and low estimate of potential decline over the 30-year horizon. This calculation results in a total lifetime production estimate (i.e., total production over a 30-year time frame) for the Gulf of Mexico ranging from 692.5 million to 1,391.2 million BOE.

Information provided by Cook Inlet operators indicates that the typical decline rate for Cook Inlet wells is about 8 percent per year. Expected lifetime production, based on this decline rate and the number of wells and recompletions expected to be undertaken in the Inlet, is estimated to be 198.1 million BOE with a net present value[1] of $417.2 million.

Along with production declines, revenues, employment, and other indicators of industry vitality also will tend to decline. As larger firms leave the area in search of more profitable ventures, small firms take over. Thus, the trend over time in the Gulf coastal region is toward a less highly concentrated industry (i.e., many firms, each with a very small share of the market) with many very small firms.

For the purposes of this analysis the price of oil is assumed to be constant. This assumption is consistent with current forecasts of oil prices, which indicate oil prices rising at about the same rate as inflation (i.e., the real price of oil is not expected to increase through the rest of this decade).

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[1]Total production revenues minus production costs over the lifetime of platforms in the Inlet discounted to the present.

1.3.2.2 Detailed Discussion of Wells, Facilities, and Firms

Wells or Platforms in the Coastal Region

According to estimates from the Section 308 survey, there are currently 2,548 producing wells (out of 2,640 wells in the survey universe, some of which were found to be nonproductive in 1992) in the affected coastal subcategory. The total number of pre-1980 wells is estimated to be 2,127. Therefore, the total number of Gulf of Mexico coastal wells is estimated to be 4,675. The typical Gulf coastal well produces both oil and gas. A total of 7 percent of Gulf coastal wells are gas only, 9 percent are oil only, and 84 percent produce both oil and gas. Total production in the Gulf of Mexico is estimated at 42.8 million bbls of oil and 653.7 Mcf of gas, or 159.2 million barrels of oil equivalent (BOE) annually.

There are 15 platforms located in Cook Inlet, of which 14 are considered operational or potentially operational. A total of 237 wells are currently producing on these platforms. There are also 208 oil or service wells and 29 gas wells in Cook Inlet. Total annual production in 1993 was 12.9 million bbls of oil and 120.5 Mcf of marketable gas. Total production over the remaining productive lifetime of the Cook Inlet platforms is estimated at 198 million BOE.

Produced Water Treatment Facilities in the Coastal Region

In 1992, according to permit databases provided by the Louisiana and Texas, there were 325 produced water treatment/separation facilities discharging in the Gulf coastal region. Based on compliance schedules set up by Louisiana Department of Environmental Quality (DEQ), court-ordered requirements, and results of the Section 308 survey, facilities that are required to (or that will) achieve zero discharge by the time the rule is scheduled to be promulgated (July 1996) were removed from the list of dischargers to create a list of facilities expected to be discharging in 1996, which includes 216 facilities.

The average produced water discharge rate from Gulf coastal facilities is 1,923 barrels per day (bpd) for facilities that inject produced water and 2,069 bpd for facilities that discharge

produced water. Currently, produced water treatment facilities in the Gulf of Mexico are designed to meet best practicable technology (BPT) requirements, which restrict the oil and grease concentrations of produced water to a maximum of 72 mg/L for any one day and to a 30-day average of 48 mg/L. Several technologies are used to achieve this level of control. The typical Gulf coast discharging facility uses gravity separators, which are tanks large enough to store oil and water mixtures for a sufficient length of time to allow the mixture to separate.

Because Cook Inlet is typified by multiwell platforms, the platform is considered the unit of production in the Cook Inlet analysis, and the parameters used to model production are defined by platform. There are three land-based and five platform-based separation/treatment facilities in Cook Inlet. About 98 percent of all produced water is treated and discharged from the three land-based facilities. Produced water is generated at a rate of about 127 thousand bpd in Cook Inlet. Six facilities use skim tanks only, or a combination of skim tanks and corrugated separators for treatment (four platform-based and two land-based facilities), with two facilities employing gas flotation (one land-based and one platform-based).

1.3.2.3 Oil and Gas Firms Operating in the Coastal Region

The expenditures required to comply with the effluent limitations guidelines for the coastal oil and gas industry will be financed by coastal firms and their investors. Before the impact of the effluent guidelines were assessed, the EIA evaluated the current financial condition of these firms, both generally and in comparison with the overall domestic oil and gas industry.

Firms Operating in the Gulf of Mexico

Coastal petroleum producers can be divided into two basic categories: major integrated oil companies and independents. The major integrated oil companies are generally larger than the independents. As a group, the majors generally produce more oil and gas, earn significantly more revenue and income, have considerably larger assets, and have greater financial resources than the independents, and according to the Section 308 Survey, probably are somewhat more

financially healthy than the independents as a group. Independents can be broken down by both size and by corporate structure. Larger firms tend to be corporations; smaller firms tend to be S corporations, limited partnerships, sole proprietorships, and other types of structures.

Several analyses were performed to determine the financial status of the Gulf firms. Based on the results of these analyses, several overall conclusions about the Gulf coastal operators can be made. Differences between known dischargers and all operators are probably not great and are likely to follow no particular pattern. Based on the arbitrary divisions made between groups in terms of size and corporate structure, in some cases known dischargers appear possibly a little healthier than nondischargers and in other cases the opposite appears true. Neither group is particularly financially healthy when compared to the industry as a whole. In most cases, however, on average, both known dischargers and the group of all Gulf coastal operators fall within the range between median and lowest quartile, which can be characterized as weak but not poor financial performance.

Firms Operating in Cook Inlet

The Cook Inlet operators, all majors, generally appear as healthy financially as the Gulf coast major operators as a group. Thus, they appear to have adequate to good financial health.

1.4 ECONOMIC IMPACT ANALYSIS METHODOLOGY OVERVIEW

This analysis discusses the impacts of the proposed and selected regulatory options for effluent limitations guidelines and standards for the coastal subcategory of the oil and gas production industry. The overall analysis covers:

- Compliance costs to industry.
- Production losses (in terms of quantities of hydrocarbons not produced compared to a no-regulation [baseline] scenario).

- Lost economic lifetime (i.e., the loss of productive years associated with wells shutting in earlier under the regulation than under a baseline scenario).
- Numbers of wells immediately ceasing production as a result of the regulation (first-year shut in).
- Losses of revenues to operators, in terms of annualized losses and net present value (NPV) of production,[2] state governments, and the federal government.
- Firm-level impacts (firm failure analysis).
- Employment impacts (losses and gains in employment).
- Balance of trade and inflation impacts.
- Regulatory flexibility (an analysis of whether impacts are disproportionate on small businesses).
- Impacts on new sources (which looks at impacts on NPV and the internal rate of return [another measure of profitability]).

These individual analyses are interrelated, with the output of one analysis often used as input for another analysis. The general flow of the analyses and their relationship to one another are shown in Figure 1-1. Because compliance costs (capital as well as operating and maintenance [O&M] costs) are major inputs to all of these analyses, how these costs are annualized is a key methodological decision. This EIA uses two approaches. To determine annual compliance costs, a simple annualization method that computes pretax annual costs is used. This cost is applied to wells in the Gulf of Mexico region in the production loss analysis in Section Five, and to firms in the firm-level analysis in Section Six. Platforms in Cook Inlet are modeled using a more sophisticated cost annualization method that takes into account accelerated depreciation and tax shields to compute a posttax cost faced by producers.

In the simple approach, cost annualization is used to estimate the annual compliance cost to the operators of new pollution control equipment. Annualizing costs is a technique that allocates the capital investment over the lifetime of the equipment, incorporates a cost-of-capital factor to address the costs associated with raising or borrowing money for the investment, and

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[2]NPV is the total stream of production revenues minus costs over a period of years (the well's or platform's lifetime) discounted back to present value.

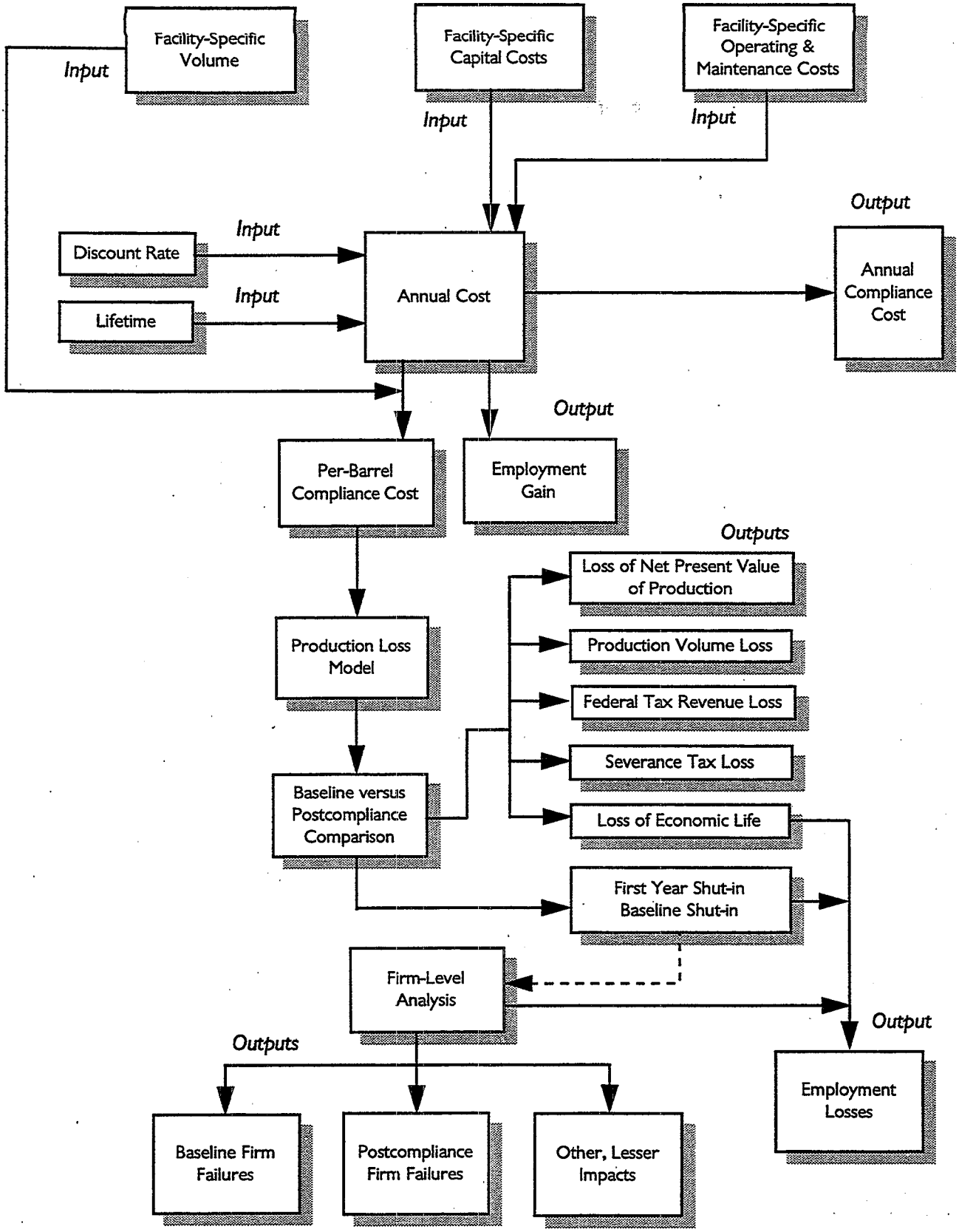

Figure 1-1. Overview of methodology for the economic impact analysis.

includes annual O&M costs. The resulting annualized cost represents the average annual payment that a given company will need to make to upgrade its facility.

The engineering cost estimates that feed into the cost annualization are based on a set of regulatory options developed by EPA. The Agency is required under the Clean Water Act to establish effluent limitations guidelines and standards of performance for industrial dischargers. To further these requirements, EPA has proposed the following effluent guidelines and standards:

- BPT—for produced sand only.
- BCT—Effluent reductions employing the best conventional pollutant control technology.
- BAT—Effluent reductions employing the best available control technology economically achievable.
- NSPS—New source performance standards covering direct discharging new sources.
- PSES—Pretreatment standards for existing sources.
- PSNS—Pretreatment standards for new sources.

For the purposes of evaluation, BCT, PSES, NSPS, and PSNS options are identical to BAT options (although preferred options differ in some cases). No existing indirect dischargers are known and no new indirect dischargers are anticipated; thus, PSES and PSNS options for indirect dischargers are not associated with any costs or impacts.

This analysis considers the BAT, NSPS, and BCT options for produced water, drilling waste, and TWC wastes. Other wastes are covered but these wastes are associated with no costs or impacts because the preferred options are equivalent to current requirements or practices. BAT options considered for each of these types of waste are summarized in Table 1-2. Five BAT options are considered for produced water, three BAT options are considered for drilling wastes, and two BAT options are considered for TWC wastes. The preferred BAT regulatory option for produced water is Option #4 (zero discharge except offshore limitations for Cook

TABLE 1-2

BAT REGULATORY OPTIONS CONSIDERED IN THE ECONOMIC IMPACT ANALYSIS

Type of Waste Stream	Name	Description
Produced water	Option #1	BPT—current regulatory requirement
	Option #2	Offshore limitations
	Option #3	Zero discharge/BPT Cook Inlet
	Option #4	Zero discharge/offshore limitations Cook Inlet
	Option #5	Zero discharge
Drilling wastes	Option #1	Zero discharge/offshore limitations Cook Inlet
	Option #2	Zero discharge/offshore limitations plus 1-million-ppm toxicity limit Cook Inlet
	Option #3	Zero discharge
TWC wastes	Option #1	BPT
	Option #2	Zero discharge/offshore limitations Cook Inlet

Inlet) and the preferred NSPS option is Option #5 (zero discharge, all). All three drilling waste options are co-proposed and the preferred NSPS option for drilling waste is NSPS=BAT (i.e., whichever BAT option for drilling waste is selected for final promulgation, NSPS will be set equal to that option). For TWC wastes, both BAT options are co-proposed, and the preferred NSPS option is NSPS=BAT. The BCT options investigated are the same as the BAT options; their selection depends on the highest option that meets the BCT cost test.

1.4.1 Aggregate Compliance Costs

1.4.1.1 BAT Options

The aggregate annual pretax compliance costs for produced water are derived from estimates of capital and operating costs for improved gas flotation and zero discharge pollution control approaches, for both the Gulf of Mexico and Cook Inlet. The aggregate annual pretax compliance costs for produced water (other than for Option #1) range from $12.4 million to $50.7 million. The selected option, Option #4, is associated with annual costs totaling $30.9 million.

Aggregate annual pretax compliance costs for drilling wastes are derived from estimates of capital and operating costs for 100,000- to 1-million-ppm toxicity limit (Option #2) and zero-discharge pollution control options (Option #3), for Cook Inlet only (operations in all other areas already practice zero-discharge). Option #1 equals BPT so there are no costs or impacts associated with Option #1. The aggregate compliance costs for drilling wastes for Option #2 are $1.4 million per year. Option #3's annual compliance costs are $3.9 million.

Annual pretax costs for disposing of TWC wastes were generated using assumptions based on Section 308 survey results about volumes discharged, numbers of wells discharging, and frequency of discharge. Because Cook Inlet platforms discharge TWC with produced wastes, all costs for TWC disposal in Cook Inlet are accounted for under produced water options. The compliance costs for disposing of TWC wastes are approximately $0 to $0.6 million annually, depending on which co-proposed option becomes final.

1.4.1.2 NSPS Cost Estimate for Produced Water

EPA estimates that six new projects will be constructed in the Gulf of Mexico each year over the next 15 years (U.S. EPA, 1995). Total capital costs for a zero-discharge option are estimated to be $2,038,738 and O&M costs are estimated to be $370,549 per year per project. The total present value of the zero-discharge option is $34.8 million with an annual cost of $4.5 million. Based on industry contacts, EPA estimates no new projects will be constructed in Cook Inlet.

1.4.1.3 NSPS Cost Estimate for TWC

EPA estimates that 45 new wells will be drilled each year and will require annual disposal of TWC fluids. Costs per year will total $78,831 for each new group of 45 wells drilled. The total present value of this outlay is $4.4 million, or $0.5 million annually. Depending on which BAT option is selected for final promulgation, NSPS costs for TWC could, thus, range from $0 to $0.5 million.

1.4.1.4 Total Estimated Cost of the Effluent Guidelines

The total estimated cost of the effluent guidelines is $30.9 to $35.4 million per year for BAT requirements and $4.5 to $5.0 million per year for NSPS requirements, for a total of $35.3 to $40.4 million per year. Thus, this rulemaking does not qualify as a major rule under Office of Management and Budget (OMB) guidelines (Executive Order 12866) and a regulatory impact analysis (RIA) is not required. Furthermore, the total annual compliance costs associated with the rulemaking are at most only 0.7 percent of annual coastal revenues (Louisiana, Texas, and Cook Inlet) and 3.3 percent of annual coastal operating costs.

1.5 ECONOMIC METHODOLOGY

A production loss model has been developed in this EIA to simulate the economic performance of coastal production and drilling projects. Analysis of Cook Inlet, Alaska, projects incorporates current and future production and future drilling in this model, while Gulf of Mexico projects are analyzed in current production scenarios only because of lack of site-specific drilling plans such as those available in the Gulf.[3] To estimate the effects of the regulatory approaches being considered, the economic performance of projects is simulated in this analysis before and after complying with new pollution control requirements (i.e., "baseline" and "postcompliance" scenarios).

1.5.1 Economic Models for Cook Inlet, Alaska, and the Gulf of Mexico

The production loss model simulates the performance and measures the profitability of a petroleum production project. For the Cook Inlet region of the coastal subcategory, a project is defined as a single platform. For each project, the model calculates the annual posttax cash flow for each year of operation as well as cumulative performance measures, such as net present value and total lifetime petroleum production. The schematic design of the model is summarized in Figure 1-2. Regulatory approaches are incorporated into the economic model by adding relevant capital costs and operating expenses to the set of cost data. The model calculates all yearly and cumulative outputs for both the baseline case and regulated cases for each project. When the results of these two scenarios are compared (external to the model itself), the incremental effects of regulation can be discerned.

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[3]The impact to new BAT wells (i.e., development wells added to existing treatment facilities without extensive site preparation work) in the Gulf coastal region should be minimal since these wells will typically face the marginal cost rather than the average cost of disposal (the cost to add an additional volume of produced water to a treatment facility, given sufficient capacity, is much less than the average cost per existing well to convert to zero discharge. Furthermore, these costs should be substantially offset by a new development well's rate of hydrocarbon production, which tends to be much greater per volume of produced water than older wells. It is unlikely that plans to drill BAT wells will be curtailed because of effluent guidelines requirements, given the large number of coastal wells currently injecting produced water. Barriers to entry for NSPS wells are addressed separately in Section Ten.

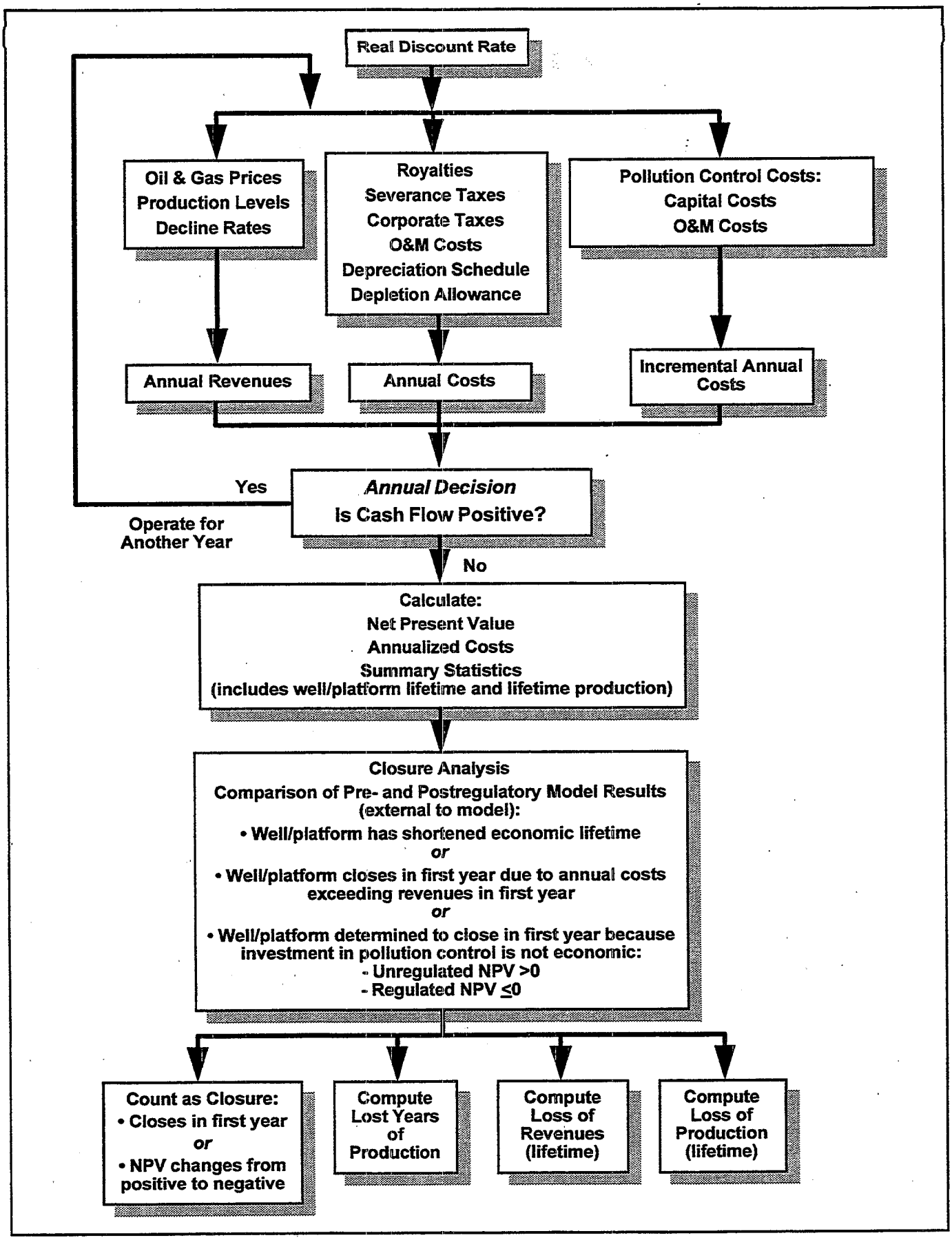

Figure 1-2. Overview of closure analysis methodology.

The methodology used in the economic model for the Gulf of Mexico is similar to the model used for Cook Inlet with some basic differences, which are discussed in Section Five. The primary difference is that the well rather than the platform is the basic unit of production modeled.

1.5.2 Production Loss Modeling Results

Production loss results are organized into baseline modeling results and postcompliance modeling results and are broken down by region within Section Five of this report. Postcompliance results include numbers of first-year shut-ins of wells or platforms by option, production losses, years of production lost, producers' losses in the present value of net income (i.e., the present value of the future stream of their net income, or net present value), and state and federal revenues lost.

1.5.2.1 Total Impacts—Gulf of Mexico Wells and Cook Inlet Platforms, Produced Water Options

As Table 1-3 shows, total produced water impacts across both regions tend to increase with option number. The selected option, Option #4, is associated with 111 wells and no platforms shutting in and losses in production totaling 15.2 million discounted BOE (which is at most 1.7 percent of total projected discounted production in the Gulf of Mexico and Cook Inlet combined) or 32.4 million total BOE. Producer's net present value (over the lifetime of the discharging wells and platforms) lost totals $153.2 million ($22.8 million annually) or at most 1.4 percent of the projected net present value of production in the Gulf of Mexico and Cook Inlet combined. Note that these losses include the producer's share of compliance costs. The present value of taxes lost are estimated at $84.9 million ($12.6 million annually), or 10.1 percent of taxes collected from discharging coastal wells and platforms in the Gulf of Mexico and Cook Inlet. The present value of severance tax losses under Option #4 totals $10.7 million ($1.6 million annually), or 3.8 percent of projected baseline collections in the Gulf of Mexico and Cook Inlet among discharging coastal wells and platforms. Finally, royalties lost to the states total

TABLE 1-3

TOTAL ECONOMIC IMPACTS (INCLUDING PRODUCTION LOSSES): GULF OF MEXICO AND COOK INLET REGIONS COMBINED (Produced Water Only)

	Option #1	Option #2	Option #3	Option #4	Option #5
Number of wells and platforms shut in	0 wells 0 platforms	42 wells 0 platforms	111 wells 0 platforms	111 wells 0 platforms	111 wells 3 platforms
Lifetime production lost (million discounted BOE)	0	12.5	12.1	15.2	28.0
Total lifetime production lost (million BOE)	0	27.6	27.8	32.4	50.2
Present value of producers' net income lost ($000)	0	$114,651	$144,48	$153,209	$235,970
Present value of federal/state income taxes lost ($000)	0	$61,320	$79,651	$84,903	$119,822
Present value of lost severance taxes ($000)	0	$5,592	$10,517	$10,676	$11,341
Present value of lost royalties ($000)	0	$21,007	$29,058	$34,255	$57,822
Total losses (includes compliance costs) ($000)	0	$202,570	$263,706	$283,043	$424,955

Source: ERG estimates.

$34.3 million ($5.1 million annually), or 5.1 percent of projected baseline royalties paid to the states in the Gulf of Mexico and Cook Inlet from discharging coastal wells and platforms. Note that if taxes and royalties from nondischargers are considered, these percentages of income lost would be much lower, given that in 1996 discharging wells will make up only about a third of all Gulf coastal wells.

1.5.2.2 Total Impacts—Drilling Options

Option #1

Option #1 results in no costs or impacts.

Option #2

Option #2 requires drilling wastes to meet a 100,000- to 1-million-ppm toxicity limit, in addition to offshore requirements. Under this option, there is a loss of lifetime production in Cook Inlet of 2.7 million discounted BOE (3.6 million total BOE), or 1.4 percent of total lifetime Cook Inlet production (stemming from three wells that will not be drilled under this scenario); no platforms shut in during the first year; and the present value of net producer income falls by $0.3 million ($0.04 million annually),[4] or less than 0.1 percent of baseline net present value. Average platform lifetime decreases by only 0.2 years (2 months). The present value of state severance tax collections falls by $133,000 ($19,000 annually, on average over the 11-year life of platforms under this option, or 0.2 percent of baseline) and the present value of royalties decreases by $4.3 million ($0.6 million, on average, annually, or 1.6 percent of baseline). The present value federal tax collections falls by $2.6 million over the life of the platforms ($0.4 million, on average, annually), or 1.1 percent of projected baseline collections.

[4]This small loss results from baseline assumptions. See Section Five for more details.

Option #3

Option #3 requires zero discharge of all drilling waste. Under this option, no platforms shut in during the first year, but six wells that are planned to be drilled will not be drilled. The total lifetime production lost is estimated to be 5.4 million discounted BOE (7.8 million total BOE), or 2.8 percent of lifetime baseline production. Producers' net present value lost totals $6.1 million ($0.9 million annually), which is 1.5 percent of total baseline net present value. The average number of production years per platform under this option is 10.2 years, vs. 11.1 years in the baseline scenario, a loss of about 1 year.

The present value loss of federal income tax over the lifetime of the platforms is projected to be $7.9 million ($1.2 million, on average, annually over the 10-year life of platforms under this option, or 3.4 percent of baseline federal income taxes), with the present value of severance tax losses totaling $0.3 million ($0.04 million, on average, annually, or 0.5 percent of baseline severance taxes). The present value of royalty losses to the state totals $9.4 million ($1.4 million, on average, annually), or 3.7 percent of the baseline royalties collected. Total present value losses to the state from royalties and severance taxes lost are, thus, $9.7 million ($1.44 million, on average, annually).

1.5.2.3 Impacts From the Regulatory Options for TWC Wastes

Costs of disposing of TWC wastes range from $0 to $605,645 annually for all Gulf of Mexico wells estimated to currently discharge TWC wastes (a minimum of 334 wells in 1992), or at most an average of $1,813 per well under Option #2. A typical Gulf of Mexico well produces an average of 36 barrels of oil per day according to the 1992 Coastal Oil and Gas Questionnaire. At $18 per barrel, total production revenue at a typical well is estimated to be $237,000 per year. Thus, TWC waste disposal costs are estimated to be at most 0.8 percent of average annual production revenues at a typical Gulf of Mexico well, and no major impacts are expected as a result of either co-proposed option.

TABLE 1-4

TOTAL ECONOMIC IMPACTS TO GULF OF MEXICO AND COOK INLET REGIONS FROM THE SELECTED OPTIONS[a]

	Option #4 Produced Water	Option #2 Drilling Waste	Option #3 Drilling Waste	Total Impacts With Option #2 Drilling Waste	Total Impacts With Option #3 Drilling Waste[b]
Number of wells and platforms shut in	111 wells 0 platforms	0 wells 0 platforms	0 wells 0 platforms	111 wells 0 platforms	111 wells 0 platforms
Discounted production lost (million BOE)	15.2	2.7	5.4	15.2	17.9
Total production lost (million BOE)	32.4	3.6	7.8	32.4	40.2
Net present value (NPV) of production lost ($000)	$153,209	$263	$6,089	$154,584	$160,409
Present value of federal taxes lost ($000)	$84,903	$2,586	$7,925	$85,611	$90,950
Present value of lost severance taxes ($000)	$10,676	$133	$272	$10,676	$10,815
Present value of lost royalties ($000)	$34,255	$4,274	$9,394	$34,255	$39,375
Total present value of losses ($000)	$283,043	$7,256	$23,680	$285,126	$301,549

[a]Economic impacts from selected options for other regulated waste streams are expected to be negligible on these results.

[b]Economic impacts are not additive. Some double counting or undercounting of impacts occurs in the Cook Inlet analysis if produced water impacts are directly added to drilling waste impacts. The total reflects the removal of double counting and inclusion of synergistic impacts (see Table 5-8).

Source: ERG estimates.

1.5.2.4 Total Impacts for all Selected Options

Total maximum impacts for all selected BAT regulatory options (i.e., Option #4, produced water, and Option #3, drilling waste)[5] are estimated to be as follows (see Table 1-4): 111 wells are expected to shut in; up to 17.9 million discounted BOE (40.2 million total BOE) are estimated to be lost (1.1 to 2.0 percent of projected baseline production in the Gulf of Mexico and Cook Inlet coastal regions); and up to $160.4 million in net present value of income ($23.9 million annually) is expected to be lost (0.7 to 1.5 percent of the NPV of production in the Gulf of Mexico and Cook Inlet coastal regions).

The maximum present value of federal and state income taxes lost totals $91.0 million ($13.6 million on average annually—primarily federal), which is 10.8 percent of projected lifetime income taxes in the baseline collected among discharging wells and platforms. The maximum present value of state severance taxes lost totals $10.8 million ($1.6 million on average annually), or 3.8 percent of projected lifetime severance taxes in the baseline collected among discharging wells and platforms. Finally, the maximum present value of royalties lost totals $39.4 million ($5.9 million on average annually), or 5.8 percent of projected lifetime royalties in the baseline collected among discharging wells and platforms. Note that impacts on taxes and royalties are substantially less if taxes and royalties collected from nondischarging wells also are considered. Total economic impacts (including compliance costs) are as much as $301.5 million present value ($44.9 million annually).

Impacts from Options #4, produced water, and drilling waste Options #2 and #3 are not additive for Cook Inlet platforms (note that impacts for Option #4, produced water, and Option #1, drilling waste, are the same as Option #4, produced water, impacts alone). A small double counting and under counting of impacts occurs.

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[5]The actual total will depend on drilling waste option and will range as low as the impacts estimated for Option #4, produced water, alone, discussed in Section 1.5.1.2)

1.6 ECONOMIC IMPACTS ON COASTAL OIL AND GAS FIRMS

The firm-level analysis conducted in the EIA evaluates the effects of regulatory compliance on firms owning one or more affected coastal oil and gas operators. It also serves to identify impacts not captured in the production loss analysis.

This analysis was conducted in three stages: a baseline analysis; a screening analysis; and finally, a detailed analysis. In the baseline analysis, firms with negative equity and working capital are considered baseline failures and removed from further postcompliance analysis. In the screening analysis, the annual costs of meeting either an oil and grease limit based on improved gas flotation or zero-discharge requirement are subtracted from each firm's equity and working capital and the percentage decrease in equity and working capital is then calculated. These declines are compared to a benchmark of 5 percent (i.e., a count is presented of the number of firms having their equity or working capital reduced by more than 5 percent as a result of a regulatory option). In the detailed analysis, all firms with a 5 percent or greater change in either equity or working capital are investigated using all available survey information and additional financial indicators to refine the initial estimates of potentially substantial impacts on coastal oil and gas firms.

Sources of data used in these analyses include two databases that provide information on permit numbers, permit holders, discharge volumes, field names, and other data that EPA received from the states of Louisiana and Texas. Also used with the permit data are data from the Section 308 survey. Surveyed Gulf of Mexico firms were linked with known permit holders in the databases. For several reasons, not all permit holders are included in the Section 308 survey. Because only 58 surveyed operators with sufficient financial data could be linked to the 122 operators identified in the permit databases as discharging in 1996, estimates of impacts assume that only half of the relevant operators were captured in this analysis. It is further assumed that this sample of operators is unbiased, and, thus, estimates of impact are extrapolated to the entire coastal universe of operators by multiplying results by two.

These data are used to identify impacts on firms. For the purpose of this analysis, costs for meeting no-discharge requirements for the permitted facility are assumed to fall solely on the operator who holds that facility's permit.

1.6.1 Results of Baseline Analysis/Screening Analysis

1.6.1.1 Gulf of Mexico

Five of the 58 matched firms (9 percent) in the Gulf of Mexico region currently have both negative equity and negative working capital. These firms are considered very likely to fail the baseline analysis regardless of whether any regulatory actions are taken. Thus, 53 firms were analyzed in the screening analysis.

All Gulf of Mexico coastal oil and gas firms matched in the analysis database were investigated to determine changes in equity and working capital resulting from outlays for incremental disposal costs (produced water costs) by size of firm. Of the firms with positive equity, 23 small firms and all large firms are expected to experience a change in equity of less than 5 percent if improved gas flotation is used. If zero discharge were required, no additional small firms would be expected to experience a change in equity of greater than 5 percent.

Sixteen small firms (40 percent of small firms with positive working capital) and all large firms would be expected to experience changes in working capital of less than 5 percent if improved gas flotation were used to meet limits. If zero discharge is required, no additional firms would be expected to experience a change in working capital of greater than 5 percent.

1.6.1.2 Cook Inlet

None of the five operators in Cook Inlet are expected to experience a change in equity or working capital of greater than 5 percent under either the option for limits based on improved

gas flotation or the zero discharge option for produced water or under the 1-million-ppm toxicity limit or zero-discharge limit for drilling waste. No further analysis of these firms is undertaken.

1.6.2 Results of Detailed Analysis of Firms in the Gulf of Mexico Region

A number of firms were selected for more in-depth analysis of survey responses in an attempt to identify conditions that would indicate substantially less impact than that suggested by the use of a 5 percent change in equity and working capital. Of the small firms not identified as baseline failures, 18 small firms were identified for further analysis.

Of these 18 firms, 4 are considered additional baseline failures and 1 is expected to have already plugged and abandoned the wells that are served by its discharging facility before the time that the effluent guidelines take effect. Of the remaining 12 firms, 3 firms are not expected to fail but are expected to plug and abandon wells or sell their wells in response to the regulation (considered a nonmajor impact). Another 3 firms are expected to experience some impacts, but not to the extent that firm failure is likely. The remaining six firms lack the information needed to rule out the possibility of firm failure, although it is very possible that no substantial impact will actually occur at these firms.

Thus, under either the improved gas flotation or zero-discharge options, a range of 0 to 6 firms might experience firm failure out of a total of 58 operators examined in this analysis (since as few as none might actually fail). Because there are a total of 122 operators discharging, or roughly twice the number of operators examined (58 operators screened), the number of firms experiencing firm failure for all discharges is extrapolated to be a range of 0 to 12 firms. The upper estimate assumes that firms for which information is lacking will be substantially affected. Thus, the upper bound of this range might overestimate the impacts considering the level of uncertainty associated with the majority of observations. Based on the total number of firms estimated to be operating in the Gulf of Mexico in the postcompliance scenario—435 firms

minus 18 baseline failures,[6] or 417 firms—these 0 to 12 potentially substantially affected firms are 0 to 2.9 percent of the Gulf of Mexico segment of the oil and gas industry.

1.7 EMPLOYMENT AND COMMUNITY-LEVEL IMPACTS

The EIA assesses employment and community-level impacts resulting from compliance with the proposed effluent limitations guidelines for the coastal oil and gas industry.

1.7.1 Primary and Secondary Employment Losses

Compliance imposes a cost at both the well and the firm level, which might result in well shut-ins and firm failures and thereby a loss in employment. Primary employment losses occur only within the portion of the coastal oil and gas industry that discharges wastes. These job losses are estimated from survey data on annual employment hours. Secondary impacts include employment losses in other industries providing inputs to the coastal oil and gas industry and other supporting industries. These impacts are assessed through multiplier analysis, which measures the extent of impacts in other industries as a function of impacts in the primary industry. The multiplier used in this analysis is based on input-output tables developed by the U.S. Department of Commerce, Bureau of Economic Analysis (BEA). Primary and secondary employment losses are summed to obtain the total impact on community employment levels resulting from implementation of the effluent guidelines.

Employment losses are counted when a well shuts in (100 percent of the per-well employment) and when a firm fails (100 percent of nonproduction employment). Total employee hours lost because of well shut-in, or firm failure are expressed in full-time equivalents (FTEs) assuming that 2,080 hours (52 weeks/year x 40 hours/week) equals 1 FTE. Table 1-5 presents the results of primary employment losses in the baseline. The table shows that, before any

[6]There are 5 baseline failures, plus 4 postanalysis baseline failures. These are multiplied by two to extrapolate to all dischargers.

compliance costs are incurred, 281 jobs are estimated to be lost, out of a total Gulf and Cook Inlet employment of 6,197 workers (4.5 percent of total employment in the affected portion of the industry), all occurring in the Gulf of Mexico region. (No baseline employment losses are projected for Cook Inlet.) The baseline analysis predicts that secondary job losses will total 807 using the secondary employment multiplier of 2.86 estimated for the Gulf of Mexico region based on BEA data. These baseline losses constitute an insignificant portion of national employment and have a negligible impact on national-level employment rates.

Table 1-5 also presents postcompliance employment losses by region and by type of loss for each of the regulatory options considered in this analysis for produced water and drilling waste. Total employment losses associated with produced water options (not including Option #1) are estimated to range from 101 FTEs for Option #2 (1.7 percent of combined Gulf of Mexico and Cook Inlet employment) to 290 FTEs for Option #5 (4.9 percent of combined Gulf of Mexico and Cook Inlet employment, which, postbaseline, is estimated to be 5,916 FTEs). The selected produced water option (Option #4) combined with any drilling waste option are associated with losses totaling 181 FTEs (or 3.1 percent of combined Gulf of Mexico and Cook Inlet employment). Based on the multiplier of 2.86 percent for the Gulf of Mexico, total primary and secondary losses will total 518 FTEs.

An additional employment impact will also occur. On average, in the baseline, wells are expected to have a projected 15-year productive lifetime in the Gulf (in Cook Inlet, the change in platform life is considered negligible). Under either Options #2 or #3 through #5 for produced water, the productive lifetime drops to around 10 years. Thus, an estimated 1,561 FTEs will be lost in 10 years rather than in 15 years. This loss is equivalent to a 3 percent decline per year in employment versus a 2 percent per year decline under the baseline scenario, or in annual terms (i.e., lost FTEs discounted to the present and annualized), 337 FTEs per year. This figure is considered a maximum. If wells are shut in in a pattern resembling a normal distribution, a more realistic estimate would be less than 169 FTEs. This impact is not added to first-year employment losses because these impacts occur, on average, about a decade hence. Because employees have ample time to find alternative sources of employment, and natural attrition might take care of the bulk of employment declines, these impacts are considered minor (even when discounted) compared to first-year losses.

TABLE 1-5

BASELINE AND POSTCOMPLIANCE EMPLOYMENT LOSSES (FTEs)

Option	Gulf of Mexico			Cook Inlet			Total Employment Losses All Regions	Mid-point of Employment Losses
	Losses from Immediate Shut-ins	Losses from Firm Failure	Total Employment Losses	Losses from Shut-ins	Losses from Firm Failure	Total Employment Losses		
Produced Water								
Option #1	0	0	0	0	0	0	0	0
Option #2	49	0-104	49-153	0	0	0	49-153	101
Option #3	129	0-104	129-233	0	0	0	129-233	181
Option #4	129	0-104	129-233	0	0	0	129-233	181
Option #5	129	0-104	129-233	109	0	109	238-342	290
Drilling Waste								
Option #1	0	0	0	0	0	0	0	0
Option #2	0	0	0	0	0	0	0	0
Option #3	0	0	0	0	0	0	0	0
Selected Options Combined								
Option #4-Produced Water, Option #1, #2, or #3-Drilling Waste	129	0-104	129-233	0	0	0	129-233	181
Baseline								
Baseline	226	86	281	0	0	0	281	NA

An increase in the community employment rate due to compliance with the regulation equal to or greater than 1 percent is considered significant by EPA. This impact would correspond to a considerable change in the community employment rate. Based on an "average" county within the Gulf of Mexico coastal region (i.e., a county with average population and employment rate), and assuming all losses occur within this one composite county, employment is expected to decline no more than 0.3 percent. The decline in employment rate in any one community in the Gulf of Mexico region, however, will be much less than this 0.3 percent.

1.7.2 Labor Requirements and Potential Employment Benefits

Firms will need to install and operate pollution control systems to comply with effluent limitations guidelines for the coastal oil and gas industry. The manufacture, installation, and operation of these systems will require use of labor resources. EPA analyzed each of the components of direct labor requirements separately. The sum of the estimated requirements for the three labor categories represents the estimated total direct labor requirement, and, thus, the potential direct employment benefit, from compliance with the effluent guidelines.

As Table 1-6 shows, the labor associated with manufacturing the compliance equipment is estimated to be up to 52 FTEs per year (depending on which drilling waste options are selected) associated with the Gulf of Mexico and Cook Inlet operations (46 FTEs Gulf of Mexico and 5 to 6 FTEs Cook Inlet).

A total of up to 56 FTEs per year (51 FTEs in the Gulf of Mexico and 4 to 5 FTEs in Cook Inlet) are associated with installing the compliance equipment. A total of up to 31 FTEs per year (27 FTEs Gulf of Mexico and 1 to 5 FTEs Cook Inlet) will be required to operate the equipment.

Summing the three components yields the total direct labor requirements for complying with the proposed coastal oil and gas industry effluent guidelines as represented by the selected regulatory options. On an FTE basis, the estimated total annual labor requirement is 124 FTEs (Gulf of Mexico) and 10 to 15 FTEs (Cook Inlet), depending on drilling waste requirements, for

TABLE 1-6

TOTAL ESTIMATED DIRECT EMPLOYMENT GAINS: GULF OF MEXICO AND COOK INLET REGIONS

	Annual Labor Cost			Annual Basis Employment Gains (FTEs)
	With Option #1 Drilling Waste	With Option #2 Drilling Waste	With Option #3 Drilling Waste	
Manufacturing	$2,633,124	$2,698,986	$2,698,986	51-52
Installation	$3,146,384	$3,225,084	$3,225,084	55-56
Operation (annually)	$1,625,155	$1,664,505	$1,798,160	28-31
Total direct labor effects	$7,404,663	$7,588,575	$7,722,230	134-139

a total of up to 139 FTEs. This number must be offset, however, by the employment gains that will not occur as a result of the effluent guidelines. A total of 10 to 20 FTEs might not be added to the labor force under the combined produced water and drilling waste options proposed because of wells not drilled (and, thus, never produced). Thus, 119 to 127 FTEs might be added as a result of the regulation. For simplicity, 119 FTEs gained is used to estimate net labor effects.

In addition to direct labor effects, the coastal oil and gas industry effluent guidelines might also generate labor requirements through the indirect and induced effect mechanisms, thereby generating secondary employment. The secondary effects associated with an economic activity are analyzed by using multipliers. Two multipliers were used—one for equipment and installation employment gains and one for operating employment gains. The indicated aggregate employment effects associated with the direct labor requirement of 119 FTEs would be 397 FTEs under the highest impact scenario (Option #4, produced water, and Option #3, drilling waste).

1.7.3 Net Effect of Employment Losses and Gains

The primary employment gains (119 FTEs) are expected to partially offset primary employment losses (181 FTEs under all the combinations of the preferred produced water option and the co-proposed drilling waste options). Thus, net primary losses might be 62 FTEs. Primary and secondary gains of 397 FTEs are expected to offset partially the primary and secondary loss of 518 FTEs estimated above. The net effect on employment therefore might be 121 FTEs lost. The net employment impact is negligible when compared to national-level employment and will have no impact on national-level employment rates.

1.8 IMPACTS ON THE BALANCE OF TRADE, INFLATION, AND CONSUMERS

Although the costs and economic impacts of the BAT and NSPS regulations will fall primarily on the coastal oil and gas industry including its employees, other secondary effects in other sectors of the economy would also occur. The United States has recently entered a time

when oil imports exceed total oil production. Unless domestic demand for oil is curbed, the United States will continue to import a growing percentage of the supply needed to satisfy domestic consumption. Under Option #4, for produced water (the selected option), and with Cook Inlet meeting zero discharge of drilling waste, total lifetime production declines are only up to 2.0 percent of total lifetime coastal production. This is a small percentage considering decline in domestic production is estimated to be occurring at 3 percent *per year*. The negative change in the balance of trade expected from the rulemaking will not be significant compared to changes caused by other factors.

The regulations can lead to higher costs to the operators. Because of the inability of the companies to raise prices in response to increased costs, however, no substantial impacts on inflation are likely from increased costs of pollution controls on coastal oil and gas effluents. Therefore, this rulemaking will have no substantial distributional impacts, since consumers of oil products will not be facing higher prices as the result of higher domestic producer costs.

1.9 REGULATORY FLEXIBILITY ANALYSIS

EPA guidelines require EPA Offices to perform Regulatory Flexibility Analyses (RFAs) for regulations that have *any* effect on *any* small entities. An Initial Regulatory Flexibility Analysis (IRFA) was performed in this EIA for the proposed effluent guidelines and standards for the coastal oil and gas industry to determine their effect on small firms. The IRFA estimates 86 percent of the 435 firms in the survey universe are small firms.

Two measures are used in this EIA to determine whether disproportionate impacts are occurring among small firms: the firm failure analysis and a screening analysis of impacts measured as changes in equity and working capital. (This analysis is only performed for Gulf firms; all firms in Cook Inlet are large.)

In Section Six, the EIA examines firm-level impacts by screening firms to determine potential impacts on equity and working capital assuming that annual costs would be paid for either through increased liabilities or by using working capital. Where annual costs exceed 5

percent of either equity or working capital, the potential for significant impacts is considered in more detail. The only firms in the sample considered in Section Six that are identified as concerns are small firms. Most of these firms were not considered likely to fail, however, when analyzed in more detail. Only six firms in the sample (representing 12 firms overall in the Gulf of Mexico region) were further identified as possible firm failures. Out of the 354 small firms in the estimated (postbaseline) survey universe, however, the 12 possible firm failures represent only a maximum of 3.4 percent of small firms and only 2.9 percent of all Gulf coastal oil and gas firms.

It is important to note that most coastal oil and gas firms in the Gulf coast region (as of 1996) will not be discharging wastes. Only 29 percent of the coastal oil and gas firms are estimated to be discharging any produced water as of 1996. Thus, the typical small oil and gas firm (represented as the median firm) *is estimated to incur no compliance costs whatsoever.* Moreover, compliance costs as a percentage of the present value of net income at the median small firm (as well as at the median large firm) in the coastal oil and gas industry will be zero, even if net income declines slightly over time. Thus, the typical small coastal oil and gas firm will not be disproportionately affected by the proposed effluent guidelines as compared to the typical large coastal oil and gas firm.

1.10 IMPACTS ON NEW SOURCES

In most cases, the selected NSPS and PSNS regulations have been set equal to the selected BAT options and, thus, are considered to pose no significant barrier to entry. Impacts on new sources in Cook Inlet from the NSPS requirements for produced water, however, need to be addressed. Based on the analyses performed for the Offshore Effluent Guidelines (which continue to be relevant analyses for the Coastal Effluent Guidelines since the same financial model was used in the offshore analysis to determine impacts on Cook Inlet platforms, which were being considered for inclusion in the offshore subcategory), EPA concludes that impacts on new sources in Cook Inlet are minimal and the NSPS requirements should not pose significant barriers to entry for two reasons: (1) declines in returns (measured as net present value and internal rate of return) are very small and most likely will not affect the decision to undertake a

new project (i.e., profitability of new projects will not be substantially affected by the regulation), and (2) estimated impacts on new sources from NSPS requirements are not substantially greater than those estimated for existing sources from BAT requirements.

SECTION TWO

DATA SOURCES

2.1 INTRODUCTION

This EIA uses a number of sources of information, but primarily it uses the Section 308 Survey of the Coastal Oil and Gas Industry, which was undertaken exclusively to provide data necessary for this rulemaking. The coastal oil and gas industry is difficult to analyze using secondary sources of information because it is an especially small subset of the U.S. oil and gas industry and this designation is not used by any other federal or state agency or industry; so no data have been collected under this definition. Moreover, this subset is an unusual subset because most of the operations are conducted in shallow to relatively deep waters, although not as deep as waters that are typical for offshore oil and gas industry operations. Unlike the offshore oil and gas industry (which tends to have well-defined secondary source data), little to no data specific to the wells in the coastal region are available (with the exception of Cook Inlet and California).

The data that are available on the U.S. oil and gas industry tend to reflect either offshore conditions (deep water) or onshore conditions. Many onshore or offshore parameters are not likely to be representative of most coastal operations. The coastal subcategory does include some wells that can appear similar to onshore wells; however, before the survey was undertaken, the number of operations that could be considered similar to onshore operations was not known (it is not the major portion of coastal operations, however). Further, since very few multiwell platforms operate in the coastal region outside Cook Inlet and California, and those that do have fewer than four wells on them (ERG, 1994), few if any operations will resemble the offshore industry operations.

Thus, secondary source information is used where necessary in this EIA, but mostly to compare the coastal industry to the overall U.S. industry. Such sources include, among others, the American Petroleum Institute's (API's) *Basic Petroleum Data Book*, Dun & Bradstreet

statistics on financial indicators, and *Oil and Gas Journal* articles on price and production trends in the United States. Additional primary sources of information include contacts within the industry and in the key coastal region states and permit databases from Louisiana and Texas covering wells and discharging produced water treatment facilities.

The first step in collecting data on the coastal oil and gas industry was to determine who was operating in the coastal region and how many wells were involved. The key area of concern was the Gulf of Mexico region with its many bays, harbors, bayous, lakes, rivers, and wetlands, which form the key identifiers of potential coastal well locations. EPA determined that the only way to identify the likely affected population in southern Louisiana and east Texas was to identify the location of the wells in relationship to the various waterbodies in this region.

Section 2.2 describes this mapping effort and the creation of a location database, which was used to identify a large portion of the affected operators in the Gulf of Mexico. Section 2.3 then describes how the identified operators and their wells were selected, sampled, and surveyed in the Section 308 survey.

2.2 THE COASTAL MAPPING DATABASE

The primary source of data used to determine the Section 308 survey universe was developed using several computerized databases purchased and/or obtained from Tobin Surveys, Inc. (Tobin), Petroleum Information (PI), the Louisiana Department of Natural Resources (DNR), and the Texas Railroad Commission (RRC). Tobin compiles information on wells by geographic location. Because of expense, the number of records (wells) that could be purchased needed to be limited. A polygon of the Gulf of Mexico area was developed to identify well locations that were considered likeliest to meet the definition of coastal (see Section 3.1 for the definition of the coastal subcategory). This polygon, defined by longitudes and latitudes, was provided to Tobin, which created a custom data set of wells. This data set included only wells

completed after 1980.[1] The total count of all wells in the polygon, both productive and nonproductive, was 56,220 wells (ERG, 1992). The total number of wells for which data were purchased from Tobin was 10,582. Tobin also supplied location maps of all wells in the polygon.

Four mapping phases were undertaken:

- Phase I—Wells were divided into offshore/federal waters, offshore/state waters, and coastal/onshore categories. This task was performed by comparing well locations with the "baseline," a line developed by Avanti Corporation that marks the boundary of the territorial seas (see coastal definition in Section Three, and Avanti, 1991). A total of 508 wells were identified as located in federal offshore waters, 1,296 were identified as located in state offshore waters, and 8,778 were identified as potential coastal wells (i.e., they were not in offshore waters).

- Phase II—To simplify the task of more precisely determining whether these 8,778 wells were located in coastal areas, nonproductive wells needed to be eliminated from the analysis. Wells that were never produced—4,645 wells—were eliminated, leaving 4,133 that had produced at some time.

- Phase III—Current productivity status could not be determined from Tobin data because of infrequent updates to this database. Thus, PI's more frequently updated database was used to eliminate currently nonactive wells from consideration. The PI and Tobin databases were merged using the 10-digit API number that is used to identify uniquely all oil and gas wells. Wells that were currently productive as of September 1991 were identified as active wells in the coastal database. A total of 2,710 wells were determined to be active.

- Phase IV—A number of the wells in Phase III could be clearly identified as coastal by their location in a body of water; however, hundreds of wells needed further analysis to determine their status using wetlands maps. For Texas wells, U.S. Fish and Wildlife Service (FWS) wetlands maps were used. The "unknown" wells were plotted onto overlays of the same size and scale as the FWS wetlands maps. Then the overlays were placed on the wetlands maps and each well was manually identified and coded as to location (e.g., in a riverine, lacustrine, or palustrine wetland or onshore) in the database. For Louisiana wells, computerized wetland information had been compiled, and Louisiana State

[1]Pre-1980 wells were not identified or surveyed, although estimates of those wells likely to be still active in the coastal region are estimated in Section Three. The decision to cut off data at 1980 was made because many wells completed prior to 1980 are likely to be no longer active and the expense to obtain the data for and map these wells was prohibitive. The wells not surveyed are limited to those that have not been completed or recompleted to produce from another zone since 1980. Results of economic impacts, however, are extrapolated to these wells throughout this EIA.

University was contracted to merge geographic information system (GIS) data with the longitude/latitude data from the Tobin database. These data were subsequently merged back into the coastal database.

Table 2-1 shows the classification of wells completed since 1980 that were active as of September 1991 and their location as a result of the mapping efforts in Louisiana and Texas. Note that the onshore and unknown wells are, for the most part, also coastal, since most of the polygon is within the Chapman Line, a line that was specified in the July 21, 1982, *Federal Register* (47 FR 31554) as defining the coastal subcategory in Louisiana and Texas regardless of whether a well was located in a body of water (see Section Three for more details).

Following the mapping effort, and just before the Coastal Oil and Gas Questionnaire was sent to coastal operators, data on current ownership was purchased from the Louisiana DNR and Texas RRC (Louisiana DNR, 1993; Texas Railroad Commission, 1993). These new data were merged into the existing database, using the 10-digit API number, to identify any changes in ownership and addresses of operators. Seventy wells were identified at this time as onshore and not within the Chapman region and were dropped from the data set. The final result was a list of 354 operators and 2,640 wells in the Gulf of Mexico coastal region.

2.3 THE COASTAL OIL AND GAS QUESTIONNAIRE

As part of effluent limitations guidelines and standards development, EPA conducted a data collection effort for the coastal oil and gas industry—the 1993 Coastal Oil and Gas Questionnaire. The Questionnaire was conducted under the authority of Section 308 of the Clean Water Act (the federal Water Pollution Control Act, 33 USC Section 1318). It was used to collect technical and economic information for use in developing the proposed effluent guidelines for the coastal oil and gas industry. As discussed above, operators were identified based on whether they operated wells identified as coastal subcategory wells.

EPA wanted up-to-date, accurate data to develop sound regulations, including information about waste stream generation, treatment, and disposal; the costs of treatment and disposal; and the financial status of the firms in the industry. Because of the varied data

TABLE 2-1

PRESURVEY ESTIMATE OF NUMBER OF COASTAL WELLS BY LOCATION

Location	State		Total
	Louisiana	Texas	
Inland bay/harbor	469	182	651
Estuarine	682	95	777
Lacustrine (in lakes)	27	7	34
Marine (wetland)	1	1	2
Onshore (Chapman)	193	408	601
Palustrine (freshwater wetland)	183	37	220
Riverine	38	0	38
Unknown (assumed coastal Chapman for survey purposes)	387	0	387
Total	1,980	730	2,710

Source: ERG estimates.

required, the survey was designed to collect some information at the company level and collect technical information at both the well level and treatment facility level. This task involved conducting a census of the companies identified as operating wells in the coastal subcategory and sampling the wells operated by these companies. Financial and some basic technical information was required from each company; technical information on sampled wells and their respective treatment facilities also was collected independently. Whereas some companies were required to submit information on from one to many wells, others were not required to report on any wells they operated in the coastal subcategory.

EPA identified 361 operators of oil and gas wells in the coastal subcategory—354 operators in south Louisiana and east Texas (see Section 2.2.), and 7 operators in Cook Inlet and North Slope, Alaska. EPA identified a population of 3,623 coastal subcategory oil and gas wells (2,640 Gulf of Mexico region wells and 983 Cook Inlet and North Slope wells). EPA stratified the wells in the coastal subcategory by four factors:

A. Geographical location (Alaska or Gulf of Mexico)

B. Operator type (major, small independent, other)

C. Completion date (before 1990 or during/after 1990)

D. Water type (fresh or saline)

This population was then divided into three subpopulations. By dividing the wells into subpopulations, EPA was able to conduct a census of wells within some categories and sample wells in others. EPA conducted a census of all wells that were controlled by small operators (i.e., operators with only one well in the coastal subcategory) and all wells on multiwell structures, then sampled other wells in the population. The three subpopulations are:

A. Pretest—all 327 wells operated by 6 firms were enumerated in the pretest.

B. Census—179 wells were surveyed because either they were the only coastal wells operated by individual firms or they were identified as potentially a part of a multiwell platform.

C. Sample—the remaining 3,117 wells were used as a sampling frame for selecting a stratified random sample of 438 wells to be included in the questionnaire.

Survey results throughout the EIA are weighted according to the sampling plan. Wells sampled from the third subpopulation received a weight equivalent to the ratio of total wells in an individual stratum to wells sampled from that stratum, while wells in the census received a weight of 1. Since all companies were surveyed, companies received a weight of one.

Overall, EPA conducted a census of the 361 companies identified as operating wells in the coastal subcategory and surveyed 617 of the 3,296 wells remaining after pretest for the questionnaire. For the regulatory proposal, EPA had results from 236 companies and 473 wells. The current status of the respondent companies is shown in Table 2-2 (SAIC, 1994).

As noted previously, one group of wells in Louisiana and Texas, the "pre-1980" wells, was not captured in the Section 308 survey. Throughout the remainder of this EIA, results for the Gulf of Mexico are extrapolated to this missing group as outlined in Section 3.3.3.1.

2.4 REFERENCES

Avanti Corporation. 1991. Delineation of the Baseline of Selected Coastal States. August 22.

Eastern Research Group, Inc. (ERG). 1992. Memorandum from Eric Sigler, ERG, to Ann Watkins and Joe Ford, EPA. Status Update on Coastal Data Base. March 31.

Eastern Research Group, Inc. (ERG). 1994. Memorandum from Maureen Kaplan, ERG, to Neil Patel, EPA. Stand-Alone Projects: ERG Multiwell Structures and Single-Well Structures in the Section 308 Data. February 11.

Louisiana DNR. 1993. Well File and Operator Address File. Received by ERG from Louisiana DNR, transmittal dated June 6, 1993.

SAIC. 1994. Draft Report: Estimation Procedures for the Coastal Oil and Gas Questionnaire. April 12.

Texas RRC. 1993. Well Bore Data Base Tape, P-4 Certificate of Authorization Tape, and P-5 Organization Report Tape. Received by ERG from Texas RRC, transmittal dated June 8, 1993.

TABLE 2-2

STATUS OF THE QUESTIONNAIRE RESPONSE

Status of Questionnaire	Count
Company has data included in database	236
Company is out of scope (i.e., out of business, not a coastal operator, never delivered, duplicate copy sent to the same company as another survey)	95
Company will have data included in the database for the next round of data analysis	18
Company is being contacted by EPA's Office of Enforcement	12
Total	361

Source: ERG estimates.

SECTION THREE

INDUSTRY PROFILE

3.1 INTRODUCTION

The effluent limitations and guidelines for coastal oil and gas operations will affect only a small portion of the overall U.S. oil and gas industry. For this subcategory of the industry, 40 CFR Part 435 defines "coastal" as "(1) any body of water landward of the territorial seas as defined in 40 CFR Part 125.1(gg) [subsequently revised], or (2) any wetlands adjacent to such waters." According to this definition, any well located in waters of the United States, or any wetlands adjacent to a waterbody subcategory, is considered a coastal subcategory well. Most of the activity in the coastal subcategory, however, is concentrated in and around the Gulf of Mexico (i.e., the coasts of Alabama, Florida, Louisiana, and Texas); Long Beach, California; and Cook Inlet and the North Slope of Alaska. Industry activity also was investigated in Mississippi and the Mid-Atlantic region (i.e., along the coasts of Maryland and Virginia).

Investigations conducted as part of the EIA development process indicated that areas beyond Gulf coastal Louisiana and Texas and Cook Inlet, Alaska, will not be significantly affected by the proposed guidelines. These investigations included assessment of current industry activities and practices in these regions as well as review of state regulations concerning the discharge of wastes from oil and gas operations. Determinations about a region with coastal subcategory activity that would not be affected by the guidelines are based on the following findings (summarized in Table 3-1):

- **Coastal Alabama.** About 15 wells are thought to be operating in this area. As of May 25, 1994, however, when this region was designated part of the National Pollutant Discharge Elimination System (NPDES), the discharge of drilling fluids and cuttings has been prohibited. Also, a state law requires that produced fluids be injected (ERG, 1993a; U.S. EPA, 1994a).

- **Coastal Florida.** About 41 producing wells in this region could be considered coastal operations and about 2 additional wells are drilled each year. Nonetheless, all operators inject their produced water; reuse their drilling fluids or

TABLE 3-1

STATUS OF COASTAL REGIONS OUTSIDE TEXAS, LOUISIANA, AND COOK INLET

Location	Number of Producing Wells	Annual Drilling Activity	% Produced Water Injected	% Drilling Waste Landfarmed or Injected
Mid-Atlantic coast	0	0	NA	NA
Alabama	15	3-5	100%	100%
Florida	41	2	100%	100%
Mississippi	0	0	NA	NA
California	586	6-7	100%	100%
North Slope	2,085	106	100%	100%

NA = Not applicable.
Source: U.S. EPA, 1994a,b; ERG, 1993a.

either inject them annually or leave them in a dry wellbore; and either dispose of cuttings in reserve pits or haul them off site to a landfill (U.S. EPA, 1994a).

- **Coastal Mississippi.** None of the wells operating in Mississippi meet the definition of coastal operations, and all well operators are required by state law to inject their produced water (ERG, 1993a). No new wells are slated to be drilled in the coastal region for the foreseeable future (U.S. EPA, 1994a).

- **Long Beach, California.** Oil and gas production in this area is restricted to four manmade islands in San Pedro Bay (U.S. EPA, 1994a). As of 1993, 586 wells were operated in this area, and six to seven new wells were being drilled each year. All produced water is injected, primarily for waterflooding (see Section 3.2), and no drilling fluids or cuttings are being discharged.

- **North Slope, Alaska.** About 2,085 producing wells are operating on Alaska's North Slope, and about 106 additional wells are drilled annually. No drilling or production waste is discharged in this area (U.S. EPA, 1994b).

- **The Mid-Atlantic Coastal Subcategory.** Currently no oil and gas production or drilling operations are being carried out in this region. Moreover, it is unlikely that any such activity will be initiated within the next 15 years. Should any activity commence, it is unlikely that operators would be allowed to discharge wastes, according to state officials (ERG, 1994a).

The area in the Gulf of Mexico that will be affected by this rulemaking includes coastal Louisiana and Texas as shown in Figure 3-1. In response to litigation concerning the definition of coastal, EPA further explained the definition in a Suspension of Regulation, 47 FR 31554 (July 21, 1982). In that notice, EPA designated the Chapman Line. This line was established as a series of latitudes and longitudes spanning the southern coast of Louisiana and the east coast of Texas (see Figure 3-1). Thus, the Gulf of Mexico coastal region in Louisiana and Texas is bounded by the territorial seas (the "baseline," as discussed in Section Two) and the Chapman Line. The remainder of this EIA refers only to the Texas and Louisiana coastal regions as the Gulf of Mexico region (although Alabama, Mississippi, and Florida are part of the Gulf region, these states are excluded from the remainder of the analysis).

Also of concern is Cook Inlet, near Anchorage, Alaska, and the Kenai peninsula (see Figure 3-2). This area and the Texas/Louisiana portion of the Gulf of Mexico are profiled in this section of the EIA. The profiles cover wells, treatment facilities, and the firms operating in these two areas. Section 3.2 presents a brief description of the process of oil and gas extraction,

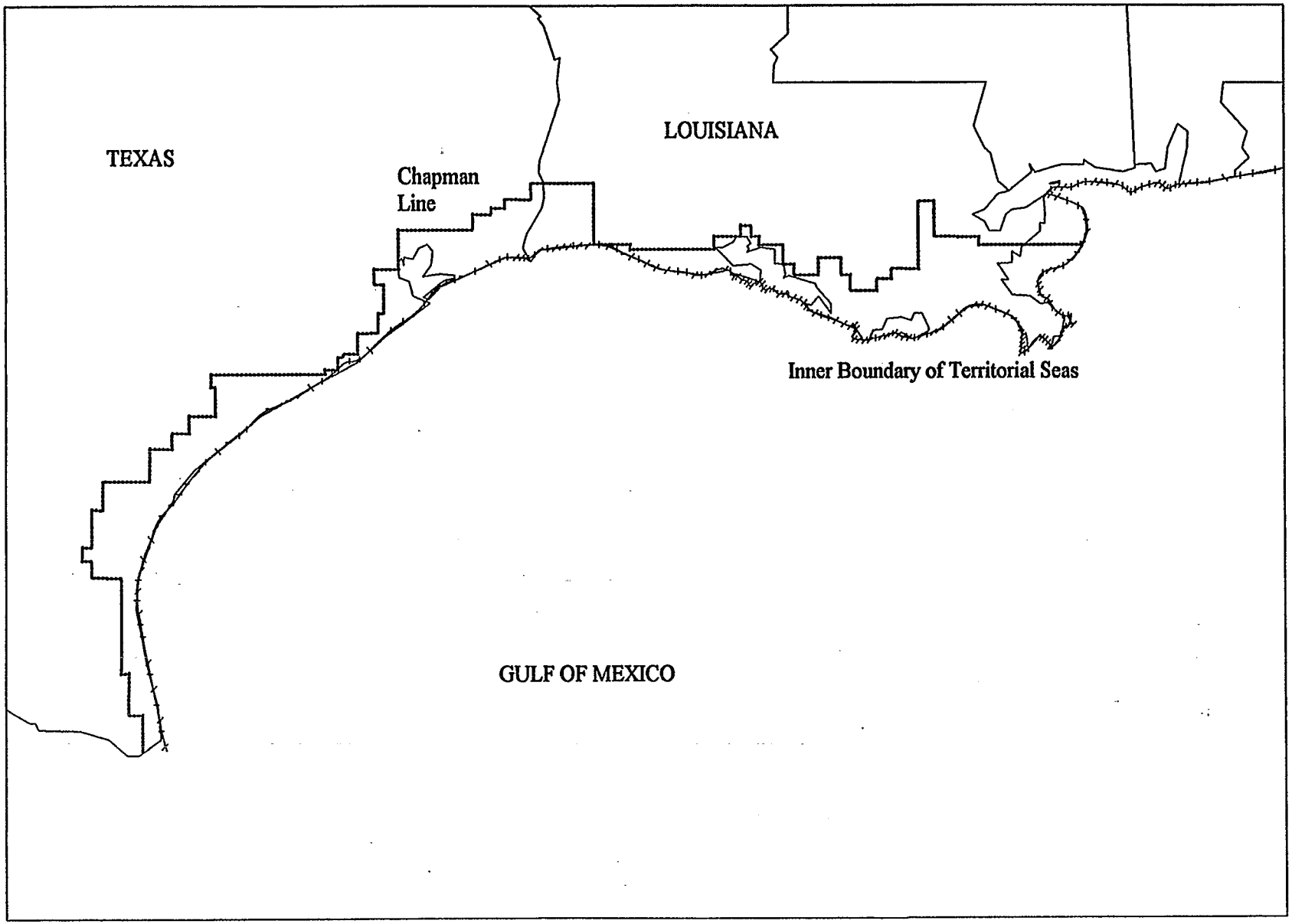

Figure 3-1. Location of the Gulf of Mexico coastal region in Texas and Louisiana.

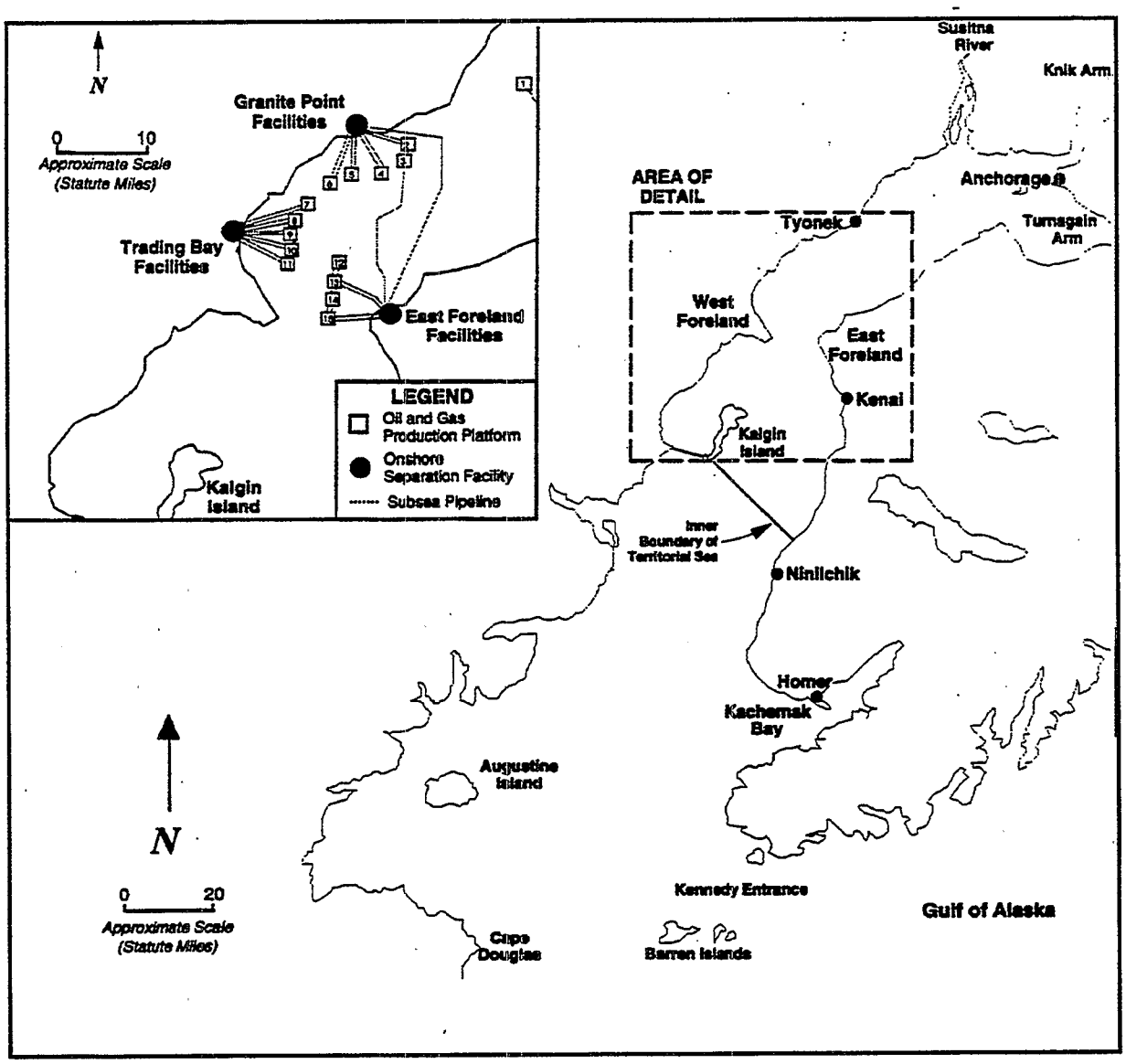

Figure 3-2. Map of Cook Inlet region.

including how wells are drilled, how oil and gas is produced, and what wastes are generated during these processes. Section 3.3 presents a general overview of the industry in the two key regions. First, Section 3.3.1 compares the affected coastal industry to the overall U.S. oil and gas industry. Section 3.3.2 follows with a discussion of trends likely to affect the coastal oil and gas industry. Section 3.3.3 discusses the characteristics of the wells and platforms in the Gulf of Mexico and Cook Inlet and describes the types and nature of the firms owning and operating coastal oil and gas production wells and facilities in these key coastal regions.

3.2 THE PROCESS OF OIL AND GAS EXTRACTION AND THE WASTES GENERATED

Two activities in the oil and gas extraction process generate the major portion of wastes in this industry: drilling activities and production activities. These activities and the related wastes are discussed in this section. The miscellaneous wastes, which are small volume wastes associated indirectly with drilling or production operations, also are discussed. The major source for the information in this discussion is U.S. EPA's Development Document for this rulemaking (U.S. EPA, 1995).

3.2.1 Drilling Operations

The drilling operations of particular concern in this analysis are those performed in Cook Inlet, Alaska. Currently all other drilling activities in the coastal subcategory do not discharge drilling fluids and cuttings, either because of state or federal requirements or operator preference.

The two 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.

In the initial phases of exploration, shallow 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. Exploration activities are usually of short duration, involve a small number of wells, and are conducted from mobile drilling rigs.

In Cook Inlet, exploratory drilling is typically 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. Some exploratory drilling has been performed in recent years in Cook Inlet as part of ARCO's Sunfish field exploration (OGJ, 1994a).

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.

Two commonly used types of drilling rigs for development drilling are the platform rig and the mobile drilling units. In Cook Inlet, development wells often are 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. The last platform to be constructed in Cook Inlet was built in the mid-1980s (Marathon/UNOCAL, 1994). Even with the recent exploratory drilling in Sunfish, no additional construction of platforms is anticipated (personal communication between Allison Wiedeman, EPA, and Jim Short, ARCO, May 9, 1994).

Rotary drilling is used in Cook Inlet. This method uses a rotating drill bit attached to the end of a drill pipe, referred to as the "drill string." With this method, as the wellbore deepens, the walls of the hole tend to cave in and widen; thus, periodically the drill string must be lifted out so that a casing, which is a tube-shaped liner, can be placed in the hole. Cement 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.

Rotary drilling relies on circulating drilling fluid to move drill cuttings (bits of rock) away from the bit and out of the borehole. The drilling fluid, or mud, is a mixture of water, special clays, and certain minerals and chemicals that is pumped "downhole" through the drill string and 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 that 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. At the 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 shaleshakers, desilters, desanders, and centrifuges (each removing sequentially smaller waste particles from the drilling fluid). Some of the drilling fluid remains with the cuttings after solids separation (Ray, 1979; Meek and Ray, 1980). In Cook Inlet, if the cuttings, silt, sand, and residual drilling fluid do not contain free oil or other regulated contaminants, they are discharged into the Inlet.

Drilling fluid also can become contaminated, and thus, constitute a waste, during several different stages of the drilling process. Additionally, drilling fluid can become waste if it cannot be adjusted to provide the appropriate lubrication (lubricity) for drilling at different formation pressures (which vary at different depths). When a drilling fluid no longer meets the requirements for lubricity, density, viscosity, or gel strength, for example, a "mud changeover" must be 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.

Similarly, 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. The more recently developed solids

control systems are much more efficient than in the past; thus, waste drilling fluid stemming from the need to displace fluid that has become overloaded with solids is now less of a problem.

Most drilling fluid systems are water based. Although oil-based systems are less common than they once were, some use of oil (or synthetic) additives is still necessary under special circumstances, such as when performing directional drilling or when freeing a stuck pipe. Thus, some portion of the drilling fluids used in Cook Inlet might not meet a more stringent toxicity limit due to the occasional use of specialized fluids.

The most significant waste streams in Cook Inlet, in terms of volume and particular constituents associated with drilling activities, are drilling fluids and drill cuttings. Drill cuttings are generated throughout the drilling project, although higher quantities of cuttings are generated 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 of the drilling fluid can be recovered after completion of the drilling, either at the rig or by the supplier of the drilling fluid. When drilling is continuous, which can be the case on the multiwell Cook Inlet platforms, drilling fluid can be reused to drill the next well in a series.

A much smaller waste stream associated with the drilling process is drainage from deck platforms during drilling, which can occur during rainstorms. In Cook Inlet, deck drainage is combined with produced water (SAIC, 1994a).

3.2.2 Production Activities

Following the drilling process (in either the Gulf or Cook Inlet), the wells can begin to produce reservoir fluids that consist of oil, natural gas liquids or condensate, and salt water (sometimes dry gas is also produced). The salt water contains dissolved and suspended solids, hydrocarbons, and metals and might contain small amounts of radionuclides. Portions of the salt

water also can include enhanced oil recovery (EOR) fluids, which are gases or liquids injected "downhole" to produce additional reservoir pressure. As hydrocarbons are produced, the natural pressure in the reservoir decreases and additional pressure must be added to the reservoir to continue production of the fluids. When a liquid is used, the process is called waterflooding.

EOR processes are divided into three general classes: thermal, chemical, and miscible displacement. In the thermal process, generally steam is used to aid in removing hydrocarbons form the geological formation. Chemical EOR processes use surfactants, polymers, and/or caustics for washing oil from the formation and driving or displacing oil into the wellbore. In miscible displacement, first kerosene or gas then water are used to dissolve then drive oil from the formation. Typically EOR fluids are a part of the produced water stream.

As they surface, the gas and oil (including EOR fluids) are separated for further processing and sale. Typically a series of vessels are used for the separation process. The major waste streams associated with this process are produced water and, to a much lesser extent, produced sand, which is, in part, made up of fine particles that are entrained with the oil and produced water. More details on the equipment and processes used to separate and treat produced water in both the Gulf and Cook Inlet are presented in Section 3.3.3.

3.2.3 Miscellaneous Wastes

Other wastes besides the drilling and produced water wastes discussed above also can be generated during the productive life of a well. The most common miscellaneous wastes are known as treatment, workover, and completion (TWC) fluids. Small volumes of production deck drainage and domestic and sanitary wastes might also be generated. Deck drainage is generated only if a platform is present. Sanitary and domestic wastes are generated only if toilet or washup facilities are present onsite. Produced sand and deck drainage associated with drilling were discussed above. This section therefore focuses on the processes that generate the major portion of miscellaneous waste—treatment, workover, and completion processes.

Treatment. Well treatment is the process of stimulating a producing well to improve oil or gas productivity. Two basic methods of well treatment include hydraulic fracturing and acid treatment. Hydraulic fracturing is typically used on sandstone, and acid treatment is generally performed on formations of limestone or dolomite (Walk, Haydel and Associates, undated; Wilkins, 1977). Hydraulic fracturing, in which a fluid is pumped into the formation under high pressure, relies on inert materials known as proppants (e.g., sand, walnut shells, aluminum spheres, glass beads) that remain in the formation to prop the channels open after the fluid and pressure have been removed (Walk, Haydel and Associates, undated; U.S. EPA, 1987). This method of well treatment is rarely used in the Gulf of Mexico.

Acid stimulation involves injecting acid solutions into the geological formation. The two types of acid treatment used are acid fracturing and matrix acidizing. In acid fracturing, the acid solution is injected under high pressure. The acid solution both dissolves the formation rock and fractures it. Matrix acidizing uses low pressures to avoid fracturing. Other chemical treatments sometimes used include treatment with organic solvents, such as xylene or toluene, to remove paraffins or asphalts that block the wellbore.

Not all residuals from these well treatments become wastes. Many are recycled to be used in other well treatment fluids. Nonetheless, some become part of the produced water stream and are subsequently discharged (such as in Cook Inlet) or injected with produced water, and some are disposed of separately from produced water.

Workover. Waste fluids can also be generated when a well undergoes a workover to improve or restore productivity, repair or replace downhole equipment, evaluate the rock formation, or abandon a well. Workovers are generally performed every 3 to 5 years (API, 1988, 1991). Responses to EPA's Section 308 survey indicate, however, that workovers in the Gulf of Mexico occur once per year on average (SAIC, 1994b). Workovers generate some of same wastes as those generated during well treatment and completion operations since some of the operations are the same (e.g., stimulation, reperforation, casing repair, replacement of subsurface equipment) (Walk, Haydel and Associates, undated; Acosta, 1981; API, 1988).

Completion. Completion operations include the setting and cementing of the production casing, packing the well, and installing the production tubing. All completion methods consist of four steps: wellbore flush, production tubing installation, casing perforation, and wellhead installation.

The initial wellbore flush involves injecting a slug of fluids into the casing. These cleaning or preflush fluids can be circulated and filtered many times to remove solids from the well and to minimize potential damage to the geological formation (U.S. EPA, 1992). Once the well has been cleaned, a second completion fluid (i.e., a "weighting fluid") is injected. This fluid maintains sufficient pressure to prevent the formation fluids from migrating into the hole before well completion is finished.

Next, production tubing is installed inside the casing using a packer, which is placed at or near the end of the tubing. The packer consists of pipe, gripping elements, and sealing elements. When the tubing is in place, completion fluids are trapped between the casing and the production tubing by the packer. These fluids, known as "packer fluids," provide long-term protection against corrosion. Typically packer fluids are mixtures of a polymer viscosifier, a corrosion inhibitor, and a high concentration salt solution (Gray, Darley, and Rogers, 1980). These fluids can be removed during workover operations (Arctic Laboratories et al., 1983).

Following installation, the production tubing is perforated to allow hydrocarbons to flow from the reservoir into the wellbore. For this step, a special gun is used to fire bullets or charges that penetrate the casing and cement. Alternatively, a small perforated pipe can be hung from the bottom of the casing (Baker, 1985; Radian Corp., 1977).

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

3.3 GENERAL OVERVIEW OF THE AFFECTED COASTAL SUBCATEGORY INDUSTRY

3.3.1 The Affected Coastal Subcategory Industry Compared to the U.S. Oil and Gas Industry

The coastal subcategory is a small fraction of the overall U.S. oil and gas industry. Since much of the subcategory is already achieving zero discharge, the portion of the coastal subcategory that will be affected by the effluent guidelines is an even smaller fraction. Table 3-2 presents information on production, number of establishments, and number of wells in the affected coastal subcategory industry as a portion of the U.S. oil and gas industry. The estimates specific to the Gulf (Texas and Louisiana only) in this table are derived from the Section 308 survey and adjusted for wells that were completed prior to 1980 (see Section Two). Thus, the number of wells shown here are greater than the number in the Section 308 survey universe (see Section 3.3.3 for a discussion of how the number of "pre-1980" wells was estimated). As the table shows, the affected portion of the coastal subcategory is estimated to produce (in 1992) 56.4 million barrels (bbls) of oil and 782.4 Mcf (million cubic feet) of gas, which is only 2.1 percent of total U.S. oil production and 3.5 percent of U.S. total gas production. Oil production from this subcategory alone is equivalent to only 2.5 percent of total foreign oil imports.

The value of annual oil and gas production in the affected coastal subcategory (i.e., the Louisiana/Texas portion of the Gulf and Cook Inlet) is estimated to be $1,891.1 million (1992), which is 2.5 percent of the value of total U.S. production. The affected portion of the subcategory is estimated to employ 6,167 employees, or 3.4 percent of the total U.S. oil and gas production workforce. The number of establishments (firms) is estimated at 440, which is 3.4 to 6.0 percent of the numbers of establishments in the comparable portion of the U.S. industry (see footnote to Table 3-1). The total number of wells in the affected portion of the industry is estimated to be 4,912, which is 0.6 percent of the total number of producing wells in the United States. A more detailed analysis of wells, treatment facilities, and firms in the affected coastal region is discussed in Section 3.3.3.

TABLE 3-2

INDUSTRY PROFILE OF AFFECTED SEGMENT OF THE COASTAL SUBCATEGORY: GULF COASTAL (LOUISIANA AND TEXAS ONLY) AND COOK INLET VS. TOTAL U.S. INDUSTRY

	Oil Production	Gas Production	Value of Production ($ million 1992)	Number of Employees	Number of Establishments	Number of Wells
Coastal Subcategory — Gulf of Mexico (1992) — Cook Inlet (1992)	56.4 million bbls 42.8 million bbls 13.6 million bbls	782.4 million Mcf 653.7 million Mcf 128.7 million Mcf	$2,229.3 $1,891.1 $338.2	6,197 5,403 794	440 operators 435 operators 5 operators	4,912 4,675 237
Total U.S. industry (1992)	2,624.6 million bbls	18,522.7 million Mcf	$74,510.2	180,700	7,281-13,086 establishments*	871,176
Total imports (1992)	2,222.7 million bbls	—	$38,662.5	—	—	—
Coastal industry as percentage of total U.S. industry	2.1%	4.2%	2.5%	3.4%	3.4-6.0%	0.6%
Total coastal production as percentage of total imports	2.5%	—	4.9%	—	—	—

*U.S. Bureau of the Census, 1991. The count is presented as a range because it includes establishments in SIC 131, Crude Petroleum and Natural Gas, as well as SIC 1389, Oil Field Services, Not Elsewhere Classified (5,805). This latter category is included because some of the Section 308 respondents were discovered to be operators only (i.e., they operate wells for owners, but do not own the wells). These operators would most likely be classified in SIC 1389. Note also that some of the Section 308 survey respondents that would be considered a separate establishment as reported by the Census Bureau were dropped from the Section 308 survey (and reported as duplicates) because they had the same firm-level data as another operator and thus the two are considered the same firm. The number of duplicates totaled 23.

Source: ERG estimates based on Section 308 survey results, API (1994), and AOGA (1993).

3.3.2 Trends in the Affected Coastal Subcategory

Because the Section 308 survey did not collect more than 1 year's data, trends exclusive to the affected coastal subcategory could not be described. Nonetheless, the trends of greatest concern—the rate at which production is expected to decline with time and the expected track of the wellhead price of oil—can be expected to follow general industry trends to some extent.

These two trends are central to several important assumptions used in this economic analysis. Assumptions about the rate of decline of oil production can vastly change the outcome of analyses that predict the economic viability of a well or platform, as can assumptions about the price of oil or gas. The economic life of a well or platform will be lengthened as decline rates fall or as prices rise; conversely, the economic life will be shortened as decline rates rise or as prices fall.

Data on the rate of decline of oil production at individual wells are available, both for Gulf of Mexico and for Cook Inlet wells. An analysis of data used to determine the location of wells in the Gulf coastal region (see Section Two), for instance, indicates that Gulf of Mexico well production tends to decline at a rate of 12 to 15 percent per year (ERG, 1992). Information provided by Cook Inlet operators (Marathon/UNOCAL, 1994) indicates that the typical decline rate for wells in that area is about 8 percent per year. The economic model of the Cook Inlet platforms (discussed in Section Five) is used to generate the expected lifetime production (i.e., the total amount of hydrocarbons that can be produced given the economic profile of the platform, such as costs of production, price of oil, etc.) in Cook Inlet based on this decline rate and the number of wells and recompletions expected to be undertaken in the Inlet. This expected total lifetime production of all platforms is estimated to be 198.1 million barrels of oil equivalent (BOE)[1] with a net present value of $417.2 million.

For the Gulf of Mexico, the economic model is not used to determine lifetime production for the entire region. Rather, a decline rate is factored into current levels of production to

[1]To compute barrels of oil equivalent, a volume of gas is converted to an equivalent barrel of oil on the basis of Btu content, then added to oil production.

compute a lifetime production estimate, which is a more simplistic approach than that used for the analysis of Cook Inlet. Use of a 12 to 15 percent decline rate associated with individuals wells, however, will overstate declines for a region, since wells are constantly being drilled to replace or augment current production.

According to recent projections (OGJ, 1994b), overall production will be declining in the United States at a rate of about 3 percent per year from 1993 to 2000. Given that the Gulf of Mexico coastal area in Louisiana and Texas is a mature area, production in this region could be declining at a higher rate than the overall U.S. rate. Nonetheless, the two decline rates, the 3 percent national estimate and the 15 percent well-specific estimate, can be used to bound the estimate of the decline rate in the Gulf of Mexico. A 30-year horizon was used to compute lifetime production in the Gulf (if declines are closer to 3 percent per year, however, a 30-year horizon might be somewhat short and could understate lifetime production). Lifetime production can be computed in a manner similar to computing the net present value of a stream of income. Based on the assumption that oil today is worth more than oil tomorrow (as a dollar today is worth more than a dollar tomorrow), the net present "value" in terms of BOE was calculated using the present (1992) estimated production of 159.2 million BOE and both the high and low estimate of potential decline over the 30-year horizon. This calculation results in a total lifetime production estimate for the Gulf of Mexico ranging from 692.5 million BOE to 1,391.2 million BOE.[2]

With production declines, the revenues, employment, and other indicators of an industry's vitality also will tend to decline, although the number of firms operating in the Gulf of Mexico might not decline for a while. The largest well owners in the region, large independents and integrated oil companies ("majors"—see Section 3.3.3.3), are leaving the region because other investments (primarily foreign) are proving more profitable. Thus, they are selling their properties to local owners, who tend to be small and own just a few wells. Indeed, many (about 40 percent) of the operators in the Gulf of Mexico own only one coastal well completed after

[2]Since the model presents lifetime production in this present value manner, it was necessary to use the same approach for comparison purposes. Using either this present value approach or a straight additive volume approach will produce the same results, proportionately, in the analysis.

1980 (although they might own other onshore properties and pre-1980 wells) (ERG, 1993b). Thus, the trend in the Gulf coastal region is one toward a less highly concentrated industry[3] with many very small firms (nearly 40 percent of the Gulf operators employ only 0 to 9 employees; see Section Nine).

The price of oil has been assumed to be constant in this EIA. This assumption is consistent with current forecasts of oil prices (OGJ, 1994c), which indicate that oil prices are rising at about the same pace as inflation (i.e., the real price of oil is not expected to increase through the rest of this decade). Forecasts, however, cannot anticipate major oil shocks, and taking into account such exogenous factors is beyond the scope of this analysis. In general, if oil prices increase substantially, regulatory impacts will tend to become proportionately smaller. Conversely, if oil prices decrease substantially, impacts could become proportionately larger, although baseline well shut-ins and firm failures could substantially alter the entire analysis.

3.3.3 Detailed Discussion of Wells, Facilities, and Firms

3.3.3.1 Wells and Platforms in the Coastal Region

According to estimates from the Section 308 survey, there are currently 2,548 producing Gulf coastal wells in coastal Texas and Louisiana (not all wells in the original survey universe of 2,640 wells—see Section Two—were found to have been productive in 1992). As discussed in Section Two, however, the survey universe of Gulf coastal wells did not include wells completed prior to 1980 or wells within a few very small sections of the Louisiana/Texas coastal region as defined by the Chapman Line (see Figure 3-1). Figure 3-3 shows the area—"the polygon"—for which well information was purchased from Tobin Surveys, Inc., in relation to the Chapman Line (see Section Two). Further analyses were performed to determine the number of pre-1980/other wells estimated to be currently producing. Two approaches were undertaken. In the first case only the pre-1980 wells could be addressed (ERG, 1992). In this approach, the number of total

[3]A less highly concentrated industry is an industry in which many firms have a very small market share, in comparison to a highly concentrated industry where very few firms have the major portion of the market share.

wells ever drilled in the polygon (see Figure 3-3) is known and the survival rates of productive wells from 1980 to 1990 are also known. Based on the total number of pre-1980 wells in the polygon estimated to have been productive at some time (26,861 wells) and a decline rate developed as an exponential function (ERG, 1992), the total number of estimated pre-1980 wells could be determined. The decline rate equation leads to an estimate of a survival rate of 9.67 percent for all pre-1980 wells (i.e., 9.67 percent of ever-productive pre-1980 wells are estimated to be currently productive). Applied to the total number of one-time productive pre-1980 wells, an estimate of 2,597 currently productive pre-1980 wells is derived. This approach would miss both pre-1980 and newer Chapman wells not captured in the polygon, although it could include noncoastal pre-1980 wells in areas of the polygon not within the Chapman Line.

The second approach uses the number of known discharging treatment facilities (see Section 3.5 below) combined with the number of discharging treatment facilities that were estimated using the Section 308 survey. The number of discharging facilities estimated using survey data is 202 facilities. Known permitted facilities in 1992 total 325. Thus, a little over a third of discharging facilities were not captured in the survey. The average number of wells as reported in the Section 308 survey served by discharging facilities (7.35 wells per facility) was used to calculate the total number of discharging wells (7.35 x 325 facilities = 2,389 wells). It was also assumed that nondischarging facilities were missed by the survey in the same proportions as discharging facilities since no information to the contrary is known; thus, the 328 nondischarging facilities estimated using the survey were extrapolated to 528 facilities. According to the survey, nondischarging facilities serve 4.33 wells; thus, the total number of nondischarging wells is estimated to be 2,286, for a total of 4,675 coastal wells (2,389 discharging wells plus 2,286 nondischarging wells). The difference between the estimated number of wells in the survey (2,548) and the 4,675 estimated as above should be the number of pre-1980 wells and wells that were missed within the Chapman Line. This estimate is 2,127 wells (of which most are considered likely to be pre-1980 wells). The predicted number of wells using the decline rate compares reasonably well to the number of wells estimated using the second approach.

The total number of Louisiana/Texas Gulf coastal wells is, thus, estimated to be 4,675. This number is used as the 1996 baseline according to the assumption that approximately the same number of wells will go into as out of service between 1992 and 1996. A total of 686 wells

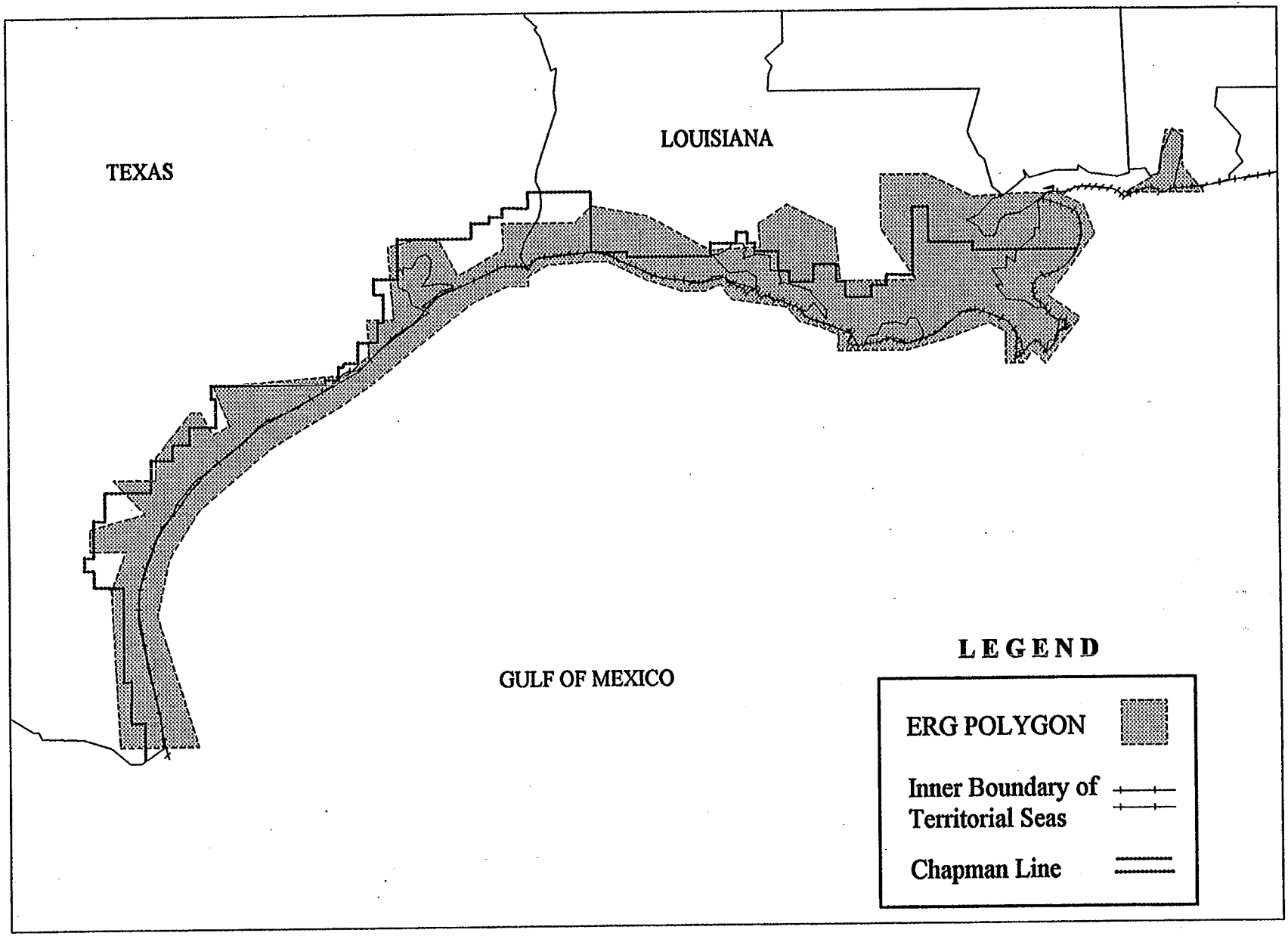

Figure 3-3. Overlap of ERG Polygon and the Gulf of Mexico coastal region.

drilled per year is estimated based on the Section 308 survey. (This estimate was not adjusted because the majority of the "missed" wells are thought to be pre-1980 wells and, thus, the "missed" discharging facilities might be serving pre-1980 wells predominantly. Therefore, this "missed" group is not likely to be associated with much drilling activity.)

Consequently, in 1992, based on an estimated 2,389 discharging wells and a total estimated population of 4,675 coastal wells in the Gulf of Mexico region, 51 percent of Gulf of Mexico wells are estimated to have been discharging. In 1996 this proportion will be considerably less. According to Section 308 survey results,[4] when facilities that are predicted to cease discharging in 1996 are considered, only 1,588 productive wells (approximately 34 percent of Gulf of Mexico coastal wells estimated to be productive in 1992) will be continuing to discharge. See Section Five for a detailed discussion of how this estimate of 1,588 discharging wells was determined.

The typical Gulf of Mexico well produces both oil and gas. A total of 7 percent of Gulf coastal wells are gas only, 9 percent are oil only, and 84 percent produce both oil and gas (SAIC, 1994c). The average gas-only well produces 970 cubic feet of gas per day, while the average oil-only well produces 16 barrels per day (bpd) of oil and the average gas and oil well produces 484 cubic feet of gas per day and 36 bpd of oil (SAIC, 1994d). Total production in the Gulf of Mexico is estimated to be 42.8 million bbls of oil and 653.7 Mcf of gas, or 159.2 million BOE annually (1992).[5]

Unlike the offshore subcategory for Cook Inlet, few Gulf of Mexico region wells are located on multiwell platforms. The few multiwell platforms operating in the Gulf coastal area

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[4]These results required additional adjustments for pre-1980 wells that are discussed in detail in Section Five. These additional adjustments stem from the fact that the facilities that continue discharging might disproportionately serve pre-1980 wells.

[5]This estimate includes the 1.61 factor for pre-1980/other wells. Note that this approach might overstate total production because pre-1980 wells probably produce less on average per day than wells drilled after 1980. Due to lack of data, however, it is assumed that production is similar. If production levels are actually much less from these wells when the regulation is promulgated than the survey wells, the number of wells estimated to be shut in immediately might increase, but the proportion of total production lost would be reduced.

appear to have less than four wells on them (ERG, 1994b). Thus, the key unit of analysis in the Gulf of Mexico for determining production loss and economic life is the well. As discussed below, when multiwell platforms are the rule, the platform becomes the key unit of analysis. Given the typical single-well nature of the Gulf of Mexico region, well-based parameters are used to model the economic viability of Gulf oil and gas production activities but the platform is the key unit of analysis for Cook Inlet (see Section Five for key parameters for both Gulf wells and Cook Inlet platforms).

Platforms in Cook Inlet

There are 15 platforms located in Cook Inlet, Alaska. Two of these platforms are currently shut in (Spark and Spur—both owned by Marathon/UNOCAL), but drilling plans have been developed for one platform (Spark). Thus, 14 platforms are considered operational or potentially operational in Cook Inlet. A total of 237 wells are currently producing on these platforms. Table 3-3 lists the platforms, the number of wells on each platform, and the owner/operator of the platform. As shown, there are 208 oil wells and 29 gas wells in Cook Inlet. Total annual production in 1993 was 12.9 million bbls of oil and 120.5 million Mcf of marketable gas (AOGA, 1993). Total lifetime production (using the production loss model under baseline assumptions—see Section Five) is estimated at 198 million BOE. Over a period of 7 years, a total of 36 new wells are planned to be drilled and 22 recompletions are expected to be performed (see Section Four for a detailed drilling schedule by platform).

A potential area of development in Cook Inlet is the Sunfish Field, which is located in the North Upper Cook Inlet. At this time, the field has not been brought into production, and discussions with industry (personal communication between EPA and ARCO, May 9, 1994) indicate that it is unlikely that a platform will be constructed to develop this field because of disappointing exploration results.

TABLE 3-3

PLATFORMS, OPERATORS, AND WELLS IN COOK INLET

Platform	Operator	No. of Active Oil Wells	No. of Active Gas Wells	Oil Production (bpd)	Gas Production (Mcf)	Discharge Location
King Salmon	UNOCAL	19	1	4,100	Plat. use	Trading Bay
Monopod	UNOCAL	29	0	2,000	Plat. use	Trading Bay
Grayling	UNOCAL	24	2	7,000	Plat. use	Trading Bay
Granite Point	UNOCAL	11	0	4,300	Plat. use	Granite Point
Dillon	UNOCAL	10	0	0	0	Platform
Bruce	UNOCAL	11	0	600	Plat. use	Platform
Anna	UNOCAL	20	0	2,300	Plat. use	Platform
Baker	UNOCAL	11	1	1,000	Plat. use	Platform
Dolly Varden	Marathon	24	1	6,500	Plat. use	Trading Bay
Spark	Marathon	0	0	0	0	Granite Point
Steelhead	Marathon	3	11	1,800	165,000	Trading Bay
Spurr*	Marathon	0*	0*	0	0	Granite Point
SWEPI "A"	Shell Western	22	1	2,700	Plat. use	E. Foreland
SWEPI "C"	Shell Western	24	0	2,400	Plat. use	E. Foreland
Tyonek "A"	Phillips	0	12	0	165,000	Platform

*Spurr is considered completely nonactive in this EIA.

Source: U.S. EPA, 1995; EPA, 1994b.

3.3.3.2 Produced Water Treatment Facilities in the Coastal Region

Facilities in the Gulf of Mexico

A separation, or production, facility consists of the treatment equipment and storage tanks that process the produced fluids. Production facilities can be configured to service one well, or as central facilities that service multiple satellite wells, also known as tank batteries or gathering centers. In 1992, according to permit databases provided by the Louisiana DEQ and the Texas RRC, 325 produced water separation facilities were discharging in the Gulf coastal region (EPA, 1995). Based on compliance schedules set up by Louisiana DEQ, court-ordered requirements, and results of the Section 308 survey (which asked respondents whether they would be discharging in 1996), facilities were removed from the list of dischargers to create a list of facilities expected to be discharging in 1996. A maximum of 216 facilities[6] are expected to be discharging in 1996 (SAIC, 1994e). The total number of nondischarging facilities in the Gulf of Mexico region is estimated to be 528 in 1992.[7] Thus, in 1996, only a little over one-quarter or fewer of the produced water facilities (total 853) in the Gulf coastal region are expected to be discharging, assuming the 109 facilities expected to cease discharging switch to injection or commercial disposal.

Unlike other industries, wastewater generation in the oil and gas industry is not proportionate to the quantity of materials processed. Produced water can constitute from 2 to 98 percent of the fluid production at a given facility. In general, the proportion of hydrocarbons to produced water tends to be high during the initial production phase and decreases as hydrocarbons are depleted. Thus, any regulation affecting the cost of produced water disposal will tend to affect the older, more marginal fields more than the newer developmental projects.

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[6]This total does not account for wells that might shut in for reasons of economics unrelated to the effluent guidelines between now and 1996, causing additional facilities to cease discharging.

[7]This number is derived from the results of the Section 308 survey, adjusted by a factor of 1.61 to account for potentially missing facilities (see discussion above in Section 3.3.3.1).

The average produced water discharge rate from the Gulf of Mexico is 1,923 bpd for facilities that inject produced water and 2,069 bpd for facilities that discharge produced water (SAIC, 1994f). As noted in Section 3.3.3.1, the typical discharging facility serves about seven wells, whereas the typical nondischarging facility serves approximately four wells. This difference might arise because with very low costs of disposal (typical of discharging facilities), marginal wells can be operated economically for a longer period of time, leading to more wells being served per facility at discharging facilities.

Currently, produced water treatment facilities in the Gulf of Mexico are designed to meet best practicable technology (BPT) requirements, which restrict the oil and grease concentrations of produced water to a maximum of 72 mg/L for any one day and to a 30-day average of 48 mg/L. Technologies and practices used to achieve this level of control include:

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

The typical Gulf coast discharging facility uses gravity separators, which are tanks large enough to store oil and water mixtures for a sufficient length of time to allow the mixture to separate. Chemicals might be added to hasten or augment the separation process. At separation facilities where produced water is injected, the produced water is typically filtered prior to injection. Although used in the Gulf, gas flotation is not used widely enough in coastal operations to be considered a typical BPT process. Subsurface injection, however, is more

frequently used in coastal areas, as the number of nondischarging facilities in the Gulf coastal region reflects.

Facilities in Cook Inlet

Three land-based and five platform-based separation/treatment facilities operate in Cook Inlet. About 98 percent of all produced water is treated and discharged from the three land-based facilities (primarily the Trading Bay facility). Produced water is generated at a rate of about 127 thousand barrels per day (U.S. EPA, 1995). One platform and one land-based facility currently use gas flotation (in addition to skim tanks, which is a type of gravity separator). Most other facilities use skim tanks only, or a combination of skim tanks and corrugated separators (Table 3-4).

3.3.3.3 Oil and Gas Firms Operating in the Coastal Region

The expenditures required to comply with the effluent limitations guidelines for the coastal oil and gas industry will be financed by coastal firms and their investors. Before assessing the impact of the effluent guidelines, it is useful to evaluate the current financial condition of these firms, both generally and in comparison with the overall domestic oil and gas industry. The firms in the Gulf of Mexico are discussed first. Information on the corporate structure of the firms involved in oil and gas production in this region is presented and the results of ratio analyses and the relative health of these firms are discussed in terms of profitability, leveraging ability, and other factors. The financial condition of known dischargers is also compared to the financial condition of the coastal operators overall.[8] The same type of financial information is then presented for the Cook Inlet operators.

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[8]Not all dischargers can be identified in the survey because not all wells were surveyed. Only when a discharging well was surveyed can an operator be identified conclusively as a discharger. Names of operators on discharge permits are also not always an identifier because some operators are doing business under several different names and sometimes facilities might have been sold but the permit database has not yet been updated with the new operator name.

TABLE 3-4

PRODUCED WATER TREATMENT FACILITIES IN COOK INLET

Facility Name	Operator	Average Produced Water Volume (bpd)	Discharge Location	Treatment Type
Platform-Based Treatment Facilities				
Dillon	UNOCAL	0*	Platform	Skim tanks
Bruce	UNOCAL	160	Platform	Skim tanks
Anna	UNOCAL	1,500	Platform	Skim tanks
Baker	UNOCAL	30	Platform	Skim tanks
Tyonek "A"	Phillips	170	Platform	Skim tanks, gas flotation
Onshore Treatment Facilities				
Granite Point	UNOCAL	300	Spark platform	Skim tanks
Trading Bay	Marathon	121,243	Outfall	Skim tanks, gas flotation, settling pits
E. Foreland	Shell Western	3,300	Outfall	Skim tanks, corrugated separators

*Dillon was not discharging at the time of EPA's analysis. Recent information indicates it is currently discharging. During 1991, the discharge volume was 2,650 bpd.

Source: U.S. EPA, 1995.

Firms Operating in the Gulf of Mexico

Gulf coastal petroleum producers can be divided into two basic categories. The first consists of the major integrated oil companies. These companies 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 coastal producers are independents. The independents are engaged primarily in exploration, development, and production of oil and gas and are 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 generally produce more oil and gas, earn significantly more revenue and income, have considerably larger assets, and have greater financial resources than the independents. In general, majors are relatively homogeneous in terms of size and corporate structure. All majors are considered large firms under the Regulatory Flexibility Act (RFA) guidelines and all generally are standard corporations (rather than S corporations, limited partnerships, or other alternative structures) (see Section Nine).

Producing companies vary in their range of products. In the early 1980s, due to cash surpluses and diminishing oil reserves, many oil companies, and particularly the majors, diversified into other areas such as mining and development of alternative nonpetroleum energy sources (U.S. EPA, 1993).

Independents can vary greatly by size and corporate structure. Larger firms tend to be corporations; smaller firms tend to be S corporations, limited partnerships, sole proprietorships, and other types of structures.[9] Because of the differences in the tax code, the independents need to be organized by corporate type to accurately assess profitability (most firms that fall into the "other" corporate structure category do not pay corporate taxes, thus, net income figures are effectively pretax).

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[9]S corporations are corporations that have elected to be taxed at the shareholder level rather than the corporate level under Subchapter S of the Internal Revenue Code. The other alternative structures also allow individual owners rather than the corporation to be taxed.

In general, 1992 and the preceding few years were hard ones in the U.S. oil and gas industry (OGJ, 1992). Mergers, acquisitions, consolidations, and liquidations were common in the years preceding 1992; the *Oil and Gas Journal*'s OGJ 400 was cut to 300 firms in 1991 (OGJ, 1991). OGJ cites periodic slumps in the prices of crude oil, natural gas, and petroleum products, and higher costs of operations due to environmental requirements as the driving force behind these reductions in the numbers of firms. As the results of the financial analysis of coastal firms show, 1992 also was not a good year for coastal firms and perhaps was somewhat harder on these firms than on the U.S. oil and gas industry as a whole. In general, 1993 was a somewhat better year among the OGJ 300 with a 75.5 percent increase in net income from 1992 to 1993 (OGJ, 1994d), although some of this improvement is attributable to accounting changes. Whether possibly both conditions were also felt by coastal firms is, however, not known.

A total of 213 Gulf operators provided enough financial data in the Section 308 survey to construct a profile of operators. These operators were divided into small and large operators on the basis of the RFA guidelines, which define a small oil and gas firm as one with 500 or fewer employees (Section Nine of this EIA presents financial information on firms under more detailed size breakdowns). Of the 213 operators that are used in this analysis, a total of 181 of these operators (or 85 percent) are small according to RFA guidelines; 32 (15 percent) are large. Most of these large operators (22 out of 32, or 69 percent of large operators in this group) are major oil companies as defined by the Pennwell Directory (Pennwell, 1994) (see Table 3-5).

Most independent oil companies in the analysis group are small (90 percent). Of the 181 small independents, only about a third have a standard corporate structure. The remaining two-thirds do not report corporate taxes.

Several analyses were performed to determine financial status of the Gulf firms. Medians were determined for the key financial variables of interest, since industry benchmarks are computed on the basis of medians and quartiles. All benchmarks are from Dunn & Bradstreet (1993) for SIC 1311 Petroleum and Natural Gas unless otherwise noted. A brief definition of the measures of financial health used to characterize the Gulf coastal firms are as follows:

- *Total Assets*. The sum of all liquid (cash-type) and nonliquid (e.g., real estate) assets of the company.

- *Equity*. Total assets minus total liabilities, or the firm's net worth.

- *Profitability*

  — Return on Assets (ROA): Net income over total assets. The median for the publicly held oil and gas production industry as a whole was 3.5 percent in 1992. The lowest quartile was -1.3.

  — Return on Equity (ROE): Net income over equity or net worth, which is total assets minus total liabilities. The median for the publicly held oil and gas production in industry was 6.2 percent in 1992. The lowest quartile was -2.0.

- *Leverage*

  — Interest Coverage Ratio (ICR): Earnings before interest payments and taxes over interest expense, which measures the ability of a company to meet interest and principal payments on debt. Most analysts like to see an ICR of 3 or more (Johnston, 1992).

- *Liquidity*

  — Working Capital: Current assets (cash-type assets) minus short-term debt (e.g., credit-line debt).

  — Current Ratio: Current assets over current liabilities provides a measure of working capital that can be compared to industry benchmarks. For this industry the median is 1.4. The lowest quartile is 0.9.

Benchmarks are useful in showing how healthy a firm or a subset of an industry is in comparison to the industry as a whole. In general, if the segment is at the median or above, it can be considered relatively healthy in comparison to the industry. Somewhat below the median would be considered weak but potentially acceptable financial health, while below the lowest quartile (only a quarter of firms in the industry have a measure that low or lower), financial health can be considered poor. If the financial health of the entire industry is poor relative to all industries, even better performing firms might be considered in poor financial health, however.

As Table 3-5 shows, the majors tend to have the greatest assets and equity. "Other" (not standard corporations) small firms tend to have the lowest assets and equity. Surprisingly, the

TABLE 3-5

MEDIAN FINANCIAL STATISTICS ON ASSETS, EQUITY, AND WORKING CAPITAL -- ALL FIRMS, GULF

Type of Firm	Number of Firms	Median Total Assets	Median Owner Equity	Median Working Captial	Median Current Ratio
Major	33	$4,457,177	$1,434,485	($7,154)	0.9304
Large independent	10	$1,209,872	$416,538	$18,889	1.1206
Small corporate independents	65	$54,511	$13,122	$1,184	1.2431
Other small independents	125	$1,853	$299	$6	1.0472
All small independents	190	$5,343	$663	$36	1.0711
All independents	200	$6,323	$930	$38	1.0711
All firms	233	$13,536	$3,060	$33	1.0609

majors tend to have very low levels of working capital. Among the majors, the median working capital is quite low, and the current ratio is less than one. Not one of the categories investigated has a current ratio at or above the industry median, although all are above the lowest quartile. Note that since no statistical testing has been performed in this analysis, it is unclear whether differences in measures between categories of firms are statistically significant. Thus, any differences are only potential, not necessarily actual, differences.

Because the impacts of the proposed effluent guidelines will fall primarily on firms that discharge produced water in the Gulf of Mexico, firms that could be identified as discharging (not all firms that are discharging could be identified because not all wells were surveyed) were assessed separately in Table 3-6. In general this subset does not appear to have strikingly different assets, equity, working capital, or current ratios from the overall coastal industry, with two exceptions. First, the majors have a median negative working capital and a current ratio slightly below the industry lowest quartile, and second, large independent dischargers have a substantially higher equity value. Again, the current ratio, while not at the median level for the industry, is still above to well above the lower quartile for all but the majors.

Total revenues attributable to the coastal oil and gas industry in the affected regions (Gulf and Cook Inlet) were $6.1 billion in 1992, according to data from the Section 308 survey. Total costs of production (not including general and administrative costs, taxes, interest, depletion or depreciation) were $1.6 billion in 1992. Tables 3-7 and 3-8 investigate the percentage of coastal costs and revenues to total costs and revenues at coastal firms. The greater the percentage of revenues derived from coastal operations, the potentially more substantial the impacts from the proposed effluent guidelines will be on affected firms. Overall, typical firms operating in the coastal region earn only a small fraction of their total revenues from coastal operations. On average, small independents with "other" corporate structures have the highest percentage of coastal revenues to total revenues—about 7 percent of their total revenues on average stem from coastal operations. Costs of operating in the coastal region for this same group is a slightly higher proportion of total costs than coastal revenues are to total revenues—over 8 percent. When the known dischargers are examined in Table 3-8, however, an interesting picture emerges. Although coastal revenue to total revenue is not substantially different from that for the total population (nearly 8 percent vs. 7 percent for the total

TABLE 3-6

MEDIAN FINANCIAL STATISTICS ON ASSETS, EQUITY, AND WORKING CAPITAL -- DISCHARGING FIRMS, GULF

Type of Firm	Number of Firms	Median Total Assets	Median Owner Equity	Median Working Captial	Median Current Ratio
Major	7	$2,499,540	$1,180,249	($45,125)	0.8675
Large independent	2	$2,903,472	$1,411,195	$28,479	1.1303
Small corporate independents	18	$69,235	$6,679	$361	1.2301
Other small independents	28	$1,889	$129	$1	1.0650
All small independents	46	$6,635	$574	$34	1.0829
All independents	48	$7,102	$707	$38	1.0829
All firms	55	$11,358	$4,050	$32	1.0692

TABLE 3-7

MEDIAN FINANCIAL STATISTICS ON REVENUES AND COSTS -- ALL FIRMS, GULF

Type of Firm	Number of Firms	Median Coastal Revenues	Median Ratio of Coastal Revenue to Total Revenue	Median Coastal Operating Costs	Median Ratio of Coastal Costs to Total Costs
Major	22	$27,298	0.0060	$6,067	0.0036
Large independent	10	$494	0.0013	$588	0.0094
Small corporate independents	59	$261	0.0252	$77	0.0264
Other small independents	122	$60	0.0706	$37	0.0809
All small independents	181	$100	0.0468	$57	0.0649
All independents	191	$100	0.0435	$57	0.0443
All firms	213	$163	0.0342	$79	0.0314

TABLE 3-8

MEDIAN FINANCIAL STATISTICS ON REVENUES AND COSTS -- DISCHARGING FIRMS, GULF

Type of Firm	Number of Firms	Median Coastal Revenues	Median Ratio of Coastal Revenue to Total Revenue	Median Coastal Operating Costs	Median Ratio of Coastal Costs to Total Costs
Major	7	$31,210	0.0049	$6,518	0.0030
Large independent	2	$22	0.0000	$4	0.0000
Small corporate independents	18	$752	0.0956	$348	0.0862
Other small independents	28	$157	0.0786	$96	0.2208
All small independents	46	$274	0.0888	$171	0.2087
All independents	48	$253	0.0786	$150	0.1104
All firms	55	$286	0.0603	$184	0.0857

population), coastal costs as a percentage of total operating costs are substantially higher—22 percent of total costs are incurred from coastal operations. Two conclusions might be drawn from this observation (assuming that this is a statistically significant difference). First, discharging coastal operations might be very marginal in many instances. Second, and more importantly, loss of coastal revenues (should wells be shut in) from discharging coastal operations might not result in major impacts because the typical discharging firm appears to maintain potentially much more profitable operations outside the coastal region that generate the bulk of total revenues.

Because many of these firms will not be discharging in 1996, it is not clear that this same result would apply to those who continue to discharge. The financial status of many of the firms that will continue to discharge in 1996 (including the proportion of coastal revenues and costs to total revenues and costs, where relevant) is investigated in detail in Section Six.

Tables 3-9 and 3-10 investigate the profitability of the coastal firms in terms of ROA and ROE. These indicators of financial health are typical of those used by investors to determine whether to make an investment in a firm. Another measure of financial health is the interest coverage ratio. This ratio is used by lenders (or bondholders) to determine the creditworthiness of a firm. All of these measures are useful for determining whether a firm might be able to make the capital investment (either through equity or borrowing) in pollution control equipment necessary to meet the proposed effluent guidelines. Again investors or lenders often compare a firm's ratios to industry benchmarks, as noted above.

As Table 3-9 shows, ROA and ROE reflect the relatively poor year for the industry. Moreover, medians for most categories of coastal firms (except the major's ROE) fall below medians on ROA and ROE (3.5 percent and 6.2 percent, respectively). All categories, however, are well above the lowest quartile. Even the firms that do not incur corporate taxes (and thus whose financial ratios are not directly comparable to the Dun & Bradstreet benchmarks) can be assumed to have on average at least positive returns (unlike the lowest quartile Dun & Bradstreet group, which showed returns of -1.3 on assets and -2.0 on equity). The interest coverage ratio, which is below the benchmark of 3 for all categories of coastal firms (except for the majors, which have a median of 3.0), indicates that the ability to borrow among this group

TABLE 3-9

MEDIAN FINANCIAL STATISTICS ON PROFITABILITY AND ABILITY TO BORROW -- ALL FIRMS, GULF

Type of Firm	Number of Firms	Return on Assets	Return on Equity	Interest Coverage Ratio
Major	22	0.0224	0.0764	2.9557
Large independent	10	0.0090	0.0294	1.0714
Small corporate independents	59	0.0128	0.0303	1.3265
Other small independents	122	0.0002	0.0209	1.1273
All small independents	181	0.0082	0.0260	1.2576
All independents	191	0.0082	0.0260	1.1735
All firms	213	0.0108	0.0347	1.4394

TABLE 3-10

MEDIAN FINANCIAL STATISTICS ON PROFITABILITY AND ABILITY TO BORROW -- DISCHARGING FIRMS, GULF

Type of Firm	Number of Firms	Return on Assets	Return on Equity	Interest Coverage Ratio
Major	7	0.0213	0.0521	3.1812
Large independent	2	0.0283	0.0519	2.7991
Small corporate independents	18	0.0136	0.0276	2.2731
Other small independents	28	0.0002	0.0000	1.4471
All small independents	46	0.0020	0.0003	1.8571
All independents	48	0.0020	0.0003	1.8571
All firms	55	0.0040	0.0148	1.8571

might be restricted. This result means that measures of these firms' ability to use their equity and working capital could be very important to this analysis. As a whole, the coastal firms appear to be somewhat weak financially, but not, on average, among the weakest groups in the industry.

Table 3-10 presents ROA, ROE, and interest coverage ratios for the known discharging firms. In some cases, this group appears slightly stronger financially than the coastal industry firms as a whole, although certain subsets show weaker performance on some measures, returns are still above the lowest quartile. The interest coverage ratio is still below 3 for all groups but the majors, although possibly slightly better than that for the coastal group as a whole. The group of known dischargers is weak financially, but again, as for the coastal group as a whole, not among the weakest groups in the industry. Equity and working capital measures also might be important indicators of impacts in the discharging group due to potential limitations in the ability of this group to borrow capital.

Several overall conclusions about the Gulf coastal operators can be made. Differences between known dischargers and all operators are probably not great and are likely to follow no particular pattern. Based on the arbitrary divisions made between groups in terms of size and corporate structure, in some cases known dischargers appear possibly a little healthier than nondischargers. Neither group is particularly financially healthy when compared to the industry as a whole. In most cases, however, on average, both known dischargers and the group of all Gulf coastal operators fall within the range between median and lowest quartile, which can be characterized as weak but not poor financial performance.

Firms Operating in Cook Inlet

The Cook Inlet operators[10] generally appear to be about as healthy financially as the Gulf of Mexico major operators as a group (the Cook Inlet operators also are majors). Median

[10]Numbers for this concerns about section were taken from annual reports only. Because of concerns about confidential business information and the small numbers of operators involved, medians for coastal revenues and operating costs are not presented.

total assets and equity are somewhat higher (see Table 3-11) among the Cook Inlet operators than among the Gulf coast majors, and median working capital and the current ratio are also higher (the current ratio is 1.09 compared to 0.98 among the Gulf coast majors) although whether these differences are significant has not been determined. Return on assets is not appreciably different between Gulf and Cook Inlet operators (both groups show about a 2 percent median ROA, which is below the industry median of 3.5 percent, but well above the lowest quartile of -1.3 percent). Return on equity might be slightly better among the Gulf majors (7.6 percent as compared to 6.8 percent among the Cook Inlet majors), but both groups are somewhat above the median 6.2 percent return noted for the industry. The interest coverage ratio is below 3 (i.e., 2.0), and is slightly lower than the median for the Gulf majors (i.e., 3.0).

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TABLE 3-11

MEDIAN FINANCIAL STATISTICS -- ALL FIRMS, COOK INLET

Financial statistic	Median value
Total assets	$17,862,000
Owner equity	$5,028,000
Working capital	$156,000
Current ratio	1.0876
Return on assets	0.0195
Return on equity	0.0685
Interest coverage ratio	2.0203

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SECTION FOUR

ECONOMIC IMPACT ANALYSIS METHODOLOGY OVERVIEW AND AGGREGATE COMPLIANCE COST ANALYSIS

4.1 OVERVIEW OF METHODOLOGIES

This analysis discusses the impacts of the proposed and selected regulatory options for effluent limitations guidelines and standards for the coastal subcategory of the oil and gas production industry in the affected coastal regions (i.e., the Texas/Louisiana portion of the Gulf of Mexico Region, known here as the Gulf of Mexico region,[1] and Cook Inlet, Alaska). The overall analysis covers:

- Compliance costs to industry.
- Production losses (in terms of quantities of hydrocarbons not produced compared to a no-regulation [baseline] scenario).
- Lost economic lifetime (i.e., the loss of productive years associated with wells shutting in earlier under the regulation than under a baseline scenario).
- Numbers of wells immediately ceasing production as a result of the regulation (first-year shut in).
- Losses of revenues to operators, in terms of annualized losses and net present value (NPV) of production,[2] state governments, and the federal government.
- Firm-level impacts (firm failure analysis).
- Employment impacts (losses and gains in employment).
- Balance of trade and inflation impacts.
- Regulatory flexibility (an analysis of whether impacts are disproportionate on small businesses).

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[1]All discussions of the Gulf of Mexico address Texas and Louisiana operations only.

[2]NPV is the total stream of production revenues minus costs over a period of years (the well's or platform's lifetime) discounted back to present value.

- Impacts on new sources (which looks at impacts on NPV and the internal rate of return [another measure of profitability]).

These individual analyses are interrelated, with the output of one analysis often used as input for another analysis. The general flow of the analyses and their relationship to one another are shown in Figure 4-1. As the figure shows, the first step in the analysis is to identify the appropriate inputs. Because compliance costs (capital as well as operating and maintenance [O&M] costs) are one of the major inputs to all of these analyses, how these costs are annualized is a key methodological decision. Section 4.2 discusses how and why costs are annualized, Section 4.3 describes all the regulatory options under consideration and the options selected for these effluent guidelines, and Section 4.4 presents total aggregate compliance costs associated with each of the BAT regulatory options and the effluent guidelines as a whole (the costs for the selected regulatory options).

The first major analysis following cost annualization is the production loss analysis.[3] In general, this analysis uses well-specific compliance costs calculated based on volumes of wastes generated by each discharging well or platform surveyed in the Section 308 survey.[4] The well-specific cost is determined using a cost per barrel derived from the compliance costs (capital and O&M) estimated for each treatment facility (for Gulf region produced water) or derived from the compliance costs associated with each operator (Cook Inlet produced water drilling wastes). This analysis uses an economic model of surveyed wells (Gulf of Mexico) and platforms (Cook Inlet, Alaska) to look at annual cash flow and production decisions (produce/shut in) based

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[3]The cost annualization used in this section (Section Four), Section Five for the Gulf model only, and Section Six is a simple method using only the discount rate and number of years assumed to be the average life of wells or platforms or over which drilling occurs. The production loss model for Cook Inlet uses a much more sophisticated method to annualize costs that takes into account accelerated depreciation and the modeled life of each platform (see Section 5.1). The simple annualization used in Section Four, in Section Five for defining impacts in the Gulf, and in Section Six produces pretax estimates of compliance costs and thus overstates costs and impacts to producers. The more sophisticated Cook Inlet model calculates the actual cost in each year faced by producers (a posttax cost).

[4]Compliance costs in terms of capital and O&M costs to achieve different levels of control were derived separately from this economic analysis effort and are presented in a separate document (see U.S. EPA, 1995, for more details on the derivation of compliance costs).

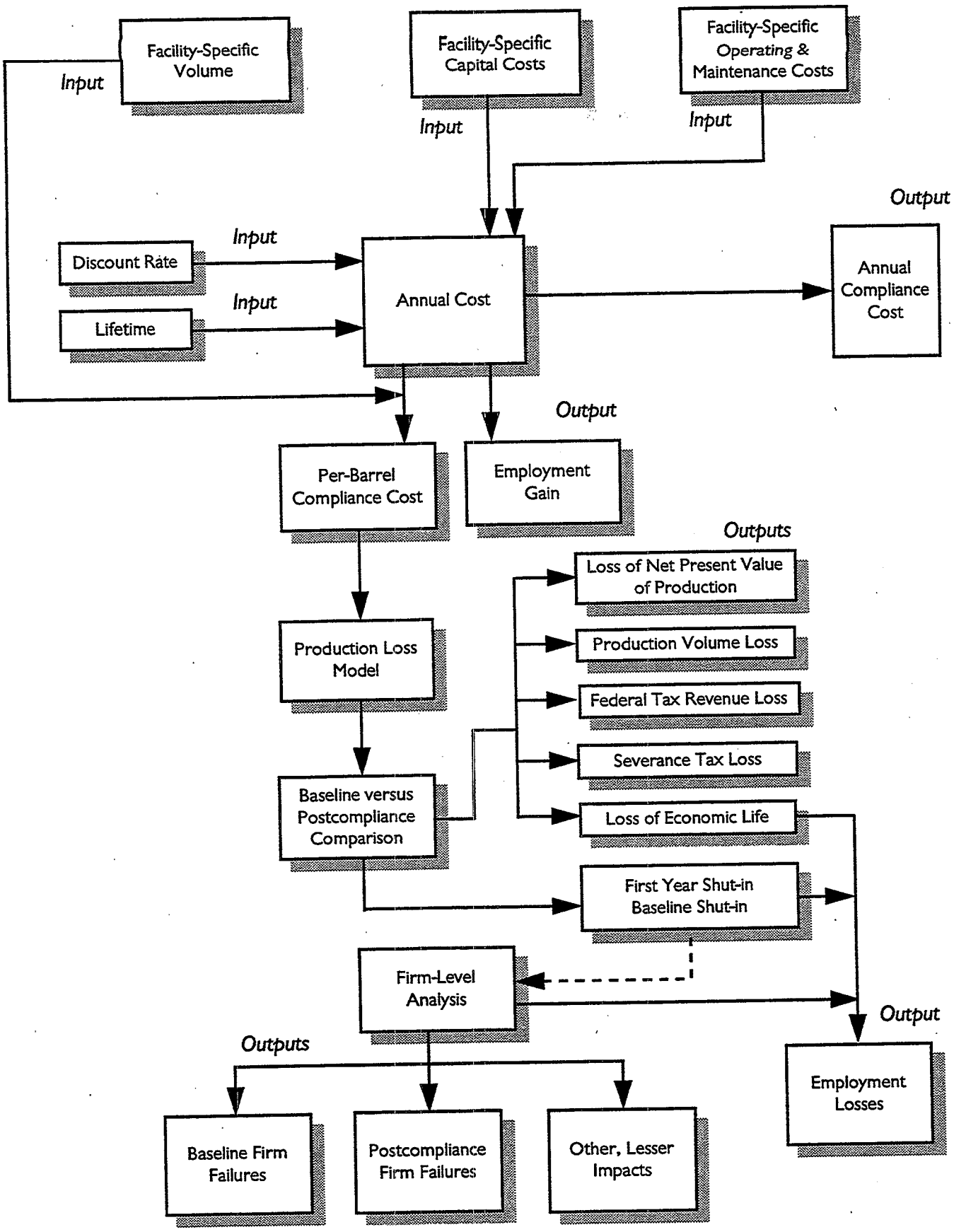

Figure 4-1. Overview of methodology for the economic impact analysis.

primarily on cash flow (see Section Five for more details). Compliance costs and production losses lead to losses in economic lifetimes (the decision to shut in is made earlier than if the regulation were not in effect), which leads to production losses. Sometimes the decision process indicates that the operator would shut in a well or platform as soon as the regulation becomes effective (a first-year shut-in); this result is also noted. Compliance costs and production losses also lead to declines in the present value of net income (i.e., NPV), which can be estimated when the model outputs from a baseline scenario are compared to those from a postcompliance scenario. The detailed methodology for the production loss modeling is discussed in Section Five and Appendix A. Results are presented in Section Five.

Production losses, first-year well shut-ins, and declines in the present value of net income (NPV) lead to secondary impacts on federal and state revenues (see Section Five), operator revenues (see Section Five), employment (see Section Seven), and possibly the balance of trade and inflation (see Section Eight). The nature of the Section 308 survey is such that well impacts cannot be linked to individual operators (operators were censused but wells were surveyed, and wells were not selected on an operator-by-operator basis); thus, firm-level impacts are investigated separately from well- or platform-based impacts. On a case-by-case basis, however, where such information is available, specific model results are added to the firm failure analysis results.

Annual compliance costs are again used for the firm-level analysis, compiled on an operator-by-operator basis. These costs are compared to working capital and equity among the affected firms. Where a reduction in working capital or equity exceeds 5 percent, a more in-depth analysis is undertaken, looking at well-specific data, where possible, to identify whether firm failure is a possibility (see Section Six).

4.2 COST ANNUALIZATION PURPOSE AND METHOD

Cost annualization is used to estimate the annual compliance cost to the operators of new pollution control equipment. The cost of additional pollution control equipment can be divided between two components: the initial capital investment to purchase and install the equipment,

and the annual cost of operating and maintaining such equipment. Capital costs are a one-time expense incurred only at the beginning of the equipment's life, and O&M costs are incurred every year of the equipment's operation.

To determine the economic feasibility of upgrading a treatment facility or transporting and disposing wastes at a commercial facility, the costs must be compared against the well's annual revenues and its operator's capital structure. The initial capital outlay should not be compared against the well's or operator's income in the first year because this capital cost is incurred only once. Additionally, annualizing costs over several years reflects the common practice of financing capital expenditures. This initial investment, therefore, should be spread out over either the well's or platform's life or the equipment's life. Annualizing costs is a technique that allocates the capital investment over the lifetime of the equipment, incorporates a cost-of-capital factor to address the costs associated with raising or borrowing money for the investment, and includes annual O&M costs. The resulting annualized cost represents the average annual payment that a given company will need to make to upgrade its facility. The annualized cost is analogous to a mortgage payment, which spreads the one-time investment in a home into a series of constant monthly payments. As noted above, cost annualization in this section (and for the Gulf model in Section Five and in Section Six) is a simplified version of the cost annualization performed in the Cook Inlet model.

In this section, costs are annualized using two inputs: discount rate and time period over which payments are made. The discount rate was calculated using the Section 308 survey responses to a question asking respondents for their cost of capital. The average cost of capital over all coastal respondents was reported as 8 percent, and this is used as the discount rate. The time period over which costs are annualized varies, depending on the waste stream under consideration and the location of the affected wells or platforms. In Cook Inlet, remaining platform lives average 11 years in the baseline, although under some options these lives could be slightly less; thus, a 10-year remaining project life was assumed in this section for produced water options. Drilling will most likely only take place over a 7-year period (UNOCAL/Marathon,

1994).[5] Because the drilling waste disposal equipment might not be used past this 7-year life, a 7-year period has been used to amortize the capital costs of drilling-waste disposal options.[6] In the Gulf of Mexico, currently productive wells are expected to have an average economic life of about 15 years, but under postcompliance options this average life drops to as little as 10 years (see Section Five for the analysis that estimates this economic life). Because well life does not necessarily relate to treatment facility life (wells can be shut in and new wells can be drilled to replace them), the 10-year period over which to amortize costs also was considered a conservative estimate of project lifetime. The shorter the time frame used in the analysis, the more conservatively high will be the estimate of annual compliance costs.

The cost annualization for drilling wastes in this section was performed in a slightly different manner than for the other waste streams. Unlike the other wastes, which could be considered to be disposed every year, drilling wastes are disposed of sporadically with each well drilled. Based on a drilling schedule provided by Cook Inlet operators, the above discount rate and time period assumptions, and capital and O&M costs provided by SAIC, which determined costs for all drilling projects planned through 2002 (EPA, 1995), a present value for all costs over the 7-year period was calculated and then annualized to create a consistent stream of payments over the timeframe. This approach is discussed in more detail in Section 4.3.2.

4.3 THE REGULATORY OPTIONS

The engineering cost estimates that feed into the cost annualization model are based on a set of regulatory options developed by EPA. This section summarizes these options. The

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[5]Industry supplied EPA with its plans to drill in Cook Inlet until 2002—approximately 7 years after the expected promulgation date of this rule. Beyond that date, drilling plans could not be provided. Thus drilling costs are annualized over 7 years, rather than a longer time period to provide a conservatively high estimate of annual compliance costs.

[6]This is a conservative assumption that overstates compliance costs as reported in this section. In Section Five, the Cook Inlet model is able to determine the actual life of the platforms in question to compute a more precise, posttax compliance cost estimated to affect producers.

derivation of the initial engineering cost estimates under each option is discussed in the Development Document (U.S. EPA, 1995).

EPA is required under Sections 301, 304, 306, and 307 of the Clean Water Act (the Act) to establish effluent limitations guidelines and standards of performance for industrial dischargers. To further these requirements, EPA has proposed the following effluent guidelines and standards:

- BPT—For produced sand only.
- BCT—Effluent reductions employing the best conventional pollutant control technology as required under Section 304(b)(4).
- BAT—Effluent reductions employing the best available control technology economically achievable as required under Section 304(b)(2).
- NSPS—New source performance standards covering direct discharging new sources as required under Section 306(b) of the Act.
- PSES—Pretreatment standards for existing sources.
- PSNS—Pretreatment standards for new sources.

Best practicable technology (BPT) regulations were promulgated in 1979.

For the purposes of analysis, the range of BCT, PSES, NSPS, and PSNS options evaluated by EPA are identical to BAT options although the pollutants controlled through BCT requirements are total suspended solids (TSS) and oil and grease only (conventional pollutants).[7] No existing indirect dischargers are known and no new indirect dischargers are anticipated; thus, PSES and PSNS options for indirect dischargers are not associated with any costs or impacts. (In all cases selected PSES and PSNS options equal NSPS options.) This section discusses the BAT, NSPS, and BCT options for the following waste streams:

- Produced water

[7]Preferred BCT options, however, in some instances differ from preferred BAT options.

- Drilling fluids and cuttings
- Well treatment, workover, and completion wastes (TWC)

The following waste streams also are regulated:

- Deck drainage from platforms
- Produced sand
- Sanitary waste
- Domestic waste

This EIA does not assess impacts associated with these four wastestreams because EPA is proposing regulatory options for them that are equal to current practice and therefore impose no costs to the industry. Note also that this EIA does not assess impacts outside the Gulf of Mexico (Texas and Louisiana only) and Cook Inlet regions, since no coastal oil and gas operations outside these two regions currently discharge wastes nor are they expected to in the future (see Section Three).

The BAT, NSPS, and BCT options for produced water, drilling waste, and TWC are described below in detail. (BAT options considered for each of these types of waste are summarized in Table 4-1.) Preferred options for produced sand, deck drainage, sanitary waste, and domestic wastes also are briefly discussed.

4.3.1 Produced Water

Some operations in both the Gulf of Mexico and Cook Inlet currently discharge produced water (this analysis does not take into account the requirements of EPA Region 6 General Permits for the Coastal Oil and Gas Industry covering disposal of produced water). The five BAT options proposed for produced water are as follows:

- Option #1 is identical to BPT (a no-cost alternative).

TABLE 4-1

BAT REGULATORY OPTIONS CONSIDERED IN THE ECONOMIC IMPACT ANALYSIS

Type of Waste Stream	Name	Description
Produced water	Option #1	BPT—current regulatory requirement
	Option #2	Offshore limitations
	Option #3	Zero discharge/BPT Cook Inlet
	Option #4	Zero discharge/offshore limitations Cook Inlet
	Option #5	Zero discharge
Drilling wastes	Option #1	Zero discharge/offshore limitations Cook Inlet
	Option #2	Zero discharge/offshore limitations plus 1-million-ppm toxicity limit Cook Inlet
	Option #3	Zero discharge
TWC	Option #1	BPT
	Option #2	Zero discharge/offshore limitations Cook Inlet

- Option #2 requires all operations, including those in the Gulf of Mexico and Cook Inlet, to meet the same limitations as those required of offshore operations (these limitations can be met using improved gas flotation technology).

- Option #3 requires zero discharge, except that Cook Inlet operations are allowed to continue with BPT practices.

- Option #4 requires zero discharge, except that Cook Inlet operations are required to meet offshore limitations (which can be achieved using improved gas flotation technology).

- Option #5 requires all operations, including those in the Gulf of Mexico and Cook Inlet, to meet zero-discharge requirements (which can be met either through the use of injection wells or through transportation of wastes to commercial disposal facilities).

The preferred BAT regulatory option is Option #4, which prohibits discharge in the Gulf of Mexico but allows operations in Cook Inlet to meet offshore limitations. The selected NSPS option is Option #5 (zero discharge, all regions) (see Section Ten for a discussion of NSPS analyses). All options fail the BCT cost test (see EPA, 1995, for more details on BCT cost tests), so BCT is set equal to BPT.

4.3.2 Drilling Fluids and Cuttings

All coastal areas are currently achieving zero discharge of drilling fluids and cuttings with the exception of Cook Inlet. EPA Region 6 has promulgated a General Permit prohibiting the discharge of drilling fluids and cuttings (58 FR 49126, September 21, 1993); discharge of these wastes also is prohibited in states outside Region 6 with coastal oil and gas operations (see Section Three), except for Alaska. Also included in this waste stream is drill water effluent, but little to no drill water effluent is currently discharged (EPA, 1995). Three BAT options are proposed:

- Option #1 requires zero discharge, except that Cook Inlet operations are required to meet offshore limitations (30,000 ppm toxicity limitation). This option reflects current practice and is a no-cost alternative.

- Option #2 requires zero discharge, except that Cook Inlet operations are required to meet offshore limitations with a 100,000- to 1-million-ppm toxicity limitation in the suspended particulate phase (SPP).

- Option #3 requires zero discharge, regardless of location.

EPA is co-proposing all three options. The selected NSPS option is NSPS=BAT (i.e., whichever BAT option is selected for promulgation, NSPS will be set to equal that option). Since neither Option #2 nor Option #3 passes the BCT cost test, BCT is set equal to BPT. Note that because drilling wastes are only being discharged in Cook Inlet, operations in this region alone will incur BAT costs. Additionally, because no new platforms subject to NSPS requirements are expected to be constructed in Cook Inlet, no NSPS costs are anticipated.

4.3.3 TWC Wastes

Two BAT options are considered for TWC:

- Option #1 requires BPT (except in Region 6 freshwaters, where zero discharge would be required, which is current practice).

- Option #2 requires TWC limitations to equal the selected produced water option (in this case zero discharge, except for improved gas flotation in Cook Inlet).[8]

Options #1 and #2 are co-proposed. The selected NSPS option is NSPS=BAT (i.e., depending on whichever BAT option is selected for promulgation). Since Option #2 fails the BCT cost test, BCT is set equal to BPT.

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[8]This is a no-cost option for Cook Inlet, since TWC is commingled with produced water and costs calculated for produced water disposal include the cost of disposing of the commingled waste.

4.3.4 Other Miscellaneous Wastes

For produced sand, zero discharge is proposed for BPT, BAT, and NSPS. BCT is set equal to BPT. This is a no-cost option (zero discharge is current practice).

For deck drainage, BAT and NSPS requirements are proposed to be the same as BPT: no free oil. No costs or impacts are expected because the proposed requirements are current practice. BCT is set equal to BPT (the other option fails the BCT cost test).

The proposed NSPS and BCT options for sanitary waste are set equal to BPT (and no discharge of foam for NSPS). No BAT limitations are considered because the only parameters considered for regulation are conventionals. No costs or impacts are expected because the proposed requirements are current practice.

The proposed options for domestic wastes are NSPS equal to BPT (and no discharge of foam for NSPS), BCT equal to BPT, and no discharge of foam for BAT. No costs or impacts are expected because the proposed requirements are current practice.

4.4 AGGREGATE COMPLIANCE COSTS

This section calculates the aggregate compliance costs for BAT options for the waste streams considered in this EIA and also estimates costs of NSPS in the selected option for produced water and for Option #2 for TWC (NSPS costs for other waste streams are zero).

4.4.1 BAT Options

4.4.1.1 Produced Water

The aggregate compliance costs for produced water are derived from estimates of capital and operating costs for the following types of locations and pollution control approaches (see U.S. EPA, 1995):

- Gulf of Mexico
  - Improved gas flotation: Capital and operating expenditures to install improved gas flotation equipment (i.e., equipment capable of meeting the more stringent offshore limitations on grease and oil) at discharging separation/treatment facilities were estimated. The discharging separation/treatment facilities of concern are those that will still have discharge permits in 1996. The most recent permit data from the Louisiana Department of Environmental Quality and the Texas Railroad Commission were used to identify current dischargers. The regulatory baseline, however, requires that only those operations discharging after third quarter 1996 be considered. Therefore, treatment facilities were identified as likely to be operating after the third quarter 1996 using reviews of permit compliance schedules in the Louisiana permit database, reviews of court-ordered compliance schedules for Texas dischargers, and information obtained from the Section 308 survey concerning whether the facility would be operating in 1996. Only the treatment facilities continuing to discharge in 1996 were assigned costs.
  - Zero discharge: Capital and operating expenditures to install injection wells or to transport produced water to commercial disposal facilities were estimated for the same group of treatment facilities identified above. In general, injection wells were assumed to be installed at the larger treatment facilities, whereas produced water from the smaller facilities was assumed to be transported to a commercial disposal facility.
- Cook Inlet
  - Improved gas flotation: Costs to install and operate improved gas flotation equipment were derived for each platform (where platform treatment and discharge currently takes place) or centralized onshore treatment facility (where produced water is piped to shore for treatment).
  - Zero discharge: Costs to install and operate injection wells, as well as relevant piping, were derived for each platform or onshore treatment facility.

TABLE 4-2

AGGREGATE ANNUAL COSTS FOR BAT OPTIONS BY REGULATORY OPTIONS ($1992)

Type of Waste Stream	Option Number	Aggregate Annual Cost (Pretax)
Produced water	Option #1	$0
	Option #2	$12,371,872
	Option #3	$28,615,098
	Option #4	$30,862,336
	Option #5	$50,693,181
Drilling wastes	Option #1	$0
	Option #2	$1,370,685
	Option #3	$3,889,386
TWC	Option #1	$0
	Option #2	$605,645

Source: ERG estimates based on SAIC engineering costs from U.S. EPA (1995).

Once the capital costs were annualized and added to operating costs, costs for each of these options within regions were combined, yielding the costs of the regulatory options (i.e., Option #2, improved gas flotation, used the sum of costs for improved gas flotation among all facilities in the Gulf of Mexico with the costs of gas improved flotation derived for the platforms and onshore treatment facilities in Cook Inlet).

Aggregate compliance costs for Options #1 through #5 are shown in Table 4-2. The compliance costs (other than for Option #1) range from $12.4 million to $50.7 million. The selected option, Option #4, is associated with costs totaling $30.9 million. Note that all compliance costs have been calculated pretax. This approach overestimates the annual costs to industry, because the state and federal governments will partially subsidize these expenditures through deductions for accelerated capital equipment depreciation and increased operating costs, which serve to reduce taxable income. Although posttax compliance costs to industry are not calculated, the reduction in tax revenues to the state and federal governments from both compliance cost effects and production losses is estimated in Section Five.

4.4.1.2 Drilling Waste

Aggregate compliance costs for drilling wastes (Cook Inlet only) are derived from estimates of capital and operating costs for the following types of pollution control approaches (see U.S. EPA, 1995):

- 1-million-ppm toxicity limit: Operations likely to use landfills or dedicated disposal wells were identified based on discussions with the operators in Cook Inlet (U.S. EPA, 1995). Costs per barrel of waste disposed were calculated for landfill disposal. Capital costs of installing injection wells and injection equipment and modifying platforms were developed. Operating costs for injection wells were also derived. All operating costs were converted to a cost per new or recompleted well drilled based on volume expected to require disposal (17 percent of all drilling waste generated—see U.S. EPA, 1995). A drilling schedule was then developed based on discussions with operators (Table 4-3). A cost schedule was developed based on the drilling schedule (Table 4-4). In the first year, all capital costs for any operators incurring a capital cost are included plus the costs to dispose of wastes from the number of wells planned to be drilled in the first year. The second and subsequent years only include costs for disposing the wastes from

TABLE 4-3

DRILLING SCHEDULE

	YEAR															
	1996		1997		1998		1999		2000		2001		2002		Totals	
Platform	New	Recomp.	New	Recomp.	New	Recomp.	New	Recomp.	New	Recomp.	New	Recomp.	New	Recomp.	New	Recomp.
SWEPI A	3									1					3	1
SWEPI C															0	0
Granite Point	3														3	0
Spark			3												3	0
Dolly Varden				3											0	3
Grayling			3												3	0
King Salmon				3											0	3
Steelhead	3												3		6	0
Monopod				3											0	3
Baker		3				3				3					0	9
Dillon	3				3										6	0
Anna					3										3	0
Bruce	3														3	0
Tyonek A															0	0
ARCO Sunfish	*3*		*3*							*3*					*6*	*3*
Total	18	3	9	9	6	3	0	0	0	7	0	0	3	0	36	22
Yearly Total		21		18		9		0		7		0		3		58

Sources: UNOCAL/Marathon, 1994.
Marathon Oil Co., correspondence with EPA, 12 April 1994.
ARCO, telephone contact between Allison Wiedeman, EPA, and ARCO, Alaska, May 9, 1994.
SAIC, Supplemental Worksheet, April 12, 1994.

TABLE 4-4

COST ANNUALIZATION OF DRILLING COSTS FOR 1-MILLION-PPM TOXICITY LIMIT

	1996	1997	1998	1999	2000	2001	2002	Total	NPV	Annual Cost
UNOCAL/MARATHON	$1,173,782	$694,904	$608,493	$0	$43,205	$0	$282,644	$2,803,028	$2,359,969	$453,285
SHELL	$2,396,319	$0	$0	$0	$9,254	$0	$0	$2,405,573	$2,225,112	$427,383
ARCO	$2,596,973	$171,000	$0	$0	$0	$0	$0	$2,767,973	$2,551,210	$490,017
TOTAL	$6,167,073	$865,904	$608,493	$0	$52,459	$0	$282,644	$7,976,574	$7,136,291	$1,370,685

Source: ERG estimates based on EPA, 1995.

TABLE 4-5

COST ANNUALIZATION OF DRILLING COSTS FOR ZERO-DISCHARGE OPTION

	1996	1997	1998	1999	2000	2001	2002	Total	NPV	Annual Cost
UNOCAL/MARATHON	$6,904,627	$4,087,640	$3,579,379	$0	$254,131	$0	$1,662,624	$16,488,401	$13,882,175	$2,666,383
SHELL	$2,396,314	$0	$0	$0	$9,259	$0	$0	$2,405,573	$2,225,111	$427,382
ARCO	$4,315,346	$171,000	$0	$0	$0	$0	$0	$4,486,346	$4,142,296	$795,621
TOTAL	$13,616,286	$4,258,640	$3,579,379	$0	$263,390	$0	$1,662,624	$23,380,320	$20,249,581	$3,889,386

Source: ERG estimates based on EPA, 1995.

wells planned. The net present value of these expenditures was calculated and then annualized over the 7-year period to produce a consistent stream of expenditures over the 7-year period (Table 4-4).

- Zero-discharge limit: The same procedure was followed as that presented above with one major exception. Instead of assuming that 17 percent of drilling waste would need to be disposed of, all waste was assumed to require disposal. Costs increase for two reasons. First, since total volumes disposed per well increase, costs per well drilled increase. Second, the increase in total volumes requires the installation of one additional injection well for one operator; thus, capital costs also increase (Table 4-5).

The aggregate compliance costs for Options #1 through #3 are shown in Table 4-2. Compliance costs range from $0 to $3.9 million.

4.4.1.3 TWC

EPA is co-proposing Options #1 and #2 for TWC. Option #1 is equivalent to BPT; Option #2 requires zero discharge in the Gulf and offshore limitations for Cook Inlet. Because TWC fluids can be commingled with produced water, EPA has selected these same requirements as the preferred produced water option as Option #2 for TWC. All costs for TWC in Cook Inlet are inherently part of the costs to meet produced water options in Cook Inlet because TWC is currently commingled there. Thus, no additional costs are incurred for this TWC option in Cook Inlet. But for the Gulf, incremental costs for disposing of TWC would be incurred under Option #2. The costs for TWC disposal under Option #2 in the Gulf are O&M costs only.

Costs for disposing of TWC under Option #2 are generated similarly to that for Gulf of Mexico produced water (i.e., facility-by-facility with zero discharge achieved assuming commercial disposal or injection, depending on the size of the permitted treatment facility). Costs for each option are shown in Table 4-2. Compliance costs are approximately $0 or $0.6 million per year.

TABLE 4-6

AGGREGATE ANNUAL COSTS FOR SELECTED BAT REGULATORY OPTIONS ($1992)

Type of Waste Stream	Selected Option Number	Aggregate Annual Cost Range (Pretax)
Produced water	Option #4	$30,862,336
Drilling waste	Options #1, #2, or #3	$0 to $3,889,386
TWC	Options #1 or #2	$0 to $605,645
Total		$30,862,336 to $35,357,367

Source: ERG estimates based on SAIC engineering costs from U.S. EPA (1995).

4.4.1.4 Total Aggregate Compliance Costs for the Selected BAT Regulatory Options

Table 4-6 presents the total aggregate compliance costs for the selected regulatory options. These regulatory requirements will amount to $30.9 to $35.4 million annually, depending on which drilling waste and TWC options are selected.

4.4.2 NSPS Cost Estimate for Produced Water

EPA estimates that six new projects will be constructed in the Gulf of Mexico each year over the next 15 years (U.S. EPA, 1995). Total capital costs for a zero-discharge option were estimated to be $2,038,738 and O&M costs were estimated to be $370,549.

Capital costs for six projects are assumed to be incurred in every year, and every year there is an additional O&M cost for each new project. Thus, in year 1 capital costs for six projects and O&M costs for six projects are incurred. In year 2, capital costs for six projects and O&M costs for 12 projects are incurred. In year 3, capital costs for six projects and O&M costs for 18 projects are incurred, and so on out to 15 years. The present value of these capital and O&M outlays over 15 years[9] is then computed (at an 8 percent real discount rate). Note that it is assumed that the initial outlay occurs at the end of 1996 and recurs at the end of every period thereafter (as opposed to occurring at the beginning of the period, which provides a slightly different result). The present value is then annualized. The total present value of the zero-discharge option is $38.4 million with an annual cost of $4,482,309 (Table 4-7).

4.4.3 NSPS Cost Estimate for TWC

EPA estimates that 45 new wells meeting the definition of a new source will be drilled each year and will require annual disposal of TWC fluids (U.S. EPA, 1995). The costs per year

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[9]A 15-year lifetime is assumed rather than 10 years because new wells or projects should have a longer productive life than existing wells or projects.

TABLE 4-7

TOTAL ANNUAL COSTS FOR ALL SELECTED REGULATORY OPTIONS
($1992)

Type of Waste Stream	Selected Option Number	Aggregate Annual Cost Range (Pretax)
Produced water	Option #4	$30,862,336
Drilling waste	Option #1, #2, or #3	$0 to $3,889,386
TWC	Options #1 or #2	$0 to $605,645
NSPS, produced water	Option #4	$4,482,309
NSPS, TWC	Options #1 or #2	$0 to $519,848
Total		$35,344,645 to $40,359,524

Source: ERG estimates based on SAIC engineering costs from U.S. EPA (1995).

for each group of 45 wells will total $78,831 for the preferred no discharge option. As above, each year another group of 45 wells are assumed to begin production, so in the first year, $78,831 will be incurred, in the second year, $157,662, and so on out to 15 years. The present value of these O&M outlays over 15 years is then calculated and annualized as for produced water, above. The total annual cost of NSPS for TWC is computed to be $4,449,627 in present value or $519,848 annually. Depending on which NSPS option is chosen (based on choice of BAT option), costs will thus be $0 to $0.5 million per year.

4.4.4 Total Estimated Cost of the Effluent Guidelines

The estimated cost of the effluent guidelines is $30.9 to $35.4 million per year for BAT requirements and $4.5 to $5.0 million per year for NSPS requirements, for a total of $35.3 to $40.4 million per year. Thus, this rulemaking does not qualify as a major rule under Office of Management and Budget (OMB) guidelines (Executive Order 12866) and a Regulatory Impact Analysis (RIA) is not required. Note that the total maximum cost of the rule ($40.4 million) is a very small percentage of coastal revenues and operating costs (the direct costs of operating the business, i.e., not including general and administrative costs, depletion, depreciation, taxes, interest, etc.). Total revenues among coastal firms (Texas, Louisiana, and Cook Inlet, Alaska, only) are estimated to be $6.1 billion per year. Thus, the total annual cost of the Coastal Guidelines is estimated to be 0.7 percent of annual coastal revenues. The total annual coastal operating costs among coastal firms is estimated to be $1.2 billion; thus, annual compliance costs are 3.3 percent of total annual operating costs.

4.5 REFERENCES

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U.S. EPA. 1993. Economic Impact and Regulatory Flexibility Analysis of Proposed Effluent Guidelines and NESHAP for the Pulp, Paper, and Paperboard Industry. EPA-821-R-93-021. Office of Water. November.

U.S. Environmental Protection Agency. 1995. Development Document for Proposed Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category. EPA, January 31.

SECTION FIVE

PRODUCTION LOSS IMPACTS AND OTHER IMPACTS TO WELLS AND FACILITIES

This section describes the production loss model developed to simulate the economic performance of coastal production and drilling projects. Note that firm-level impacts are discussed in Section Six. Analysis of Cook Inlet, Alaska, projects incorporates current production, future drilling, and future production, while Gulf of Mexico projects are analyzed in current production scenarios only because of a lack of information on planned drilling in the Gulf.[1] Section 5.1 presents a description of the economic simulation methodology for Cook Inlet, and Section 5.2 describes the Gulf of Mexico model. The results of production loss modeling for both Cook Inlet and the Gulf of Mexico are presented in Section 5.3. Although the Cook Inlet and Gulf of Mexico models have similar bases, a number of differences distinguish the models sufficiently to warrant separate presentations. In all analyses, a baseline is defined, in which the modeled wells and platforms are assumed to be operating without incremental compliance costs. This baseline scenario is compared to a postcompliance scenario to estimate the incremental impacts of the rulemaking.

Appendix A of this EIA presents a selection of detailed derivations of assumptions used in these models. Appendix B provides greater detail for the Cook Inlet production loss model and presents the calculations summarized in the report text. Appendix C presents details of the Gulf of Mexico production loss model.

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[1]The impact to new BAT wells (i.e., development wells added to existing treatment facilities without extensive site preparation work) in the Gulf coastal region should be minimal since these wells will typically face the marginal cost rather than the average cost of disposal (the cost to add an additional volume of produced water to a treatment facility, given sufficient capacity, is much less than the average cost per existing well to convert to zero discharge. Furthermore, these costs should be substantially offset by a new development well's rate of hydrocarbon production, which tends to be much greater per volume of produced water than older wells. It is unlikely that plans to drill BAT wells will be curtailed because of effluent guidelines requirements, given the large number of coastal wells currently injecting produced water. Barriers to entry for NSPS wells are addressed separately in Section Ten.

5.1 DESCRIPTION OF THE ECONOMIC MODEL FOR COOK INLET, ALASKA

To estimate the effects of the regulatory approaches being considered, the economic performance of projects is simulated before and after complying with new pollution control requirements, as discussed above. The following discussion uses the terms "baseline" and "postcompliance" scenarios to describe the two phases of analysis. This section reviews the economic model and its components for Cook Inlet, Alaska, production platforms.

Fifteen platforms are located in Cook Inlet and all are in the coastal subcategory of the oil and gas extraction point source subcategory. Thirteen of these platforms are currently productive, although fourteen are included in the Cook Inlet model analysis (drilling is planned at Spark, which is currently shut in). Phillips operates one platform (Tyonek A), Shell Western operates two that send production to the East Forelands facility (SWEPI A and SWEPI C), and Marathon/UNOCAL operates four platforms (Anna, Baker, Bruce, and Dillon) and two facilities (Granite Point, with platforms Granite Point and Spark; and Trading Bay, with platforms Dolly Varden, Grayling, King Salmon, Monopod, and Steelhead). Marathon/UNOCAL has suspended production at another platform (Spurr), and since no drilling is planned, it is not included in the analysis. ARCO's Sunfish project is uncertain, and it is unlikely that a platform will be constructed (Personal communication between Allison Wiedeman, EPA, and Jim Short, ARCO, May 9, 1994).[2] Refer to Figure 3-2 in Section Three for a detailed map of the platforms in Cook Inlet.

5.1.1 Economic Model Overview

The production loss model simulates the performance and measures the profitability of a petroleum production project. For the Cook Inlet region of the coastal subcategory, a project is defined as a single platform or island. All projects used in the Cook Inlet model currently exist and are modeled starting in productive midlife (i.e., not including costs of exploration and

[2]Regulatory costs associated with this project are included in cost estimates, but impacts are not analyzed.

development). For each project, modeling inputs include production and operations cost data, typical production rates, oil and gas selling prices, continuing drilling schedules and costs, and other pertinent data. Platform-specific drilling on existing structures and associated increases in production also are considered. For each project, the model calculates the annual posttax cash flow for each year of operation as well as cumulative performance measures, such as net present value (NPV)[3] and total lifetime petroleum production.

The schematic design of the model is summarized in Figure 5-1. Three sets of exogenous values are entered into the model: general model variables (Table 5-1), project-specific variables (Table 5-2), and pollution control costs (discussed in Section Four).

The model provides calculation procedures and algorithms that duplicate (1) the oil industry's standard accounting procedures, (2) federal taxation rules enacted by the Tax Reform Act of 1986, and (3) standard financial rate-of-return calculation methods. The outputs of the economic model are a series of yearly project cash flows and cumulative performance measures.

The regulatory approaches are incorporated into the economic model by adding relevant capital costs and operating expenses to the set of cost data. The model calculates all yearly and cumulative outputs for both the baseline case and regulated cases for each project. When the results of these two scenarios are compared (external to the model itself), the incremental effects of regulation can be discerned.

5.1.2 Model Parameters

A distinct set of parameter values is required for each of the platforms modeled; each set constitutes a complete economic description of the project. The following categories of parameters are incorporated into the model for each project:

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[3]NPV is the present value of a stream of net income from baseline year to the end of the well's economic life (defined to end when operating costs, including pollution control costs, exceed revenues), discounted annually by the real discount rate.

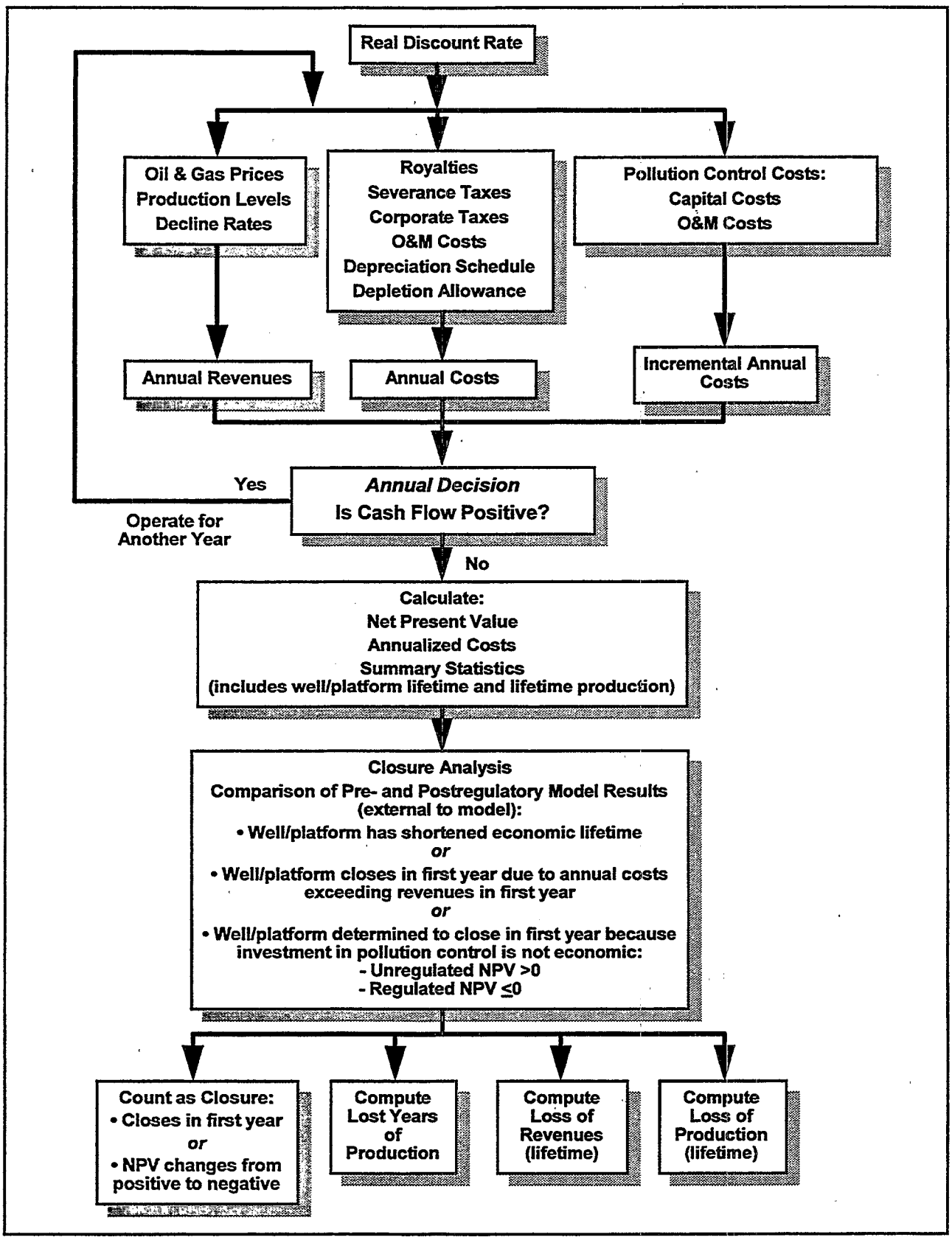

Figure 5-1. Overview of closure analysis methodology.

TABLE 5-1

COOK INLET PRODUCTION LOSS MODEL: COMMON PARAMETER VALUES

Parameter	Value	Source
Real discount rate	8.0%	Offshore EIA (U.S. EPA, 1993b).
Inflation rate	3.0%	1993 Statistical Abstract of the United States, 1992 data.
Corporate tax rate	34.0%	Federal Tax Bracket.
State severance tax - oil	$0.05/bbl	Production tax surcharge of $0.05/bbl. Economic Limit Factor, revised in 1989, takes into account field size. Cook Inlet platforms have not paid oil severance tax for several years (Logsdon, 1994).
State severance tax - gas	varies	Economic Limit Factor, see Offshore EIA.
Percent of expensed intangible drilling costs	42.0%	Major operators may expense 70 percent of intangible drilling costs (IDCs). IDCs are estimated at 60 percent of drilling costs. (U.S. EPA, 1993b).
Annual production decline rate	8.0%	Marathon Oil Co./UNOCAL, Zero Discharge Analysis, presented to EPA, March 24, 1994, Produced water section, page 10.
Initial well production rate (bpd)	500	Marathon Oil Co./UNOCAL, Zero Discharge Analysis, presented to EPA, March 24, 1994, Drilling wastes section, page 26. Used for new and recompleted wells.
Initial well production rate (Mcf/d)	15,000	Average of Steelhead and Tyonek A per-well production. AOGA presentation to EPA, 29 October 1991.
Well cost - new ($000)	$4,065	Zero-Discharge Compliance Cost Estimates for Drilling Wastes in Cook Inlet, Alaska, Coastal Oil & Gas Operations, Memorandum to Allison Wiedeman, EPA, from Behzad Safavi, 9 May 1994, Worksheet 1. Average drilling cost for wells drilled in Cook Inlet in 1992 (survey data), sum of columns 24-26.
Well cost - recompletion ($000)	$1,360	Zero-Discharge Compliance Cost Estimates for Drilling Wastes in Cook Inlet, Alaska, Coastal Oil & Gas Operations, Memorandum to Allison Wiedeman, EPA, from Behzad Safavi, 9 May 1994, Worksheet 1. Average drilling cost for wells drilled in Cook Inlet in 1992 (survey data), column 26.
Wellhead price - oil ($/bbl)	$14.50	Marathon Oil Co./UNOCAL, Zero Discharge Analysis, presented to EPA, March 24, 1994, Produced water section, page 7; comparable to range seen within survey data.
Wellhead price - gas ($/Mcf)	$1.57	Scaled from oil price (10.8 percent, see U.S. EPA, 1993b, Table 5-20); comparable to survey data.

TABLE 5-2

COOK INLET PRODUCTION LOSS MODEL: SUMMARY OF PLATFORM DATA AND INPUTS

Platform	Owner	Treatment Facility	Oil Prouction 1991 data bpd	Oil Prouction 1992 data bpd	Oil Prouction 1993 data bpd	Oil Prouction Estimated 1996 bpd	Gas Production 1991 data Mcf/day	Gas Production 1993 data Mcf/day	Gas Production Estimated 1996 Mcf/day	Estimated Operating Costs ($000)	Later Operating Costs ($000)	Royalty Oil	Royalty Gas
SWEPI A	Shell Western	E. Foreland	3,100	3,453	2,700	2,102	0	0	0	$6,899		12.5%	0.0%
SWEPI C	Shell Western	E. Foreland	3,000	3,169	2,400	1,869	0	0	0	$6,132		12.5%	0.0%
Granite Point	UNOCAL	Granite Point	2,600	2,392 *	4,300	3,348	0	0	0	$10,987		11.1%	0.0%
Spark	Marathon	Granite Point	300	276 *	suspended	198	0	0	0	$705	$3,833	12.7%	0.0%
Dolly Varden	Marathon	Trading Bay	6,700	7,223	6,500	5,061	0	0	0	$16,608		12.7%	0.0%
Grayling	UNOCAL	Trading Bay	6,800	6,705	7,600	5,918	0	0	0	$19,418		11.1%	0.0%
King Salmon	UNOCAL	Trading Bay	5,000	4,600 *	4,100	3,193	0	0	0	$10,476		11.1%	0.0%
Steelhead	Marathon	Trading Bay	2,000	1,840 *	1,800	1,402	165,000	165,000	128,484	NA		12.7%	12.0%
Monopod	UNOCAL	Trading Bay	2,800	2,576 *	2,000	1,557	0	0	0	$5,110		11.1%	0.0%
Baker	UNOCAL	Platform	1,000	920 *	1000	779	0	0	0	$2,555	$3,833	11.1%	0.0%
Dillon	UNOCAL	Platform	400	368 *	suspended	264	0	0	0	$940	$3,833	11.1%	0.0%
Anna	UNOCAL	Platform	2,700	2,484 *	2,300	1,791	0	0	0	$5,877		11.1%	0.0%
Bruce	UNOCAL	Platform	600	419	600	467	0	0	0	$1,533	$3,833	11.1%	0.0%
Tyonek A	Phillips	Platform	0	0	0	0	165,000	165,000	128,484	NA		0.0%	12.0%

Notes: Spurr has no production, and no drilling is planned.
Annual decline rate of 8.0%
1996 production estimated by declining 1993 production except for Dillion and Spark. For those platforms, 1991 data were declined.
Except for Tyonek A and Steelhead, all gas produced is assumed to be consumed at the platform.
Operating costs based on 1993 production (bbl or boe), unless later wells or recompletions result in higher production rate.
Operating costs based on estimated cost of $7.00/bbl
NA: not available due to confidentiality of survey data.
*: estimated

Sources: AOGA 1991, 1993
1992 data: 308 Survey data (non -confidential).

- *Drilling cost per well.* Costs for both new production wells and recompletions.
- *Drilling schedule.* Schedule from 1996 to 2002, detailing platform-specific drilling activity for new production wells and recompletions (see Table 4-3 in Section Four).
- *Production rates per platform.* Initial production rates of oil and gas and production decline rates.
- *Operation and maintenance costs per platform* (estimated as a per BOE cost).
- *Incremental pollution control costs* (estimated as a per BOE cost for the post-compliance scenario only).
- *Tax rates.* Rates for federal and state income taxes, severance taxes, royalty payments, depreciation, and depletion.
- *Price.* Wellhead selling price of oil and gas (also called the "first purchase price" of the product).

The parameter values used in the analysis are summarized in Table 5-1 and described more fully in Appendix A.

5.1.3 Model Calculation Procedures

The model's calculation procedures are a set of rules and logic used to convert the project parameters into measures of a project's financial performance. These procedures fall into several categories.

5.1.3.1 Production Logic

The model equations use exogenous values for peak production rates and production decline rates to define a production profile for each platform. The model includes current production as well as production increases attributable to new wells and recompleted wells brought online. Summary measures of production for the entire project lifetime are also calculated.

5.1.3.2 Cost Logic

The model equations use exogenous cost data to define the yearly capital and operating costs of each project. Exogenous parameters include drilling capital costs as well as production (including existing pollution control costs) and drilling operating costs. Using the model sequencing logic, the exogenous cost information is converted to annual capital and operating cost streams. Summary measures of all capital and operating costs are calculated for the entire project lifetime.

5.1.3.3 Incremental Pollution Control Cost Logic

A set of equations incorporates the capital and operating costs of additional pollution control approaches into the project cost stream, thus, creating a simulation of the economic effect of alternative regulatory approaches. These pollution control costs can include capital and operating costs for disposal of produced water and drilling wastes. For regulated cases, the model incorporates both capital and operational pollution control costs. Pollution control capital costs are incurred in the base year (1996) and a portion is expensed (with the remainder capitalized). Capital costs for new wells are incurred in the year they are drilled and a portion is expensed as well.[4] Pollution control operating costs are analyzed in the same way as other operating costs for the project.

5.1.3.4 Cost Accounting Practices

Specialized oil industry accounting procedures are applied to project cost streams. Capital and operating costs are analyzed in accordance with oil industry accounting practices. The model calculates the expensed and capitalized portions of each capital expenditure, which in turn are used as a base to estimate depreciation for each year of the project's lifetime.

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[4]Note that pollution control costs for Gulf wells are handled differently (see Section 5.2).

5.1.3.5 Price and Revenue Calculations

The wellhead prices of oil and gas are exogenous parameters in the model. The prices are multiplied by the annual production volumes to calculate annual project revenues. Revenues are calculated both as an annual stream and as a present-value-equivalent total for the project's lifetime. The wellhead prices are presented along with other data in Table 5-1.

5.1.3.6 Earnings and Cash Flow Analysis

The model calculates a project's annual earnings (i.e., the difference between a project's revenues and its costs). Severance tax and royalty payments are subtracted from earnings before corporate taxes are removed to calculate annual cash flow. Depreciation and depletion are treated in these calculations according to federal laws (see Appendix A). Severance taxes on oil and gas production in Cook Inlet are calculated using an Economic Limit Factor (ELF), described in Appendix A. Tax rates and royalty rates are presented in Table 5-1.

5.1.3.7 Financial Performance Calculations

A variety of summary financial measures are calculated in the model. Annual project cash flows are discounted to the present using an 8 percent discount rate to calculate the NPV of the project. The 8 percent discount rate is the rate used in the offshore EIA (EPA, 1993a) and the average reported by all Section 308 survey respondents (EPA, 1993b). In addition, lifetime petroleum production (on a total and present value basis), total revenues, total costs, and years of production are summarized. The present value of all project costs is divided by the present value of all petroleum production to calculate the average cost per unit of production.

The specifics of each of these calculations are given in more detail in Appendix B, which describes the Cook Inlet production loss model.

5.1.4 Interpretation of Model Results

Based on the economic model logic described above, a number of summary statistics and performance measures are calculated for each project, including:

- NPV of the project.
- Total lifetime production.
- Present value equivalent of production.
- Total years of production.
- Economic viability of the project (first-year closure).
- Present value of all project costs.
- Present value of all project revenues.
- Present value of additional pollution control costs.
- Present value of severance tax payments.
- Present value of corporate income tax payments.
- Present value of royalties.
- Corporate cost per unit of production.
- Production cost per unit of production.

The analysis of the economic status of the baseline case (presented in Section 5.2) focuses on the first few parameters listed above as performance measures. The analysis of regulated cases includes comparisons between the base case statistics and regulated case results.

The *net present value* is calculated as the difference between the present values of all cash inflows and all cash outflows associated with a platform (from the perspective of the firm). A positive value indicates that a project generates more revenues than would be realized by investing the capital elsewhere in a different opportunity with an expected rate of return equal to the cost of capital used in this analysis.

Total lifetime production sums the stream of future petroleum production.

The *present value equivalent of production* is defined as the value of the discounted stream of future petroleum production.

Total years of production is calculated as the number of years the project will operate with a positive cash flow. The model can estimate annual cash flows over a 30-year lifetime. The model assumes that a platform will stop producing when cash flow is negative (i.e., when current variable costs exceed current revenues).[5]

The *corporate cost* per unit of production is defined as the present value of all net corporate cash outflows for the project life (i.e., the cost of operation, royalties, severance tax and income tax payments, with adjustments made for tax savings based on depreciation and depletion) divided by the present value of all production (e.g., BOE of oil and gas production). The present value calculations use a cost-of-capital interest rate of 8 percent to discount costs, cash flow, and production. If the corporate cost per unit of production is lower than the projected wellhead selling price, the project is considered viable.

The *production cost* per unit of production is a measure of the value of net social resources expended in operation of coastal petroleum projects. In contrast to the corporate cost, the production cost ignores the effect of transfers that do not use social resources, such as income taxes, revenue taxes, and royalties. The present values of all investment costs and operating costs are included in the calculation of this cost. The sum of these costs is divided by the present value equivalent of production to obtain production costs.

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[5]In Cook Inlet, variable costs are the baseline operating costs plus (in postcompliance scenarios) the O&M cost component of pollution control costs. Fixed costs do not play a role in the production decision. In the Gulf, however, for simplicity, capital costs for compliance equipment are annualized and added to O&M costs of compliance to compute a cost per barrel of produced water disposed. These costs become variable costs, much as if the facility were operating on a commercial basis (see Appendix C).

5.1.5 Parameter Values and Data Sources

For all Cook Inlet platforms, previously expended costs (e.g., of leasing, exploration, delineation, and platform installation) are considered sunk costs. All modeling uses a set of common parameter values (summarized in Table 5-1). All costs are assumed to be in 1992 dollars (or are deflated/inflated to 1992 dollars), and year 1 in the model is 1996, the year the regulation is assumed to go into effect. Although the regulation is not expected to be promulgated until late 1996, partial years cannot be modeled for impacts. Thus, to be conservative, the model reflects cost increases at the beginning of 1996.

5.1.5.1 Drilling Schedule and Drilling Cost per Well

The planned drilling programs in Cook Inlet are summarized in Section Four (see Table 4-3). Drilling is projected to occur from 1996 through 2002, with no drilling planned for 1999 or 2001. The economic model for each platform has been modified to reflect the costs for the new and recompleted wells in the baseline case (that is, the economic profile of platforms before compliance cost are incurred).

Several assumptions were made in developing the drilling schedule from the information submitted to EPA by the Cook Inlet operators. The assumptions are as follows:

- The regulation takes effect in 1996.
- Wells that are planned to be drilled in a time window that includes 1996 are assumed to be drilled in 1996 (e.g., if a drill date possibility spans 1994-1996, the well is assumed to be drilled in 1996).
- All other wells are drilled in the earliest possible years after 1996, given their planning window (e.g., if the well is to be drilled sometime between 1997 and 1999, the well is assumed to be drilled in 1997), with one exception. Since no more than four rigs are available at any one time to Marathon/UNOCAL, and assuming a 3-month drill schedule, a maximum of 16 wells can be drilled in any one year. Based on the above assumptions, too many wells would be scheduled for 1996. Thus, one group of three wells drilled on the Monopod platform was arbitrarily assigned to 1997 (the time window for drilling on this platform spanned 1995-1998).

The model differentiates drilling costs between new production wells and recompletions. Drilling costs for new wells include costs to drill three segments of a well. Recompletion costs include costs to recomplete the third segment of a well. Section 308 survey data estimated a per-well cost for new production wells at $4.1 million and the cost for recompletions at $1.4 million (SAIC, 1994). It is assumed that the oil company elects to expense intangible drilling costs (IDCs) incurred in the development of oil and gas wells. IDCs are estimated, on the average, to represent 60 percent of the cost of production wells and their infrastructure (Commerce, 1982; Commerce, 1983; API, 1986). The Tax Reform Act limits major integrated oil producers to expensing 70 percent of IDCs with the remaining 30 percent capitalized (that is, a major may only expense 0.60 times 0.70, or 42 percent of its costs of production wells and infrastructure). The remaining 58 percent of the total cost of production wells and infrastructure is capitalized and treated as depreciable assets for tax purposes (Snook and Magnuson, 1986). It is important to note that these capital costs can be depreciated using the Modified Accelerated Capital Recovery System (MACRS) over a 7-year period (see Appendix A). The capital cost is taken into account with present value modifications once all depreciation and tax shield benefits are accounted for by the model.

5.1.5.2 Production Rates

Production rates for the Cook Inlet platforms were available for three years: 1991 and 1993 data are taken from the information provided to EPA by the Alaska Oil and Gas Association (AOGA), and 1992 data are taken from the Coastal Oil and Gas Questionnaire (AOGA, 1991; AOGA, 1993; EPA, 1993a). Since the 1993 data are the most recent that are available and, thus, reflect increased production from recent drilling efforts, they are used as the basis for estimating production in 1996. The exceptions are Dillon and Spark, which had production suspended in 1993; 1991 production levels were used to estimate production in 1996. Based on survey responses, all platforms except Steelhead and Tyonek A are assumed to consume all gas produced at the platform.

5.1.5.3 Baseline Operation and Maintenance Costs per Platform

For oil-producing platforms, the annual operating cost is estimated as the product of 1993 production rates and a per-barrel operating cost of $7/bbl. This figure was estimated by working with the model to approximate baseline projections provided by Marathon/UNOCAL (1994b). It falls within the range for this figure reported by Marathon/UNOCAL (1994a).

For four platforms—Spark, Baker, Dillon, and Bruce—additional operating costs begin when new or recompleted wells result in substantial production increases. The current oil and water volume handled by treatment facilities serving these platforms would be increased by an additional flow 2 to 7.5 times the current flow. We assume that such an increase would result in additional operating costs to process the produced fluids. The additional annual operating cost per platform is based on the product of the initial daily production for a new or recompleted well (500 bpd), the initial number of wells drilled per platform (3 wells for each of Spark, Baker, Bruce, and Dillon in 1996 or 1997), the number of days of operation per year (365), and the per-barrel production costs ($7, as discussed above). The formula is as follows:

$$\begin{matrix}\text{initial daily}\\ \text{production}\\ \text{per well}\end{matrix} \times \begin{matrix}\text{number}\\ \text{of wells}\end{matrix} \times \begin{matrix}\text{days per}\\ \text{year}\end{matrix} \times \begin{matrix}\text{per-barrel}\\ \text{production}\\ \text{costs}\end{matrix}$$

or

$$500\ \frac{\text{bpd}}{\text{well}} \times 3\ \text{wells} \times 365\ \frac{\text{days}}{\text{year}} \times \frac{\$7}{\text{bbl}} = \$3{,}832{,}500$$

One of the four platforms was investigated in more detail and the per-barrel production costs were re-estimated using other information from the model. This information is detailed in an ERG memorandum (ERG, 1994).

For gas-producing platforms, annual operating costs are based on Section 308 survey data (EPA, 1993a).

5.1.5.4 Tax Rates

The tax rates used in the model include federal corporate tax rates, severance taxes, and royalty payments. The federal corporate tax rate is 34 percent and is applicable to all Cook Inlet operators. Severance taxes were calculated using the ELF. The Alaska Department of Revenue reports that oil wells in Cook Inlet have not incurred severance taxes for several years (see Appendix A for more information).

Royalties are based on nonconfidential survey data. The same royalty rates are applied to all platforms with the same ownership (e.g., all Marathon platforms have an 11.1 percent royalty on oil production). Royalty rates are presented in Table 5-2 for each of the platforms.

Depreciation for capital expenditures is based on MACRS (details are provided in Appendix A). For major oil companies, depletion applies to allocation of leasehold costs. Because the model assumes all prior investments to be sunk, no basis exists for estimating depletion for the major oil companies operating in Cook Inlet. This omission leads to a slight underestimate of the profitability of each project in the baseline analysis but has little to no effect on the incremental impact analysis.

5.1.5.5 Prices

The wellhead price of oil and the wellhead price of gas are presented in Table 5-1. The value for oil is taken from Marathon/UNOCAL (1994b), in their Zero Discharge Analysis, and is $14.50 per barrel, an estimated price for 1992 production. Average rates from the Coastal Oil & Gas Questionnaire survey database are comparable. The wellhead price of gas is scaled from the price of oil and taken as 10.8 percent of the oil price (U.S. EPA, 1993a). The price of $1.57/Mcf is comparable to data from the Coastal Oil & Gas Questionnaire (U.S. EPA, 1993a).

5.1.6 Calculation Procedures

5.1.6.1 Production Logic

To determine production at a platform, the model begins production estimates in 1996, using the production rate estimated above. It is assumed that peak production rates occur in the first year of production and are maintained for the first year only. The pattern of decline in a well's productivity can vary greatly due to many factors. Production decline is modeled as an exponential function (i.e., a constant percentage of the remaining reserves produced in any given year). This production is assumed to decline by 8 percent annually, a value taken as typical for Cook Inlet (Marathon/UNOCAL, 1994b). Gas production at the two platforms that do not consume their gas onsite is also declined at this 8 percent rate. These two values are combined into a BOE figure.

Increases in production originating with recompleted or new production wells are also included. When a company drills new wells or recompletes existing wells, corresponding increases in production at a rate of 500 barrels of oil per day (Marathon/UNOCAL, 1994b) or 15,000 Mcf gas per day (AOGA, 1991) are included.

5.2 DESCRIPTION OF THE ECONOMIC MODEL FOR THE GULF OF MEXICO

Although the model for the Gulf of Mexico is similar to the model used for Cook Inlet—indeed the methodology is the same—there are some basic differences, which are described below. A line-by-line description of the Gulf of Mexico production loss model is provided in Appendix C.

5.2.1 Economic Model Overview

The Gulf of Mexico model analyzes the effects of regulations on individual wells (rather than platforms as in Cook Inlet) that discharge produced water in the coastal subcategory.

These wells discharge produced water through a permitted treatment facility. Unlike the Cook Inlet model, the Gulf of Mexico model focuses on the well level and is used to investigate the effects of the regulation on the productive lifetime of the well. Whereas the Cook Inlet model estimates increases in production at a platform resulting from the addition of new production wells and recompleted wells drilled over the first 7 years after the regulation is established, the Gulf of Mexico model assumes no increase in production at the well level.

Incremental costs for produced water disposal are based on engineering costs that would be incurred by a production facility complying with the regulation (see Section Four for information on compliance costs). As noted in Section 5.1.4 (footnote), incremental compliance costs are handled somewhat differently from the Cook Inlet model. For simplicity (because information on each well served by each affected facility is not available, as it is in Cook Inlet), pollution control capital costs are annualized over a 10-year period at a discount rate reported by the respondent in the Section 308 survey or the survey average of 8 percent (if data are missing) and are added to the operating and maintenance costs to determine an annual cost. This cost is divided by the total permitted discharge volume of the treatment facility to establish a per-barrel cost that can be applied to the volume of produced water that each well generates.

For the Gulf of Mexico model, each well was assumed to produce a constant volume of oil and water combined over its lifetime. As the volume of oil produced declines at an exponential rate, water production increases proportionally. This ever-increasing water production increases annual compliance costs each year.

Most data for the individual wells are taken from Section 308 survey responses. For missing data or outliers, average values from the survey were substituted for the questionable or missing value (see Appendix A).

Both major oil companies and independent producers own wells that are analyzed in the Gulf of Mexico production loss model. Although the two types of owners can deduct depletion from income, they would use different methods. A major oil company must use the cost basis for depletion, in which the lease cost is deducted over the production lifetime according to the

proportion of the reserves sold that year. Since the BAT model assumes all costs prior to model year 1 are sunk costs, annual depletion is $0.

Independent producers have the option of using percentage depletion. The company is allowed to write off 15 percent of taxable revenues up to and including 1,000 bpd or 6,000 Mcf per day of production. The Gulf of Mexico model assumes that independent producers will select this method of depletion and reap the benefits associated with it. The two methods of depletion are discussed further in Appendix A.

Wells in the Gulf of Mexico production loss model that discharge produced water are taken from a stratified sample of all wells operating in the Gulf. Once individual well results are obtained, the results are weighted according to the stratum in which the well was classified. Results are further adjusted to take into account the estimate of wells drilled prior to 1980 that are believed to be associated with facilities that will be discharging in 1996 (see Section Three and detailed discussion in 5.3.1.1). Thus, the results of the production loss model represent the estimated population of coastal dischargers in the Gulf of Mexico region.

5.3 PRODUCTION LOSS MODELING RESULTS

This section presents the results of the production loss modeling for Gulf of Mexico wells and Cook Inlet platforms. Results are organized into baseline modeling results and postcompliance modeling results and broken down by region. Postcompliance results include numbers of first-year shut-ins of wells or platforms by option, production losses, years of production lost, net present dollar value of production losses, and state and federal revenues lost. Section 5.3.1 presents the results of Gulf of Mexico modeling, Section 5.3.2 presents the results of Cook Inlet modeling for produced water and drilling waste, and Section 5.3.4 presents the combined results of Gulf of Mexico and Cook Inlet modeling for produced water regulatory options. Section 5.3.4 summarizes the total impacts of all the selected regulatory options, and Section 5.3.5 briefly discusses expected impacts from TWC options.

5.3.1 Gulf of Mexico

5.3.1.1 Baseline Modeling Results

Option #1—Produced Water

The estimate of the number of wells that are predicted to be associated with facilities discharging in 1996 when based directly on the section 308 survey (after all facilities on compliance schedules are removed from the analysis) is 131. When this number is adjusted by the overall factor of 1.61 used to determine the total number of wells in the Gulf coastal area (i.e., Louisiana and Texas), a total of 211 discharging wells results, which is only about 1 well per discharging facility (216 facilities—see Section Three). This estimate is considered unrealistic and might be caused by the possibility that a large portion of all estimated discharging pre-1980 wells are associated with discharging facilities that will continue to discharge in 1996.

Consequently, an alternative estimate of wells was derived, based in part on the approach used to calculate the total number of wells in the Gulf coastal region (including pre-1980 wells). It is estimated that 216 facilities will be discharging in 1996. The number of wells served on average by discharging facilities in 1996 is estimated using survey data to be 7.35 wells per facility. Therefore, the total number of wells discharging in 1992 associated with facilities that will continue to discharge in 1996 is estimated to be 1,588 wells.

Model results are extrapolated based on the 1,588 productive wells estimated to be discharging in 1996. According to the baseline analysis, using data provided for wells in the survey on total production, wellhead price, and an estimate for production costs, 195 of these wells are estimated to be not economical to produce (and very likely, in fact, have been shut in since the survey was performed). Thus, 1,393 wells are estimated to be operating and continuing to discharge in 1996; the number of wells discharging in 1996 is estimated to be 30 percent of the total 4,675 productive Gulf of Mexico wells.

The total lifetime production of the 1,393 discharging wells (calculated over a maximum 30-year span) is 253.8 million BOE in present value terms or 354.2 million total BOE.[6] The total productive lifetime of these wells is 24,447 years, or an average of 15.4 years per well (including baseline shut ins). The net present value of this production, based on an assumption of constant real wellhead price is $1.2 billion (see Table 5-3 for a summary of baseline data). As discussed in Section Three, total lifetime production in the Gulf of Mexico (Texas and Louisiana) is expected to range between 692.5 million BOE and 1,391.2 million discounted BOE, and the net present value (i.e., the present value of producer net income) ranges from $10.6 billion to $21.3 billion. Thus, baseline production associated with discharging wells is estimated to be 5.6 percent to 11.3 percent of the total net present dollar value to the producer of total Gulf of Mexico production and 18 to 37 percent of the Gulf's total lifetime discounted production.

The total present value of federal and state income tax collected over the economic lifetime of the discharging wells is projected to be $600.6 million or approximately, on average, $70.2 million annually.[7] The present value of severance tax collected over the lifetime of the discharging wells is expected to be $223.3 million or about $26.1 million, on average, per year. Additional royalties (present value) paid to the states (and others) are estimated to be $413.9 million, or $48.4 million on average annually. Total state revenues over the lifetime of these discharging wells are, thus, estimated at $637.2 million, or $74.4 million annually, on average.[8]

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[6]Barrels of oil equivalent represents the total oil and gas produced, with gas converted to an equivalent measurement based on the amount of energy in a cubic foot of gas and the number of cubic feet of gas needed to match the energy in a barrel of oil. The present value of BOE reflects BOE discounted to the present under the assumption that a barrel of oil today is worth more than a barrel of oil in the future. It is a useful measure to compare with other present value figures.

[7]Present value annualized over the average baseline lifetime of wells in the Gulf (approximately 15 years).

[8]For simplicity in this section, royalties are assumed to be paid primarily to the states, although in the Gulf, some royalties are paid to individuals. In Cook Inlet, all royalties are paid to the state.

TABLE 5-3

RESULTS OF THE PRODUCTION LOSS MODELING IN THE GULF REGION
(Produced Water, 1992 $)[a]

	Baseline	Improved Gas Flotation	Zero Discharge
Productive wells in analysis	1,588	1,588	1,588
Total first-year shut-ins	195	237	306
Postcompliance first-year shut-ins	—	42	111
Total wells remaining in analysis	1,393	1,351	1,282
Lifetime discounted production (BOE)	253,785,398	244,368,043	241,723,591
Change in lifetime discounted production (BOE)	-	9,417,355	12,061,807
Percentage change	-	3.7%	4.8%
Total projected lifetime production (BOE)	354,179,441	331,185,521	326,421,312
Change in total lifetime production (BOE)	-	22,993,920	27,758,129
Percentage change	-	6.5%	7.8%
Total production lifetime (years)	24,447	16,758	15,197
Change in production lifetime	-	7,689	9,249
Percentage change	-	31.5%	37.8%
Average lifetime (years)	15.4	10.6	9.6
Change in average lifetime	-	4.8	5.8
Percentage change	-	31.2%	37.7%
Present value of producers' net income (NPV) ($000)	1,183,255	1,077,333	1,038,775
Change in NPV ($000)	-	105,922	144,480
Percentage change	-	9.0%	12.2%

TABLE 5-3 (cont.)

	Baseline	Improved Gas Flotation	Zero Discharge
Present value of federal and state income tax collected ($000)	600,626	544,559	520,975
Change in income tax collected ($000)	-	56,068	79,651
Percentage change	-	9.3%	13.3%
Present value of severance tax collected ($000)	223,267	217,835	212,750
Change in severance tax collected ($000)	-	5,433	10,517
Percentage change	-	2.4%	4.7%
Present value of royalties collected ($000)	413,925	398,114	384,867
Change in royalties collected ($000)	-	15,810	29,058
Percentage change	-	3.8%	7.0%

*Baseline reflects values for discharging wells only. Total Gulf coastal baseline figures would be much greater in most categories.

Note: Results are weighted using well survey weights and adjustment factors noted in the text.

Source: ERG estimates.

5.3.1.2 Postcompliance Production Loss

Option #2—Produced Water

When the compliance costs associated with installing and operating improved gas flotation systems are added to the baseline operating costs for the model wells, 42 wells are estimated to shut in immediately in response to the regulation incremental to those that close in the baseline.

These 42 first-year shut-ins and reduction in the economic lifetime of discharging wells lead to declines in production totaling 9.4 million discounted BOE (23.0 million total BOE) over the remaining life of the wells, or a decline of 3.7 percent among the discharging wells. Lifetime production loss is expected to range between 0.7 percent and 1.4 percent of total estimated Gulf of Mexico lifetime production (present value). The net present dollar value of this production loss to producers totals $105.9 million ($15.8 million annually), or 9.0 percent of the net present value of producers' income projected for discharging wells. This loss is only 0.5 to 1.0 percent of the net present value of producers' income among all Gulf of Mexico (Louisiana and Texas) wells.

The total number of well years of productive life lost is 7,689, which is 31.5 percent of all years estimated to remain among discharging wells in the baseline. Since average lost productive life is 4.8 years, average postcompliance life is 10.6 years among discharging wells. Note that production losses are a far lower percentage of discharging well production than years lost; thus, a considerable portion of the production losses is likely to be associated with marginal wells that might have a number of years of production remaining but that produce relatively little oil or gas.

The total present value of the lifetime loss of federal and state income tax is estimated to be $56.1 million ($8.4 million lost per year on average over the approximately 10 years of average well lifetime remaining). This loss is 9.3 percent of the total present value of income tax expected to be collected from discharging Gulf of Mexico wells over their productive lifetime, nearly all of which is federal income tax.

The total present value of the loss of state severance taxes over the life of the discharging wells is estimated to be $5.4 million or $0.8 million annually on average, or 2.4 percent of the present value of severance tax receipts in the baseline from discharging wells over their productive lifetimes. Royalties lost are estimated to total $15.8 million ($2.4 million annually, on average), for a total present value loss to the states (in severance and royalties) of up to $21.2 million over the productive lifetime of the discharging wells ($3.2 million annually).

Table 5-3 summarizes the impacts of the improved gas flotation option on Gulf of Mexico discharging wells.

Options #3, #4, and #5—Produced Water

When the compliance costs associated with meeting zero discharge requirements in the Gulf for produced water are added to the baseline operating costs for the model wells, 111 wells are estimated to shut in immediately in response to the regulation incremental to those that close in the baseline.

These first-year shut-ins and reduction in the economic lifetime of discharging wells lead to declines in production totaling 12.1 million discounted BOE (27.8 million total BOE), or a decline of 4.8 percent among the discharging wells (present value). Lifetime production loss is expected to range between 0.9 and 1.7 percent of total estimated lifetime production in the Gulf. Producers lose $144.5 million in net present value of income ($21.5 million annually), or 12.2 percent of their projected net present value. This loss is only 0.7 to 1.4 percent of the projected net present value of income among all Gulf of Mexico operators.

The total number of well years of productive life lost is 9,249, which is 37.8 percent of all years estimated to remain among discharging wells in the baseline. Since average lost productive life is 5.8 years, average postcompliance life is 9.6 years among discharging wells. Note that production losses are a far lower percentage of discharging well production than years lost; thus, a considerable portion of the production losses is likely to be associated with marginal wells that

might have a number of years of production remaining but that produce relatively little oil or gas.

Total loss (in present value) of federal and state income tax is estimated to be $79.7 million over the productive life of the discharging wells ($11.9 million, on average, annually over the approximately 10 years of average well lifetime remaining), which is 13.3 percent of the total federal and state income tax (nearly all federal) expected to be collected from discharging Gulf of Mexico wells over their productive lifetime.

The total present value loss of state severance taxes is estimated to be $10.5 million over the productive life of the discharging wells ($1.6 million, on average, annually), or 4.7 percent of severance tax receipts in the baseline from discharging wells. The total present value of royalties lost is estimated to total $29.1 million (or $4.3 million, on average, annually), for a total present value loss to the states (in severance and royalties) of up to $39.6 million over the productive life of the discharging wells ($5.9 million annually).

5.3.2 Cook Inlet

5.3.2.1 Produced Water

Baseline Analysis Results (Option #1 and #3)

Currently in Cook Inlet 14 platforms are either operating or are projected to be operating (i.e., the operator has plans for drilling). These 14 platforms, none of which close in the baseline, are estimated to produce 198.1 million discounted BOE (306.9 million total BOE) over the lifetime of these platforms without any further regulatory action. The net present value of producer income (i.e., the present value of their projected net income stream) of this lifetime production is $416.2 million ($62.0 million annually). These platforms are estimated to operate for a total of 156 platform-years, or 11.1 years on average. The present value of severance taxes collected totals an estimated $60.3 million ($8.4 million, on average, annually over the 11 years of platform lifetime remaining), the present value of royalties to the state total $264.1 million

($37.0 million, on average, annually), and the present value of federal income taxes collected are projected to total $241.0 million ($33.8 million, on average, annually) (see Table 5-4).

Option #2 and #4 Results

Both Option #2 and #4 require offshore limits to be met (i.e., improved gas flotation) among the Cook Inlet platforms. Use of improved gas flotation has the following effects on production in the Cook Inlet: No platforms are projected to shut in during the first year. Total lifetime production in Cook Inlet drops by 3.1 million discounted BOE to 195.0 million discounted BOE (a loss of 4.6 million total BOE). This reduction is 1.6 percent of lifetime discounted production in the Cook Inlet. Producers' net present value drops $8.7 million to $407.5 million ($60.7 million annually). This net present value loss is 2.1 percent of baseline projected net present value among Cook Inlet producers. Average production years per platform drop from 11.1 to 10.7 years, thus, the installation and operation of improved gas flotation will result in platforms shutting in an average of 5 months earlier than they would have without the regulation.

The total present value of lifetime federal income taxes lost under this option are estimated to be $5.3 million ($0.7 million, on average, annually over the 11-year life of platforms estimated under this option), or 2.2 percent of the baseline federal taxes estimated to be collected over the life of the platforms. The present value of severance taxes lost total $159,000 over the life of the platforms ($22,000, on average, annually). Royalties lost to the state total $5.2 million over the life of the platforms ($0.7 million, on average, annually), or 2.0 percent of the baseline royalties collected (see Table 5-4).

Option #5 Results

Option #5 is the only produced water option requiring Cook Inlet platforms to meet zero-discharge requirements. Under a zero-discharge requirement, three platforms shut in during the first year and Cook Inlet lifetime production drops by 16.0 million discounted BOE

TABLE 5-4

IMPACTS OF PRODUCED WATER OPTIONS ON COOK INLET PLATFORMS ($1992)

Type of Impact	Option #1 and #3	Option #2 and #4	Option #5
Projected lifetime discounted production (BOE)	198,126,482	195,022,411	182,176,442
Change in discounted production (BOE)	---	3,104,070	15,950,040
Percentage change in discounted baseline production	---	1.6%	8.8%
Total projected lifetime production (BOE)	306,941,390	302,310,372	282,450,475
Change in total projected lifetime production (BOE)	---	4,631,018	24,490,916
Present value of projected producer net income (NPV)	$416,236	$407,507	$324,746
Change in NPV	---	$8,729	$91,490
Percentage change in NPV	---	2.1%	28.2%
Number of platforms ceasing production in first year	0	0	3
Total number of production years (1996 on)	156	150	124
Average production years per platform (all platforms)	11.1	10.7	8.9
Average production years per platform (nonclosing platforms)*	11.1	10.7	11.3
Total production years lost among closing platforms	---	0	26
Total production years lost among nonclosing platforms	---	6	6
Present value of severance taxes collected ($000)	$60,291	$60,131	$59,467
Change in present value of severance taxes ($000)	---	$159	$824
Percentage change in severance taxes	---	0.3%	1.4%
Present value of income taxes collected ($000)	$240,981	$235,729	$200,809
Change in present value of income taxes ($000)	---	$5,252	$40,171
Percentage change in income taxes	---	2.2%	20.0%
Present value of royalties collected ($000)	$264,114	$258,917	$235,350
Change in present value of royalties ($000)	---	$5,197	$28,764
Percentage change in royalties	---	2.0%	12.2%

Source: ERG estimates.

*Average production years go up from baseline and under Options #2 and #4 among nonclosing platforms under Option #5 because the three platforms that shut in under this option were staying open and pulling down the average in the baseline and Options #2 and #4

(22.5 million total BOE), or 8.8 percent of baseline production. Producers' projected net present value drops by $91.5 million, which is 28.2 percent of their baseline net present value ($13.6 million annually). The average productive life of the platforms drops to 8.9 years, although among platforms remaining active, this average is 11.3 years (this number is higher than the baseline years of operation because the three platforms that shut in under Option #5 pulled down the average in the baseline).

The total present value loss of federal income taxes is estimated to total $40.2 million over the lifetime of the Cook Inlet platforms under this option ($5.6 million annually over the 11-year life, on average), which is 20.0 percent of projected income tax receipts in the baseline. The present value of severance taxes lost are estimated to be $0.8 million over the lifetime of the Cook Inlet platforms ($0.1 million, on average, annually), or 1.4 percent of total baseline severance taxes estimated to be collected. Loss in royalty payments to the state (in present value terms) will total $28.8 million over the life of the platforms ($4.0 million, annually, on average), or 12.2 percent of baseline royalties collected. The present value of total lifetime lost revenues to the state are, thus, $29.6 million ($4.1 million, on average, annually) (see Table 5-4).

5.3.2.2 Drilling Fluids

Baseline Analysis Results (Option #1)

Option #1 results are identical to the baseline results under Option #1 for Produced Water in Cook Inlet (see Section 5.3.2.1 above and Table 5-5).

Option #2

Option #2 requires drilling wastes to meet a 100,000- to 1-million-ppm toxicity limit, in addition to offshore requirements. As discussed in EPA's Development Document (EPA, 1995), only 17 percent of the drilling waste is expected to fail to meet this limit; thus, only 17 percent of all drilling waste in Cook Inlet will require disposal other than discharge. Under this option,

TABLE 5-5

IMPACTS OF DRILLING WASTE OPTIONS
ON COOK INLET PLATFORMS ($1992)

Type of Impact	Option #1	Option #2	Option #3
Projected lifetime discounted production (BOE)	198,126,482	195,470,852	192,690,517
Change in discounted production (BOE)	---	2,655,630	5,435,964
Percentage change in discounted baseline production	---	1.4%	2.8%
Total projected lifetime production (BOE)	306,941,390	303,299,053	299,176,409
Change in total projected lifetime production (BOE)	---	3,642,338	7,764,982
Present value of projected producer net income (NPV)	$416,236	$415,973	$410,148
Change in NPV	---	$263	$6,089
Percentage change in NPV	---	0.1%	1.5%
Number of platforms ceasing production in first year	0	0	0
Total number of production years (1996 on)	156	153	143
Average production years per platform (all platforms)	11.1	10.9	10.2
Average production years per platform (nonclosing platforms)	11.1	10.9	10.2
Total production years lost among closing platforms	---	0	0
Total production years lost among nonclosing platforms	---	3	13
Present value of severance taxes collected ($000)	$60,291	$60,158	$60,019
Change in present value of severance taxes ($000)	---	$133	$272
Percentage change in severance taxes	---	0.2%	0.5%
Present value of income taxes collected ($000)	$240,981	$238,394	$233,056
Change in present value of income taxes ($000)	---	$2,586	$7,925
Percentage change in income taxes	---	1.1%	3.4%
Present value of royalties collected ($000)	$264,114	$259,840	$254,720
Change in present value of royalties ($000)	---	$4,274	$9,394
Percentage change in royalties	---	1.6%	3.7%

Source: ERG estimates.

there is a loss of lifetime production in Cook Inlet of 2.7 million discounted BOE (3.6 million total BOE), or 1.4 percent of total lifetime Cook Inlet production (stemming from three wells that will not be drilled under this scenario); no platforms shut in during the first year; and the present value of net producer income falls by $0.3 ($0.04 million annually) million, or less than 0.1 percent of baseline net present value.[9] Average platform lifetime decreases by only 0.2 years (2 months). The present value of state severance tax collections falls by $133,000 ($19,000 annually, on average over the 11-year life of platforms under this option, or 0.2 percent of baseline) and the present value of royalties decreases by $4.3 million ($0.6 million, on average, annually, or 1.6 percent of baseline). The present value federal tax collections falls by $2.6 million over the life of the platforms ($0.4 million, on average, annually), or 1.1 percent of projected baseline collections (see Table 5-5).

Option #3

Option #3 requires zero discharge of all drilling waste. Under this option, no platforms shut in during the first year, but six wells that are planned to be drilled will not be drilled. The total lifetime production lost is estimated to be 5.4 million discounted BOE (7.8 million total BOE), or 2.8 percent of lifetime baseline production. Producers' net present value of income lost totals $6.1 million ($0.9 million annually), which is 1.5 percent of total baseline net present value of income. The average number of production years per platform under this option is 10.2 years, vs. 11.1 years in the baseline scenario, a loss of about 1 year.

The present value loss of federal income tax over the lifetime of the platforms is projected to be $7.9 million ($1.2 million, on average, annually over the 10-year life of platforms under this option, or 3.4 percent of baseline federal income taxes), with the present value of

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[9]This loss is very small because of a baseline model assumption for one platform. Industry sources have indicated that three wells will be drilled on the platform. Model runs, however, indicated that the platform would be more profitable without the three wells. Since under post-compliance scenarios the three wells cannot be drilled without the platform operating at a loss, these wells are assumed not to be drilled. This assumption leads to an increase in net present relative to the baseline, although not so much of an increase as to offset all losses in net present value stemming from compliance costs.

severance tax losses totaling $0.3 million ($0.04 million, on average, annually, or 0.5 percent of baseline severance taxes). The present value of royalty losses to the state totals $9.4 million ($1.4 million, on average, annually), or 3.7 percent of the baseline royalties collected. Total present value losses to the state from royalties and severance taxes lost are, thus, $9.7 million ($1.44 million, on average, annually) (see Table 5-5).

5.3.3 Total Impacts—Gulf of Mexico Wells and Cook Inlet Platforms, Produced Water Options

As Table 5-6 shows, total produced water impacts across both regions tend to increase with option number. Options #2, #3, and #4 show moderate, incremental increases in impacts, whereas Option #5, in many instances shows a large incremental change in impacts from Option #4. In many cases, Option #5 impacts are two times greater than Option #2 impacts.

The selected option, Option #4, is associated with 111 wells and no platforms shutting in and losses in production totaling 15.2 million discounted BOE (which is at most 1.7 percent of total projected lifetime production in the Gulf of Mexico and Cook Inlet combined) or 32.4 million total BOE. The net present value lost by producers totals $153.2 million ($22.8 million annually), or at most 1.4 percent of their baseline projected net present value in the Gulf of Mexico and Cook Inlet combined. Note that these losses include the producers' share of compliance costs (posttax costs). The present value of income taxes lost are estimated at $84.9 million ($12.7 million on average annually) over a 10-year expected life, or 10.1 percent of taxes collected from discharging coastal wells and platforms in the Gulf of Mexico and Cook Inlet. The present value of severance tax losses under Option #4 totals $10.7 million ($1.6 million on average annually), or 3.8 percent of projected baseline collections in the Gulf of Mexico and Cook Inlet among discharging coastal wells and platforms. Finally, royalties lost to the states total $34.3 million ($5.1 million on average annually), or 5.1 percent of projected baseline royalties to the states in the Gulf of Mexico and Cook Inlet among discharging coastal wells and platforms.

TABLE 5-6

TOTAL ECONOMIC IMPACTS (INCLUDING PRODUCTION LOSSES): GULF OF MEXICO AND COOK INLET REGIONS COMBINED (Produced Water Only)

	Option #1	Option #2	Option #3	Option #4	Option #5
Number of wells and platforms shut in	0 wells 0 platforms	42 wells 0 platforms	111 wells 0 platforms	111 wells 0 platforms	111 wells 3 platforms
Lifetime production lost (million discounted BOE)	0	12.5	12.1	15.2	28.0
Total lifetime production lost (million BOE)	0	27.6	27.8	32.4	50.2
Present value of producers' net income lost ($000)	0	$114,651	$144,48	$153,209	$235,970
Present value of federal/state income taxes lost ($000)	0	$61,320	$79,651	$84,903	$119,822
Present value of lost severance taxes ($000)	0	$5,592	$10,517	$10,676	$11,341
Present value of lost royalties ($000)	0	$21,007	$29,058	$34,255	$57,822
Total losses (includes compliance costs) ($000)	0	$202,570	$263,706	$283,043	$424,955

Source: ERG estimates.

Total social losses can be calculated by adding losses to producers to losses to state and federal governments and others through losses in income taxes, severance taxes, and royalties. Because compliance costs reduce producer net income and income taxes, the total includes compliance costs as well as the value of additional production losses stemming from earlier well and platform shut ins. As Table 5-6 shows, the total present value impacts of Option #4 are estimated to be $283.0 million ($42.2 million annually).

5.3.4 Impacts From the Co-proposed Regulatory Options for TWC

Costs of disposing of TWC under a zero-discharge option are $605,645 annually for all Gulf of Mexico wells estimated to discharge TWC (a minimum of 334 wells in 1992), or an average of $1,813 per well. A typical Gulf of Mexico well produces an average of 36 barrels of oil per day according to the 1992 Coastal Oil and Gas Questionnaire. At $18 per barrel, total production revenue at a typical well is estimated to be $237,000 per year. Thus, if the zero discharge option is ultimately selected, TWC disposal costs are estimated to be 0.8 percent of annual production revenues at a typical Gulf of Mexico well, and no major impacts are expected as a result of either co-proposed option.

5.3.5 Total Impacts, Selected Options

As Table 5-7 shows, total maximum impacts from the selected regulatory options (the actual total will depend on the final choice of the drilling waste option) are estimated to be as follows: 111 wells are expected to shut in; up to 17.9 million discounted BOE (40.2 million total BOE) are estimated to be lost (1.1 to 2.0 percent of projected baseline production in the Gulf of Mexico and Cook Inlet coastal regions); and up to $160.4 million in net present value ($23.9 million annually) is expected to be lost (0.7 to 1.5 percent of the NPV of production in the Gulf of Mexico and Cook Inlet coastal regions).

The maximum present value of federal and state income taxes lost totals $91.0 million ($13.6 million on average annually—primarily federal), which is 10.8 percent of projected lifetime

TABLE 5-7

TOTAL ECONOMIC IMPACTS TO GULF OF MEXICO AND COOK INLET REGIONS FROM THE SELECTED OPTIONS[a]

	Option #4 Produced Water	Option #2 Drilling Waste	Option #3 Drilling Waste	Total Impacts With Option #2 Drilling Waste	Total Impacts With Option #3 Drilling Waste[b]
Number of wells and platforms shut in	111 wells 0 platforms	0 wells 0 platforms	0 wells 0 platforms	111 wells 0 platforms	111 wells 0 platforms
Discounted production lost (million BOE)	15.2	2.7	5.4	15.2	17.9
Total production lost (million BOE)	32.4	3.6	7.8	32.4	40.2
Net present value (NPV) of production lost ($000)	$153,209	$263	$6,089	$154,584	$160,409
Present value of federal taxes lost ($000)	$84,903	$2,586	$7,925	$85,611	$90,950
Present value of lost severance taxes ($000)	$10,676	$133	$272	$10,676	$10,815
Present value of lost royalties ($000)	$34,255	$4,274	$9,394	$34,255	$39,375
Total present value of losses	$283,043	$7,256	$23,680	$285,126	$301,549

[a]Economic impacts from selected options for other regulated waste streams are expected to be negligible on these results.

[b]Economic impacts are not additive. Some double counting or undercounting of impacts occurs in the Cook Inlet analysis if produced water impacts are directly added to drilling waste impacts. The total reflects the removal of double counting and inclusion of synergistic impacts (see Table 5-8).

Source: ERG estimates.

income taxes in the baseline collected among discharging wells and platforms. The maximum present value of state severance taxes lost totals $10.8 million ($1.6 million on average annually), or 3.8 percent of projected lifetime severance taxes in the baseline collected among discharging wells and platforms. Finally, the maximum present value of royalties lost total $39.4 million ($5.9 million on average annually), or 5.8 percent of projected lifetime royalties in the baseline collected among discharging wells and platforms. Note that impacts on taxes and royalties are substantially less if taxes and royalties collected from nondischarging wells also are considered. Total economic impacts (including compliance costs) are as much as $301.5 million present value ($44.9 million annually).

Impacts from Options #4, produced water, and drilling waste Options #2 and #3 are not additive for Cook Inlet platforms (note that impacts for Option #4, produced water, and Option #1, drilling waste, are the same as Option #4, produced water, impacts alone). A small double counting and under counting of impacts occurs. Table 5-8 presents the results of the action of combining produced water and Option #3, drilling waste, on Cook Inlet platforms. As the table shows, impacts in some cases are slightly more or less than the sum of those presented in Tables 5-4 and 5-5.

5.4 REFERENCES

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TABLE 5-8

IMPACTS OF OPTION #4 PRODUCED WATER AND OPTION #3 DRILLING WASTE ON COOK INLET PLATFORMS ($1992)

Type of Impact	Baseline	Combined Options
Projected lifetime discounted production (BOE)	198,126,482	192,242,077
Change in discounted production (BOE)	---	5,884,405
Percentage change in discounted baseline production	---	3.1%
Total projected lifetime production (BOE)	306,941,390	298,187,728
Change in total projected lifetime production (BOE)	---	8,753,662
Present value of projected producer net income (NPV)	$416,236	$400,307
Change in NPV	---	$15,929
Percentage change in NPV	---	4.0%
Number of platforms ceasing production in first year	0	0
Total number of production years (1996 on)	156	140
Average production years per platform (all platforms)	11.1	10.0
Average production years per platform (nonclosing platforms)	11.1	10.0
Total production years lost among closing platforms	---	16
Total production years lost among nonclosing platforms	---	6
Present value of severance taxes collected ($000)	$60,291	$59,992
Change in present value of severance taxes ($000)	---	$298
Percentage change in severance taxes	---	0.5%
Present value of income taxes collected ($000)	$240,981	$229,682
Change in present value of income taxes ($000)	---	$11,299
Percentage change in income taxes	---	4.9%
Present value of royalties collected ($000)	$264,114	$253,797
Change in present value of royalties ($000)	---	$10,317
Percentage change in royalties	---	4.1%

Source: ERG estimates.

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SECTION SIX

ECONOMIC IMPACTS ON COASTAL OIL AND GAS FIRMS

The firm-level analysis evaluates the effects of regulatory compliance on firms owning one or more affected coastal oil and gas operations. It also serves to identify impacts not captured in the production loss analysis. For example, some companies might be too weak financially to undertake the investment in the required effluent control, even though the investment might seem financially feasible at the well level. The Section 308 survey asked respondents for financial data at the lowest level of organization where assets, liabilities, and taxes were clearly identifiable. Thus, the financial data should reflect the most financially sensitive level of organization (e.g., a division of a major company rather than corporate holdings, if the division acts as a profit center).

This analysis was conducted in three stages: In the first stage, a baseline analysis was undertaken. In the second stage a screening analysis was performed. In the third stage, operators who were identified as likely to remain in operation but who were deemed likely to incur substantial impact were examined in depth to determine whether these potential impacts were likely to materialize.

Note that the impacts discussed in this section do not take into account the requirements of EPA Region 6 General Permits for the Coastal Oil and Gas Industry covering disposal of produced water.

6.1 ANALYTICAL METHODOLOGY

6.1.1 Baseline Methodology

Ordinarily a cash-flow or similar analysis is undertaken to determine whether firms are likely to be considered a baseline failure; that is, whether their financial health is so precarious that they are highly likely to fail regardless of the regulation under consideration. This approach was not taken here because about 100 out of 233 operators reporting net income in the Section 308 survey reported negative net income. Such a large baseline failure rate would tend to reduce greatly any estimate of postcompliance failures. Because only one year's data are available (more years of data would tend to reduce the number of firms with negative net income) and because consistency with the later screening analysis needed to be maintained, an alternative baseline firm failure analysis was performed. As outlined under Section 6.2, for Gulf of Mexico firms, surveyed firms were linked with known permit holders in databases provided by the Texas Railroad Commission (RRC) and the Louisiana Department of Environmental Quality (DEQ). The firms that could be matched were investigated to determine the status of their equity and working capital. Where both equity and working capital were negative, the firm was considered extremely weak financially and likely to fail in the baseline. As noted in Section Three, working capital and equity were expected to be especially important means of financing pollution control costs in the Gulf region.

6.1.2 Screening Methodology

The screening analysis was performed to identify firms where impacts from compliance with the regulation are likely to be significant. As noted above, discharge permit holders were matched by name to Section 308 survey respondents who provided financial data. The annualized capital and operating and maintenance (O&M) costs for meeting effluent guideline requirements, which were presented in Section Four, were compared in the screening analysis to the equity and working capital of affected firms for which financial data are available, and a percentage change in equity and working capital was computed.

Equity and working capital are common measures of a firm's ability to afford new projects, acquisitions, etc. Equity is measured as a firm's total assets minus its total liabilities (i.e, its net worth). Working capital is a measure of a firm's liquidity and is measured as current assets (typically cash or near-cash assets that can easily be liquidated) minus current liabilities, which are debts or other obligations due within one year. Thus, working capital describes available cash. If the annual cost of complying with a zero-discharge requirement contributes to a very small percentage change in equity and working capital, it is likely that impacts at a firm will not be substantial (i.e., the firm is not likely to fail as a result of compliance). Firms where equity or working capital would change by more than 5 percent were identified as needing further analysis with one exception. S corporations, which have different tax incentives than publicly held corporations, often tend to minimize the appearance of working capital on their tax returns (the basis for most financial data from S corporations). Thus, large percentage changes in working capital combined with low percentage changes in equity are not considered a reason for alarm among S corporations, as long as the change in equity is less than 1 percent.

The screening analysis approach was used because effects on net income from complying with the regulations were difficult to determine in many instances. This difficulty arises because many firms had no discharging wells surveyed due to the survey sampling design. Unless at least one discharging well for each permitted facility operated by the firm was surveyed, the proportion of production associated with discharging vs. nondischarging wells could not be determined. Thus, whether the firm would sell or shut in production rather than install compliance equipment also could not be determined. Simply assuming that all firms would install compliance equipment could greatly overstate firm failures because in a number of cases it would be more economical to shut in production rather than install compliance equipment (for example, in the case of a marginal well with low hydrocarbon production but large volumes of produced water). Performing a detailed analyses on a small number of firms then allowed for case-by-case assessment that, in some instances, could circumvent some of the data limitations, given the complete analytical flexibility not allowed by computer models.

6.1.3 Detailed Analysis

Following the screening analysis, the detailed analysis looks at firms with change in equity or working capital of more than 5 percent to better gauge whether they can be considered to be substantially affected. Merely because the above analysis shows a 5 percent or greater change in working capital or equity does not necessarily mean the firm will experience substantial impacts. There are a number of reasons why firms showing substantial change in equity and working capital might not be as highly affected by the regulation as these measures might indicate:

- The firms might be considered baseline failures; that is, they would be likely to close without the regulation in place because of their existing poor financial condition. They are eliminated from any additional analysis and are not considered affected firms.

- The wells tied into the permitted facility might currently be generating insufficient revenue to cover operating expenditures. The wells associated with the permitted facility would, in this case, be considered baseline production loss; that is, they would be shut in regardless of the regulation. These types of impacts also are not considered impacts from the zero-discharge requirements of the effluent guidelines.

- The regulatory requirements might be achieved more economically under the regulation by shutting in production. This scenario is likely to result in minimal impacts when the revenue associated with the facility is a small portion of the firm's revenues (e.g., the wells are marginal producers, providing minimal oil or gas but large quantities of produced water). In this case, the firm incurs the cost of plugging and abandoning the wells and loses a small portion of revenue—an impact attributable to the effluent guidelines, but potentially a much smaller impact than continuing to produce.

- The firm might be in a partnership with other firms or individuals and, thus, incurs only a fraction of the cost to meet zero discharge.

- The firm might be an operator only. Costs would be passed through to the owner companies or individuals.

- If only working capital is substantially affected, and the company is an S corporation, impact might be overstated. It is to an S corporation's advantage to minimize working capital amounts on balance sheets when filing taxes; so balance sheet statements submitted in support of tax filings for S corporations are assumed to be at or near yearly minimums.

- The firm might have an unusually low equity or working capital situation in relationship to returns. When returns are analyzed in more depth, they may show the ability of the company to absorb compliance costs without appreciably affecting financial health.

A variety of measures are used in the detailed analysis to assess impacts, although a key part of the analysis investigates return on assets (ROA) and return on equity (ROE). These ratios use net income divided by total firm assets or equity as a measure of return on investment in the firm. Where return appears minimally affected and still ranges from adequate to relatively good compared to industry averages, no substantial impact is estimated since a promise of good returns can usually attract investment capital.

ROE and/or ROA are common measures of the profitability of the firm and the ability of the firm to attract capital. A firm with an adequate return for the industry, measured as ROA or ROE above the lowest quartile for these ratios among the industry, typically would not be considered to be in financial jeopardy. According to Dun & Bradstreet, in 1992 average ROA in the industry was 3.5 percent; the lowest quartile was -1.3 percent. For ROE, the average was 6.2 percent; the lowest quartile was -2.0 percent.

Note that because most financial data from the Section 308 survey are confidential, the impacts for individual companies cannot be listed by name. Summary statistics are presented; the aggregated nature of the statistics helps maintain confidentiality. Also, a list is presented showing the change in equity and working capital for each firm in the analysis, but without the name or the data used to calculate the financial ratios.

6.2 SOURCES OF DATA

Sources of data for Cook Inlet operators were provided in the Section 308 survey or annual reports. Sources of data for the Gulf were not as readily available, since the Section 308 survey did not capture all Gulf coastal operators, thus, operators were identified using state data.

EPA received two databases providing information on permit numbers, permit holders, discharge volumes, field names, and other data from the states of Louisiana and Texas. For the purpose of this report, the data are considered current as of 1993. Based on compliance dates in the database, communications with Louisiana DEQ, information on court ordered deadlines for certain operators to cease discharging, and Section 308 survey responses (see U.S. EPA, 1994), treatment facilities and operators that will cease discharging by 1996 were identified and dropped from the analysis. The number of permit holders in Louisiana in the 1993 permit database totals 73 operators; for 1996 the number of operators still holding discharge permits is estimated to be 43 operators. The number of permit holders in Texas in 1993 totals 89 operators; for 1996 this is estimated to be 83 operators. The numbers for both states include 8 operators that hold permits in both states, which is estimated to drop to 4 in 1996. The current data include Chapman facilities as well.[1] The total number of operators holding discharge permits in either state is 154, which will drop to 122 in 1996 (not including double count of operators holding permits in both states).

Also used with the permit data are survey data from the Section 308 survey. The way in which operators were identified for inclusion in the survey, data limitations, and the method used for determining the universe of coastal operators (which total 270 operators) is discussed in Sections Two and Three of this EIA. Financial data from 233 of these 270 operators were sufficiently detailed to use in this analysis.

A total of 96 of the 154 operators (62 percent) estimated to be holding permits were surveyed in the Section 308 survey. Data are available for 81 of the 154 operators (53 percent), including the 7 of 8 operators with permits in both states; however, adjustments were made to these data to eliminate dischargers expected to cease discharging by 1996. When these adjustments are made, a total of 70 out of 122 operators (57 percent) were matched, including 4 operators with permits in both states. Data are available for 58[2] operators out of 122 operators

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[1]Facilities serving wells located on land, but south and east of the Chapman Line in Louisiana and Texas (see Section Three).

[2]Two operators did not provide financial data, so data from Avanti's report (1992) on Region 6 permits were used for these two operators.

(48 percent) known to have permits. For Louisiana, information is available to analyze 27 of 43 operators (63 percent). For Texas, information is available to analyze 34 of 83 operators (41 percent). All but one operator holding permits in both states had financial data available.

For several reasons, not all permit holders are included in the Section 308 survey. As noted in Section Three, EPA believes that the survey has not captured the universe of discharging facilities, primarily because wells completed prior to 1980 were not included in the survey. A total of 123 out of 325 discharging facilities are estimated to have been missed by the survey for this reason. Thus, the maximum number of operators surveyed is estimated assuming operators other than those captured in the survey are operating the missing facilities. Furthermore, it is assumed that nondischarging facilities were missed in the same proportion as discharging facilities and are likewise operated by nonsurvey operators. The maximum estimate of total operators is computed using the same ratio of surveyed facilities to total known facilities used to estimate total coastal wells (a factor of 1.61). When extrapolating on this basis, 435 coastal operators are estimated based on the 270 in the Section 308 survey.

Some operators are missing from the analysis because financial information is unavailable in the database:

- If the survey has not yet been returned, no entry has been made in the database for that operator. Five firms in this analysis have not yet returned their surveys.
- "Out-of-scope" operators are not included in the database. Many of the operators surveyed in the Section 308 survey responded as being out of scope (i.e., they did not own, operate, or drill coastal wells or were out of business in 1992). No information was required by the survey if they were out of scope. Six of these out-of-scope operators, however, were also listed as state permit holders.
- A few firms were identified as operators only (i.e., they do not own the well they operate; one firm in this analysis is considered an operator only and no financial information was obtained for them).

Because only 58 surveyed operators with sufficient financial data could be linked to the 122 operators identified in the permit databases, estimates of impact assume that only half of the relevant operators were captured in this analysis. It is further assumed that this sample of

operators is unbiased, and, thus, estimates of impact are extrapolated to the entire coastal universe of operators by multiplying results by two.

6.3 USE OF DATA IN THE ANALYSIS

The data discussed above are used to identify impacts on firms. Concern was expressed that costs might be incurred by more than the permit operator; that is, if coastal well operators used other, permitted operators' facilities, some of the costs would not be borne by the permitted operator, but would be passed through to other coastal well operators who do not own discharge facilities. ERG investigated this possibility using the Section 308 survey and found that the majority of discharging operators are either sole or joint owners and operators of their facility. Thus, compliance costs passed through to other well operators who do not own a stake in the wells served by the facility will not be a significant factor in the economic analysis.

Two types of operations were of concern: commercial operations and well operators who indicated that they did not own the discharging facility. Based on unweighted data in the Section 308 survey, among operators discharging from currently permitted facilities, one operator indicates that it neither owns the facility nor the wells that it operates.[3] Two operators, which do not report a valid permit number in the survey, do not own but are the sole operators of their facilities. It is not known if these facilities are still permitted or who is listed as the permit holder. Only one operator reports using a noncommercial discharging facility operated—and presumably owned—by another operator identified in the permit database. No operators are identified in the survey that use currently permitted commercial discharging facilities (note: these results are based on the 146 surveys in the first interim survey database). All other operators with wells that discharge produced water indicate that they are the sole owner and

[3]Several firms appear to own only a very small share of the wells they operate; they are nearly exclusively operators. Many of these show up in the detailed analysis because of the discrepancy between the financial size of the operator versus the size of the facilities operated (volumes of produced water). As noted later, these operators are considered possible firm failures because of lack of information.

operator or joint owner and operator of their discharge facility.[4] Thus, for the purpose of this analysis, costs for meeting no-discharge requirements for the permitted facility are assumed to fall solely on the operator who holds that facility's permit. This assumption should not substantially affect the analysis; however, the resulting analysis would tend to be conservative if the assumption has any effect, because the impact of cost increases is not assumed to be shared by two or more firms.

6.4 RESULTS OF FIRM-LEVEL ANALYSIS

As discussed in Section 6.1, the results of three levels of analysis are presented here. The results of the baseline analysis are presented in Section 6.4.1, the results of screening analysis are presented in Section 6.4.2, and the results of the detailed analysis are presented in Section 6.4.3.

In the baseline analysis, firms with negative equity and working capital are considered baseline failures and removed from further postcompliance analysis. In the screening analysis, the annual costs of meeting either a gas flotation or zero-discharge requirement are subtracted from each firm's equity and working capital and the percentage decrease in equity and working capital is then calculated. These declines are compared to a benchmark of 5 percent (i.e., a count is presented of the number of firms having their equity or working capital reduced by more than 5 percent as a result of a regulatory option).

In the detailed analysis, all firms with a 5 percent or greater change in either equity or working capital are investigating using all available survey information and additional financial indicators to refine the initial estimates of potentially substantial impact on coastal oil and gas firms.

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[4]Oil and gas operations are often jointly owned, with numerous working interest shares in a project possible. It is very difficult to trace impacts to individuals or other firms with working interests. This procedure would be similar to trying to trace impacts back to individual shareholders in a firm in other industries. As long as the operator is also the owner, the first level of impacts can be assumed to be felt by the operator. Once increased costs are absorbed by the project, the other partners would most likely then be provided reduced revenue shares.

Following the determination of impacts for the Gulf of Mexico (improved gas flotation vs. zero discharge for produced water) and for Cook Inlet (improved gas flotation vs. zero discharge for produced water; 1-million-ppm toxicity standard vs. zero discharge for drilling waste), Section 6.4.3 presents the impacts organized by waste stream and regulatory option.

6.4.1 Baseline Analysis

Five of the 58 matched firms (9 percent) currently have both negative equity and negative working capital. These firms are considered very likely to fail regardless of whether any regulatory actions are taken. Thus, 53 firms are analyzed in the screening analysis. Note that all five firms are considered small based on Small Business Administration (SBA) Guidelines ($\leq$500 employees; see Section Nine for more information).

6.4.1.1 Gulf of Mexico

All Gulf of Mexico coastal oil and gas firms matched in the analysis database were investigated to determine changes in equity and working capital resulting from outlays for incremental disposal costs (produced water costs) by size of firm.[5] Table 6-1 presents the results of this analysis for the 13 large and 45 small operators.

Out of 40 firms, 3 small firms reported nonpositive equity, whereas none of the large firms reported negative equity. Of the remaining firms, 23 small firms (56 percent of small firms) and all large firms are expected to experience a change in equity of less than 5 percent if improved gas flotation is used to meet limits on oil and grease, with 14 small firms (35 percent of small firms) and no large firms expected to experience a change in equity of more than 5 percent. The change in equity among small firms ranges from 0.0121 to 4,909 percent with a

[5]Size of operator was determined based on SBA's guidance on what constitutes a small firm in the oil and gas production industry ($\leq$500 employees is defined as small) and responses to employment questions in Section 3 of the survey. The one firm for which employee size is not known was assumed to fall into the small category.

TABLE 6-1

CHANGES IN EQUITY AND WORKING CAPITAL ASSOCIATED WITH THE IMPROVED GAS FLOTATION OPTION (GULF OF MEXICO)

Level of Change	Small Operators	Large Operators	Total
Change in Equity			
NA	3	0	3
<1%	18	13	31
1% to 5%	5	0	5
>5%	14	0	14
Total	40	13	53
Change in Working Capital			
NA	11	8	19
<1%	8	5	13
1% to 5%	8	0	8
>5%	13	0	13
Total	40	13	53

NA = Nonpositive equity or working capital.

median of 1.26 percent. The change in equity among large firms ranges from 0.0001 to 0.10 percent with a median of 0.01 percent (Table 6-2).

If zero discharge were required, no additional small firms are expected to experience a change in equity of greater than 5 percent (Table 6-3). The median change in equity among small firms remains the same, whereas the median change in equity among large firms rises to 0.02 percent (Table 6-4).

Eleven small firms and 8 large firms report nonpositive working capital (see Table 6-1). Sixteen small firms (40 percent of small firms) and all large firms are expected to experience changes in working capital of less than 5 percent if improved gas flotation were used to meet a limit on oil and grease, while 13 small firms (32 percent of small firms) and no large firms are expected to experience changes in working capital of more than 1 percent (see Table 6-3). The change in working capital among small firms ranges from 0.0401 to 382 percent, with a median of 2.80 percent. The change in working capital among large firms ranges from 0.0016 to 0.31 percent with a median of 0.04 percent (see Table 6-2).

If zero discharge were required, no additional small firms are expected to experience a change in working capital of greater than 5 percent (see Table 6-3). The median change in working capital among small firms rises to 4.54 percent, while the median change in working capital among large firms rises to 0.05 percent (see Table 6-4).

Tables 6-5 through 6-8 present a firm-by-firm listing of changes in equity and working capital for both large firms (Table 6-5 and 6-6) and small firms (Table 6-7 and 6-8) under the improved gas flotation and zero-discharge option.

As Tables 6-5 and 6-6 show, no large firms are expected to experience substantial impacts as a result of either a more stringent oil and grease limit or a zero-discharge requirement. Tables 6-7 and 6-8, however, indicate that a number of small firms need to be investigated more fully to determine whether impacts are likely to be substantial (shown as shaded entries). Note that the same firms needing further investigation under the improved gas flotation option also require further investigation under the zero-discharge option.

TABLE 6-2

RANGE AND MEDIAN CHANGE IN EQUITY AND WORKING CAPITAL ASSOCIATED WITH THE IMPROVED GAS FLOTATION OPTION (GULF OF MEXICO)

Operator Size	Minimum Change	Maximum Change	Median Change
Change in Equity			
Large operators	0.0001%	0.10%	0.01%
Small operators	0.0121%	4,909%	1.26%
All	0.0001%	4,909%	0.27%
Change in Working Capital			
Large operators	0.0016%	0.31%	0.04%
Small operators	0.0401%	382%	2.80%
All	0.0016%	382%	1.44%

TABLE 6-3

CHANGES IN EQUITY AND WORKING CAPITAL ASSOCIATED WITH THE ZERO-DISCHARGE OPTION (GULF OF MEXICO)

Level of Change	Small Operators	Large Operators	Total
Change in Equity			
NA	3	0	3
<1%	18	13	31
1% to 5%	5	0	5
>5%	14	0	14
Total	40	13	53
Change in Working Capital			
NA	11	8	19
<1%	7	5	12
1% to 5%	9	0	9
>5%	13	0	13
Total	40	13	53

NA = Nonpositive equity or working capital.

TABLE 6-4

RANGE AND MEDIAN CHANGE IN EQUITY AND WORKING CAPITAL ASSOCIATED WITH ZERO-DISCHARGE OPTION (GULF OF MEXICO)

Operator Size	Minimum Change	Maximum Change	Median Change
Change in Equity			
Large operators	0.0001%	0.20%	0.02%
Small operators	0.0121%	9,830%	1.26%
All	0.0001%	9,830%	0.37%
Change in Working Capital			
Large operators	0.0016%	0.55%	0.05%
Small operators	0.0383%	2,442%	4.54%
All	0.0016%	2,442%	2.63%

TABLE 6-5

IMPROVED GAS FLOTATION OPTION: EQUITY AND WORKING CAPITAL CHANGES FOR LARGE OPERATORS (GULF OF MEXICO)

Firm Number	Improved Gas Flotation Equity Change	Improved Gas Flotation Working Capital Change
1	0.10%	NA
2	0.06%	0.31%
3	0.02%	NA
4	0.02%	NA
5	0.02%	0.04%
6	0.01%	NA
7	0.01%	NA
8	0.01%	0.26%
9	0.01%	NA
10	0.01%	NA
11	0.00%	NA
12	0.00%	0.02%
13	0.00%	0.00%

NA = Nonpositive equity or working capital.

TABLE 6-6

ZERO DISCHARGE: EQUITY AND WORKING CAPITAL CHANGES FOR LARGE OPERATORS (GULF OF MEXICO)

Firm Number	Zero-Discharge Equity Change	Zero-Discharge Working Capital Change
1	0.20%	NA
2	0.10%	0.50%
3	0.03%	NA
4	0.03%	NA
5	0.02%	0.05%
6	0.02%	NA
7	0.02%	NA
8	0.02%	NA
9	0.02%	0.55%
10	0.01%	NA
11	0.01%	NA
12	0.00%	0.02%
13	0.00%	0.00%

NA = Nonpositive equity or working capital.

TABLE 6-7

IMPROVED GAS FLOTATION: EQUITY AND WORKING CAPITAL CHANGES FOR SMALL OPERATORS (GULF OF MEXICO)

Firm Number	Improved Gas Flotation Equity Change	Improved Gas Flotation Working Capital Change
1	4908.79%	NA
2	807.98%	NA
3	525.71%	288.29%
4	407.73%	174.74%
5	322.98%	NA
6	236.18%	236.18%
7	93.98%	NA
8	43.16%	53.13%
9	31.30%	186.60%
10	29.71%	31.12%
11	16.65%	147.83%
12	11.35%	381.52%
13	10.54%	4.85%
14	5.00%	80.30%
15	4.01%	NA
16	1.60%	NA
17	1.44%	NA
18	1.29%	1.39%
19	1.26%	NA
20	0.63%	1.28%
21	0.63%	0.63%
22	0.37%	1.49%
23	0.37%	NA
24	0.36%	11.52%
25	0.31%	1.95%
26	0.23%	1.32%
27	0.21%	0.27%
28	0.16%	5.06%
29	0.14%	2.80%
30	0.13%	0.65%
31	0.08%	0.23%
32	0.07%	0.81%

TABLE 6-7 (continued)

Firm Number	Improved Gas Flotation Equity Change	Improved Gas Flotation Working Capital Change
33	0.07%	NA
34	0.05%	1.01%
35	0.04%	0.04%
36	0.03%	NA
37	0.01%	0.16%
38	NA	NA
39	NA	34.78%
40	NA	NA
41	NA	NA
42	NA	0.34%
43	NA	11.35%
44	NA	NA
45	NA	NA

NA = Nonpositive equity or working capital.

TABLE 6-8

ZERO DISCHARGE: EQUITY AND WORKING CAPITAL CHANGES FOR SMALL OPERATORS (GULF OF MEXICO)

Firm Number	Zero-Discharge Equity Change	Zero-Discharge Working Capital Change
1	9829.79%	NA
2	811.22%	NA
3	1060.70%	581.67%
4	688.63%	295.13%
5	337.34%	NA
6	262.03%	262.03%
7	100.56%	NA
8	47.83%	58.87%
9	30.73%	183.21%
10	44.03%	46.12%
11	20.23%	179.57%
12	72.67%	2442.48%
13	9.88%	4.54%
14	5.00%	80.30%
15	4.57%	NA
16	3.18%	NA
17	4.19%	NA
18	2.14%	2.31%
19	1.26%	NA
20	0.63%	1.28%
21	0.98%	0.97%
22	0.85%	3.37%
23	0.58%	NA
24	0.58%	18.58%
25	0.47%	2.95%
26	0.23%	1.32%
27	0.23%	0.29%
28	0.27%	8.59%
29	0.24%	4.75%
30	0.13%	0.65%
31	0.14%	0.40%
32	0.12%	1.31%

TABLE 6-8 (continued)

Firm Number	Zero-Discharge Equity Change	Zero-Discharge Working Capital Change
33	0.07%	NA
34	0.05%	NA
35	0.03%	0.04%
36	0.05%	1.01%
37	0.01%	0.16%
38	NA	48.89%
39	NA	0.34%
40	NA	19.51%

NA = Nonpositive equity or working capital.

6.4.1.2 Cook Inlet

None of the five operators in Cook Inlet are expected to experience a change in equity or working capital of greater than 5 percent under either the improved gas flotation option or the zero-discharge option for produced water or under the 1-million-ppm toxicity limit or zero discharge limit for drilling waste. Because so few firms are located in Cook Inlet, detailed information is not provided in the public record to protect confidential business information. No further analysis of these firms was undertaken.

6.4.2 Detailed Analysis

A number of firms (as defined by number in Tables 6-7 and 6-8) were selected for more in-depth analysis of survey responses in an attempt to identify conditions such as those listed above that would indicate substantially less impact than that suggested by the use of change in equity and working capital. Note that no substantial differences in potential impacts are indicated between the improved gas flotation option and zero discharge. None of the large firms (in Tables 6-4 and 6-5) are considered for further analysis. Of the remaining 40 small firms not identified as baseline failures, 16 firms were initially identified for further analysis. These include numbers 1 through 14 in Table 6-6, as well as numbers 38 and 40. Several other firms were checked to see if they are S corporations. These firms had greater than 5 percent change in working capital associated with both gas flotation and zero discharge, but less than 1 percent change in equity. As noted above, a large change in working capital with a minor change in equity might not constitute substantial impact in S corporations. Firm numbers 24 and 28 were investigated for their status as S corporations; neither are S corporations. Firms 24 and 28 were therefore included in the in-depth analysis, for a total of 18 firms.

Table 6-9 presents the results of the in-depth analysis performed on these 18 firms. For reasons explained in the comment column in the table, of these 18 firms, 4 are considered additional baseline failures and 2 are expected to have already plugged and abandoned the wells that are served by its discharging facility before the time that the effluent guidelines take effect. Of the remaining 12 firms, 3 firms are expected to plug and abandon wells or sell their wells (if

TABLE 6-9

RESULTS OF FURTHER FINANCIAL ANALYSIS OF SELECTED COASTAL REGION OIL AND GAS PRODUCTION OPERATORS (GULF OF MEXICO)

Firm No.	Likely Baseline Firm Failure	Likely Baseline P&A*	Likely to P&A or Sell Properties in Response to Permit but Not Firm Failure	Some Impact but Not Firm Failure	Possible Firm Failure but Need More Information	Firm Failure	Comments
1					X		Not enough information; clearly getting only a tiny fraction of income from properties. May be primarily an operator only.
2	X						Firm has negative net income; unable to borrow money as per survey comment; negative current assets. Likely baseline fail.
3					X		Seems to be getting little or no production revenue; may be primarily or exclusively an operator. Also, water volumes for one permit seem somewhat unlikely given number of coastal wells claimed by respondent, on the order of a minimum 160 kbbls per year per well.
4					X		Appears to be primarily or exclusively operator only.
5			X				Impacts from P&A and lost revenues, but return on assets and return on equity still likely to be very good relative to industry averages post-compliance.
6					X		Operator only; owns no coastal wells
7					X		Did not provide enough info. in survey to make judgment.
8		X					Current loss in coastal portion of business; wells likely to be P&A; other business appears healthy.

TABLE 6-9 (continued)

Firm No.	Likely Baseline Firm Failure	Likely Baseline P&A*	Likely to P&A or Sell Properties in Response to Permit but Not Firm Failure	Some Impact but Not Firm Failure	Possible Firm Failure but Need More Information	Firm Failure	Comments
9				X			Analysis shows large change in working capital, but working capital unusually low probably because used to pay for workover. If cost of workover ignored, impact on working capital still high (over 30%) but change in equity very low and return on assets and return on equity still likely to be good compared to industry average. Is an S corp., so change in working capital less of an issue.
10				X			Cost difference between cost per barrel of discharge and highest postcompliance cost estimate is $0.12. Based on reported volumes in survey, this would lead to an additional cost per year of $2,500. Return is still good compared to industry average. Acceptable return even if compliance costs are over 1.5 times higher.
11			X				Impacts from P&A and lost revenues, but return on assets and return on equity still likely to be very good relative to industry averages post-compliance.
12					X		Very complex financial picture; only takes about a 10% share of net revenues from wells operated.
13			X				Revenues from coastal operations are miniscule: 0.07% of total revenues; elimination of coastal revenues has virtually no impact on returns.
14	X						Large net income losses.

TABLE 6-9 (continued)

Firm No.	Likely Baseline Firm Failure	Likely Baseline P&A*	Likely to P&A or Sell Properties in Response to Permit but Not Firm Failure	Some Impact but Not Firm Failure	Possible Firm Failure but Need More Information	Firm Failure	Comments
24		X					Operates only marginal wells in the coastal region. In 1992 coastal operating costs were more than double coastal revenues. It is likely that very few if any of their coastal wells are profitable to operate. Coastal operations are only a very small fraction of their total business.
28	X						Negative earnings, negative net income. Coastal operations very tiny fraction of total business. Even if not a baseline fail, loss of coastal revenue would not contribute much to total loss (less than 1%).
38	X						Highly leveraged firm; interest payments 5 times earnings before interest and taxes (EBIT)—extremely poor relative to industry. Relatively large net loss for year.
40				X			Return on assets still very strong after compliance costs are incurred.

Note: Shaded columns indicate possible firm failure (used in the estimate of firms that might experience substantial impact)
*P&A = Plug and abandon.

still economically viable) in response to the regulation; this is not considered a substantial firm impact (i.e., firm failure), however, since coastal operations are a very small percentage of their total revenues and returns are expected to continue to be good, measured as ROA or ROE (i.e., net income as a percentage of total assets or equity is much better than average for the industry), even after the revenue loss is accounted for.

After coastal revenues were subtracted from net income (to approximate the shutting in of all of their coastal production), the four firms still showed adequate to good returns based on lowest quartile benchmarks for the industry. Note that the cost of plugging and abandoning wells was not included, but the reductions in the tax burden due to lost coastal revenues also are not considered.

Nine firms, shown in the last two columns in Table 6-8, might realize impacts from the regulation. Three firms are expected to experience some impacts, but not to the extent that firm failure is likely. Six other firms might be substantially affected, but not enough information is provided in the survey to judge whether this is true.

Four firms out of these six questionable firms either have a very small stake in the wells they operate or have no stake and are operators only. Since none of the affected wells were surveyed, whether these wells would be profitable to operate once the regulation is promulgated could not be determined. It is likely that little if any of the increased operating costs would be borne by these firms. If the wells cease to operate, however, the operators would cease to receive revenues for operating these wells. Thus, the impact to these firms might range from minor to major (i.e., firm failure).

Thus, a range of 0 to 6 firms might experience firm failure, under either the improved gas flotation option or the zero discharge option, out of a total of 58 operators examined in this analysis. Since there are a total of 122 operators discharging, or roughly twice the number of operators examined (58 operators screened), the number of firms experiencing firm failure for all discharges is extrapolated to be a range of 0 to 12 firms (and those estimated to be baseline firm failures, represented by 5 initial and 4 subsequent assessments of firm failure, total 18 firms). The upper estimate assumes that firms for which information is lacking will be substantially

affected. Thus, this range might overestimate the impacts considering the level of uncertainty associated with the majority of observations (e.g., some of these respondents might not be appreciably affected if the wells do not shut in and costs are passed through to several owners). Based on the total number of firms estimated to be operating in the Gulf of Mexico in the postcompliance scenario—435 firms minus 18 baseline failures, or 417 firms—these 0 to 12 potentially substantially affected firms are 0 percent to 2.9 percent of the Gulf of Mexico (Texas and Louisiana) segment of the oil and gas industry.

6.5 REFERENCES

Avanti. 1992. Economic Analysis for the NPDES General Permits for Oil and Gas Production Operations in Coastal Texas and Louisiana: Produced Water. Prepared for the U.S. Environmental Protection Agency. July 21.

U.S. Environmental Protection Agency. 1994. Memorandum from Jamie McIntyre, SAIC, to Allison Wiedeman, Revised Produced Water Discharge Volumes for the Gulf of Mexico. Sept. 27, 1994. [To be updated].

SECTION SEVEN

EMPLOYMENT AND COMMUNITY-LEVEL IMPACTS

This section of the EIA assesses employment and community-level impacts resulting from compliance with the proposed effluent limitations guidelines for the coastal oil and gas industry. Impacts from BAT options only are discussed here. Section Ten discusses impacts from NSPS options. Compliance imposes costs at both the well and the firm levels that might result in well shut ins and firm failures and thereby a loss in employment. This primary loss in employment can lead to reduced production in the industries that supply inputs to the coastal oil and gas industry, thus, leading to secondary employment losses. These secondary losses are calculated by using product input-output tables that take into account geographic and industrial patterns and the associated employment changes. When total primary and secondary losses are compared to employment levels in the communities in which the coastal oil and gas industry operates, community-level impacts can be determined. These losses are offset to some extent, however, by the need to hire workers to manufacture, install, and maintain the pollution control equipment. This increase in economic activity results in employment gains in the related industries and is factored into this analysis.

The analysis in this section is divided into three parts. Section 7.1 examines primary and secondary employment losses, presenting the methodology and results of the employment losses and community-level impacts resulting from baseline and postcompliance well shut ins and firm failures. Section 7.2 analyzes labor requirements and potential employment benefits from the manufacture, installation, and maintenance of the necessary pollution control equipment. Section 7.3 presents the net employment impacts of the proposed regulation.

7.1 PRIMARY AND SECONDARY EMPLOYMENT LOSSES

7.1.1 Introduction

Primary employment losses occur only within the portion of the coastal oil and gas industry that discharges wastes as of the effective date of the rule. Secondary impacts include employment losses in other industries providing inputs to the coastal oil and gas industry and other supporting industries such as community-based services that lose income when layoffs occur; these losses would result from any significant decline in demand for inputs as well as from regional reductions in personal income.

Primary and secondary employment losses are summed to obtain the total impact on community employment levels resulting from implementation of the effluent guidelines. Although secondary employment losses do not necessarily occur at the community level (since national multipliers cannot differentiate between input sources within and outside the community), they are included in this analysis to present a conservative estimate of all potential employment losses.

7.1.2 Methodology

7.1.2.1 Primary Employment Losses

Primary employment losses consist of employee layoffs associated with the first-year well shut ins and production losses in later years from loss of well economic life estimated in the production loss analysis, and firm failures in the firm-level analyses. These job losses are estimated from survey data on annual employment hours.

Two types of employment losses (measured in hours) are estimated and summed to estimate total employment losses: Losses are calculated for first-year well shut ins and firm failures. The analysis also looks at impacts from shortened well productive lifetimes, but this impact is not added to first-year losses as discussed below. Numbers of employees per well on

average in the coastal oil and gas industry in the Gulf of Mexico were estimated based on Section 308 survey data and total 1.16 full-time equivalents (FTEs) (4,675 Gulf of Mexico wells divided by 5,403 Gulf of Mexico employees reported in the Section 308 survey). This estimate is considered high because some operators might be reporting secondary employment (e.g., well service portions of their business, or drilling), not just oil and gas production employment, in their financial data. For Cook Inlet, the same methodology is used; that is, numbers of employees reported in the Section 308 survey are divided by numbers of wells (794 employees and 237 wells = 3.2 employees per well). First-year well or platform shut ins were assumed to be associated with the direct loss of this number of employees aggregated over all first-year shut ins.

Later-year production losses also result in the same per-well employment losses; however, because these losses take place in the future, these losses are not added to first-year loses, but some sense of the impact of these effects is determined. The decline in employment is averaged over the baseline and post-compliance well lifetimes to determine an incremental change in employment. This production effect assumes that, in the worst case, no new production takes the place of wells that shut in in later years, both in the baseline and post-compliance, and that all discharging wells in the baseline have a life of 15 years (wells) and 11 years (platforms in Cook Inlet) after 1996 (the average baseline productive life), and all discharging wells (or platforms) have a post-compliance life of 10 years (the average postcompliance productive life in both the Gulf and Cook Inlet). The production loss effect on employment is not added to first-year losses because the dislocation effects are not the same; the impacts are qualitatively different. In the production loss cases, natural attrition of jobs through retirement or change of careers might absorb the employment decline because they are not sudden or unpredictable, whereas for first-year shut ins, more severe dislocations can occur. The effect is, however, computed as part of a present value analysis (i.e., loss of a future FTE is treated as a smaller impact than the loss of a current FTE in the same manner that a dollar today is considered to be worth more than a dollar tomorrow) and results are presented on the basis of annual lost FTEs.

Firms also are analyzed to determine whether they are likely to fail under the various regulatory options. If a firm is shown to be likely to fail, it is assumed that some firm-level employment is lost. Note that wells that do not shut in as a result of the proposed guidelines are

assumed to be sold intact with no loss of employment when their operator fails.[1] Thus, no additional employment losses are associated with firm failure beyond administrative and other nonproduction personnel. It is difficult to estimate the proportion of nonproduction employment that might be affected, however (other areas of business that could be sold intact rather than liquidated are not surveyed in sufficient detail). At maximum, all nonproduction employment can be assumed to be lost with a firm failure. This estimate of firm-level employment losses also is added to the number of employee losses projected under the first-year shut in analysis.

Total employee hours lost because of well shut in or firm failure are expressed in FTEs assuming that 2,080 hours (52 weeks/year x 40 hours/week) equals 1 FTE. The analysis is divided into two stages. The first stage analyzes the employment losses associated with baseline well shut ins and firm failures (i.e., those shut ins and failures that are expected to occur even without the proposed effluent guidelines). The second stage calculates the employment losses associated with shut ins, declines in economic life, and failures associated with compliance with the selected options. These postcompliance losses in employment are then converted into FTEs.

7.1.2.2 Secondary Employment Losses

Secondary losses in employment occur in other industries providing inputs to the coastal oil and gas industry and are caused by reduced demand for these inputs. Secondary impacts are assessed through multiplier analysis, which measures the extent of impacts in other industries as a function of impacts in the primary industry. Multiplier analysis provides a straightforward framework as long as the direct effects are small to the industry and certain limiting assumptions about technology are valid (e.g., constant returns to scale, fixed input ratios).

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[1]This assumption follows from assuming a fixed level of productivity (producing wells per employee). Given that the wells in question are shown to be productive and assuming that a fixed number of employees are needed to operate them, any losses in employment are expected to be temporary since firms acquiring new wells would most likely need to expand their employment. The costs associated with dislocations and relocations should not be great, however, since the wells remain in the same geographic area, and operating personnel would most likely be hired locally.

The multiplier used in this analysis is based on input-output tables developed by the U.S. Department of Commerce, Bureau of Economic Analysis (BEA, 1992). The BEA multipliers are estimated using the Regional Industrial Multiplier System (RIMS II) developed by the Regional Economic Analysis Division of the BEA. The multipliers reflect the total national change in the number of jobs given that a change in the number of jobs for a particular industry occurs.[2]

The multipliers are used to measure the impact of several employment effects. In addition to direct employment losses, the proposed guidelines might generate other employment losses through two mechanisms—induced and indirect employment effects. Employment effects can be expected to occur in the industries that are linked to the oil and gas production industry; these effects are termed "indirect" employment losses. For example, an operator might purchase pumps and oil production tanks or other intermediate goods and services from other firms and sectors of the economy. Thus, decreased economic activity associated with hydrocarbon production has the potential to decrease activity and employment in these linked firms and sectors. Second, the decreased payments to labor in the directly and indirectly affected industries will lead to decreased purchases from consumer-oriented service and retail businesses, which in turn will lead to reduced labor demand and employment losses in those businesses. These effects are termed "induced" or secondary employment losses. The multipliers measure the total primary and secondary employment losses associated with direct, indirect, and induced employment effects.

In this analysis, the industry directly affected is the Crude Petroleum and Natural Gas Industry (SIC 131).[3] The multiplier (measuring direct, indirect, and induced employment effects) reported by BEA for this industry is 2.78 for Louisiana and 3.02 for Texas.[4] The

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[2]Employment multipliers for a given industry show the number of full- and part-time jobs that the industry provides, both directly and indirectly, given a $1 million change in final demand.

[3]Multipliers based on direct employment changes are available at an aggregated industry level only.

[4]The use of this national multiplier might overstate the number of jobs affected within the community because some of the inputs might be from sources outside the community or even outside the country. No multipliers that differentiate among the locations of input sources are known to exist.

average of these two states' multipliers is 2.86. Alaska's multiplier is 2.78.[5] The total number of job losses, both primary and secondary, is computed as the primary losses in coastal oil and gas industry jobs (measured in FTEs) multiplied by the relevant multiplier:

Total job losses in the Gulf Coastal region	=	2.86	*	Primary losses in the Gulf Coastal oil and gas industry
Total job losses in the Cook Inlet region	=	2.78	*	Primary losses in the Alaska Coastal oil and gas industry

These secondary losses are calculated both for the baseline analysis and for each option, postcompliance.

7.1.2.3 Measuring Impacts at the Community Level

The significance of employment losses on the community is measured by their impact on the community's overall level of employment. Data necessary to determine the community impact include the community's total labor force and employment rate. Because the exact locations of the affected Gulf of Mexico wells and firms are not known, employment losses are assumed to accrue to an average county defined by the average employed population and employment rate in the affected Gulf of Mexico region counties and parishes, which is a very conservative measure of impact since it is highly unlikely that only one county would be affected by all primary and secondary employment losses attributed to the proposed guidelines. The community employment information used in this analysis is from the end-of-year 1992, as estimated by the Bureau of Labor Statistics. For purposes of this analysis, the community is defined as the county or parish in which the affected firms or wells are located. In Alaska, oil and gas production personnel tend to be somewhat isolated from any one community; many are transient. It also is possible that these personnel might be transferred within the firm rather than laid off. A community-level impact analysis is not performed for Alaska operations.

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[5]Use of statewide multipliers to apply to a small region could overstate secondary employment losses.

This analysis is not divided into a baseline and postcompliance analysis because subtracting baseline employment losses from existing employment in the county or parish with the smallest employed population makes this analysis unnecessarily conservative.

EPA considers an increase in the community employment rate due to compliance with the regulation equal to or greater than 1 percent a significant impact. This impact would correspond to a considerable change in the community employment rate.

7.1.3 Results—Employment Impacts From BAT Options

7.1.3.1 Baseline Losses: Primary and Secondary Employment Losses

As discussed above, employment losses are counted when a well shuts in (100 percent of the per-well employment), and when a firm fails (100 percent of nonproduction employment). Impacts due to reductions in well lifetimes are also determined.

Table 7-1 presents the results of primary employment losses in the baseline. Total current Gulf employment is estimated to be 5,403 FTEs and total current Cook Inlet employment is estimated to be 794 FTEs, for a total of 6,197 workers.[6] As Table 7-1 shows, before any compliance costs are incurred, 281 jobs are estimated to be lost, all occurring in the Gulf of Mexico region. These 281 losses are associated with 195 wells shut in and 10 estimated baseline firm failures.[7] Thus, 4.5 percent of existing employment (6,197 FTEs) is expected to be lost even without considering any of the regulatory options. The adjusted baseline employment in the Gulf is, thus, 5,122 FTEs, although in Cook Inlet, no adjustments are necessary. Total adjusted baseline employment for the affected coastal region is therefore 5,916 FTEs. The

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[6]This total is for the affected portion of the coastal oil and gas industry. Employment at other coastal oil and gas firms not affected by the proposed effluent guidelines (e.g., operators on the North Slope) is not counted here.

[7]These calculations are as follows: It is assumed that 1.16 FTEs are required to operate a well. First-year shut-ins total 195 wells, thus 1.16 x 195 equals 226 FTEs. Another 86 FTEs are lost through baseline firm failures.

TABLE 7-1

BASELINE AND POSTCOMPLIANCE EMPLOYMENT LOSSES (FTEs)

Option	Gulf of Mexico			Cook Inlet			Total Employment Losses All Regions	Mid-point of Employment Losses
	Losses from Immediate Shut-ins	Losses from Firm Failure	Total Employment Losses	Losses from Shut-ins	Losses from Firm Failure	Total Employment Losses		
Produced Water								
Option #1	0	0	0	0	0	0	0	0
Option #2	49	0-104	49-153	0	0	0	49-153	101
Option #3	129	0-104	129-233	0	0	0	129-233	181
Option #4	129	0-104	129-233	0	0	0	129-233	181
Option #5	129	0-104	129-233	109	0	109	238-342	290
Drilling Waste								
Option #1	0	0	0	0	0	0	0	0
Option #2	0	0	0	0	0	0	0	0
Option #3	0	0	0	0	0	0	0	0
Selected Options Combined								
Option #4-Produced Water, Option #1, #2, or #3-Drilling Waste	129	0-104	129-233	0	0	0	129-233	181
Baseline								
Baseline	226	86	281	0	0	0	281	NA

baseline analysis predicts that primary and secondary job losses will total 804 FTEs using the multiplier of 2.86 (as discussed in Section 7.1.2). These baseline losses constitute an insignificant portion of national employment (which totaled approximately 117.6 million in 1992) and have a negligible impact on national-level employment rates (impacts on a more local basis are discussed later in this section).

7.1.3.2 Postcompliance Losses: Primary and Secondary Employment Losses

Table 7-1 presents employment losses by region and by type of loss for each of the regulatory options considered in this analysis for produced water and drilling waste. Note that impacts from controls on other waste streams are considered to have a negligible impact on employment because of their negligible impacts on firm failure and well production.

Gulf of Mexico Produced Water—Under Option #2 (improved gas flotation) losses due to first-year shut ins total 49 FTEs (based on 42 wells shutting in). Losses in productive life are associated with labor impacts happening more than a decade away. Because employees have ample warning and because of natural attrition as employees change jobs will have time to occur, it is unrealistic to compare these losses to immediate job losses. Thus, this EIA calculates a loss to acknowledge the potential for future impacts, but these losses are not added to the immediate losses anticipated as a result of the rule. A total of 1,561 FTEs[8] are assumed to be associated with discharging wells in the baseline. These 1,561 FTEs are assumed to be lost by year 15 in the baseline (assuming no new discharging production is developed and assuming that the maximum well life for all wells is 15 years [longer well lives will make all percentages smaller]). Over a 15-year period then, at least 30 percent of total Gulf adjusted baseline employment of 5,122 will be lost (assuming constant employment levels among nondischarging operations), an average of about 2 percent per year. This same loss would occur over 10 years under the improved gas flotation option, an average of about 3 percent per year. The difference is 1 percent per year.

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[8]1,588 discharging wells x 1.16 minus 281 baseline FTE losses equals 1,561 FTEs serving discharging wells.

Another way to view this potential loss is to determine an annual loss of FTEs using the difference in losses between years 10 and 15 and then annualizing the present value of these losses. An annual loss of 337 FTEs is computed using this method, but this estimate is very high because all production does not cease after 15 or 10 years. If wells are shut in on the basis of some statistical distribution, then only a certain proportion will have ceased discharging at the end of the average lifetime. If well shut in occurs in a normally distributed pattern, only 50 percent of the wells will have shut in at the end of the average lifetime. Thus, only 169 FTEs (half the initial estimate) would be lost annually if this is the case. Even this number is high because under a normal distribution, well shut ins would be relatively infrequent in the first few years and would peak at the average lifetime, leading to a smaller discounted loss in FTEs. Therefore, annual losses in FTEs resulting from declines in well lifetimes are expected to range up to 337 FTEs, but in fact are probably closer to 169 FTEs or fewer.

Firm-level losses range from 0 to 104 FTEs based on the estimate of 0 to 12 firms failing. Total losses (firm-level and losses from first-year shut ins) are, thus, estimated to range from 49 to 153 FTEs (primary and secondary losses are estimated to total 140 to 438 FTEs), or 1.0 to 3.0 percent of postbaseline Gulf of Mexico employment.

Under Options #3 through #5 (all zero-discharge options for the Gulf of Mexico), losses from first-year shut ins total 129 FTEs, and the impact associated with loss of economic lifetime[9] is also approximately an additional 1 percent employment decline per year. Firm losses continue to range from 0 to 104. Total losses range from 129 to 233 FTEs (2.5 to 4.5 percent of postbaseline Gulf of Mexico employment). Primary and secondary losses associated with Options #3 through #5 are 5 FTEs. The midpoint of these losses is used for comparison with employment gains (181 primary losses and 518 primary and secondary losses).

Cook Inlet Produced Water—Under Option #2 (improved gas flotation), no losses associated with firm failures are expected. No platforms will shut in during the first year;

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[9]Roughly 5 years are lost under produced water Options #2 through #5 (the difference of a few months between options makes negligible changes in the results). The same methodology used to compute losses associated with loss of economic life under the gas flotation option is used here.

however, one platform cannot drill three wells that were planned, resulting in 10 FTES that potentially will not be added to the workforce. This impact is not considered an employment loss but is used to reduce the estimate of employment gains as discussed in Section 7.2. Only 0.4 years of productive life is expected to be lost on average in Cook Inlet; thus, impacts on employment from platforms closing earlier than in the baseline are negligible. No primary or secondary employment losses are anticipated.

Under Option #3, no losses are expected because Cook Inlet operations are required only to meet BPT requirements.

Under Option #4, losses are expected to be identical to those for Option #2, since Cook Inlet operations must meet the same requirement as under Option #2.

Under Option #5, three platforms shut in, but no years of productive life (on average) are lost on nonclosing platforms. These impacts are associated with employment losses of 109 FTEs, or 13.7 percent of Cook Inlet employment. Primary and secondary employment losses are estimated to total 303 FTEs.

Cook Inlet Drilling Waste—Option #2 will result in no platforms shutting in during the first year, and no productive life lost; thus, no employment is lost under this option (although three wells will not be drilled under this option that would have been drilled in the baseline scenario). No firm failures are expected. Option #3 is estimated to result in no platforms shutting in, but six wells will not be drilled. Employment impacts associated with the reduction in planned drilling and production totaling 20 FTEs are measured as losses in employment gains only (see Section 7.2). A 1-year productive life loss is expected, but the impact of this loss on employment is expected to be minimal. No firm failures are expected; thus, no primary or secondary employment losses are anticipated.

All Regions—Total employment losses associated with produced water options (not including Option #1) range from 101 FTEs (midpoint estimate) for Option #2 (1.7 percent of combined Gulf of Mexico and Cook Inlet employment) to 290 FTEs for Option #5 (4.9 percent of combined adjusted Gulf of Mexico and Cook Inlet baseline employment, which is estimated to

be 5,916 FTEs).[10] The selected options (Option #4, produced water, and Options #1 through #3, drilling waste) are associated with losses totaling 181 FTEs (or 3.1 percent of combined Gulf of Mexico and Cook Inlet employment). Based on the multiplier of 2.86 percent for the Gulf of Mexico, total primary and secondary losses would total 518. Table 7-1 summarizes all primary employment losses by option.

7.1.3.3 Community-Level Impacts

Among the counties and parishes in Texas and Louisiana, the average employed population is 88,600 and the average employment rate is 46.19 percent (based on data from BLS, 1992). Gulf of Mexico losses under Option #4 for produced water, both primary and secondary, total 518 FTEs (181 FTEs x 2.86). If all these employment losses were concentrated only in this average county, this county's employment rate would decline by, at most, 0.3 percent (if the high end rather than the midpoint of the employment loss range is used). Note, however, that the concentration of these employment impacts in only one county is highly unlikely. Furthermore, the use of statewide multipliers to apply to a local area compounds the potential overestimate of impacts at the community level. The decline in employment rate in any one community in the Gulf of Mexico region will be much less than this; thus, it is unlikely that any county's employment rate would change by more than 1 percent.

7.2 LABOR REQUIREMENTS AND POTENTIAL EMPLOYMENT BENEFITS

7.2.1 Introduction

Firms will need to install and operate pollution control systems to comply with effluent limitations guidelines for the coastal oil and gas industry. The manufacture, installation, and operation of these systems will require use of labor resources. To the extent that these labor

[10]That is, 5,122 FTEs remaining in the Gulf of Mexico after the baseline analysis plus 794 Cook Inlet employees.

needs translate into employment increases in affected firms, effluent guidelines for the coastal oil and gas industry have the potential to generate employment benefits. If realized, at a minimum these employment benefits might partially offset the employment losses that are expected to occur. The employment effects that would occur in the manufacture, installation, and operation of treatment systems are termed the "direct" employment benefits of the rule. Because these employment effects are directly attributable to the coastal oil and gas industry rule, they are conceptually parallel to the employment losses estimated as a result of the rule. This section looks at the *benefits* associated with the selected regulatory options only.

As for employment losses, employment gains are associated with direct, indirect, and induced components (see Section 7.1.2) resulting from the need to manufacture, install, and operate pollution control equipment.

In view of these possible employment benefits, EPA estimated the labor requirements associated with the proposed regulatory options as outlined in Section Four. The following discussion summarizes the findings from this effort. Labor requirements—and thus, the possible employment benefits—were estimated in two steps. First, the direct employment effects associated with the manufacture, installation, and operation of the coastal oil and gas industry compliance equipment were estimated. These effects are discussed in Section 7.2.2. Second, EPA considered the additional employment effects that might occur through the indirect and induced effect mechanisms outlined above; these effects are discussed in Section 7.2.3.

7.2.2 Estimating Direct Labor Requirements

As discussed above, an effluent guideline for the coastal oil and gas industry will create demand for labor services for manufacturing, installing, and operating compliance equipment. Each of these components of direct labor requirements are analyzed separately. The sum of the estimated requirements for the three labor categories represents the estimated total direct labor requirement, and, thus, the potential direct employment benefit, from compliance with the effluent guidelines.

7.2.2.1 Direct Labor Requirements for Manufacturing Compliance Equipment

The direct labor requirements for manufacturing compliance equipment are estimated based on the cost of the equipment and labor's expected contribution to the equipment's value in its manufacture. Labor's contribution was estimated in dollars and was converted to an FTE based on a yearly labor cost. Each component of the calculation is discussed below.

Cost of Compliance Equipment

The cost of purchasing and operating compliance equipment was presented in Section Four for Option #4, produced water, and Options #2 and #3, drilling waste. Compliance equipment requirements and their associated costs were used as provided in the Development Document (U.S. EPA, 1995). For the labor requirements analysis, compliance costs and their associated labor requirements were considered. Because costs were derived for each discharging treatment facility in the Gulf of Mexico and because it is not possible to determine which treatment facilities will continue to operate postcompliance on an individual basis, all facilities were assumed to install this equipment (this assumption might slightly overstate the employment benefits of the proposed regulation but is consistent with the assumption that all compliance costs will be incurred). In Cook Inlet, baseline effects could be factored into the analysis. The portion of total capital cost assumed to be associated with equipment purchases is estimated at 78 percent for Gulf of Mexico operations.[11] This proportion also is applied to Alaska (equipment costs are greater in Alaska, but so are installation costs). The total estimated one-time capital equipment cost in 1992 dollars (a one-time cost) for complying with the selected regulatory options is $62.7 million in the Gulf of Mexico and $6.3 to $8.1 million in Cook Inlet (depending on drilling waste option), for a total of $69.1 to $70.8 million.

[11]This estimate is based on an average percentage for Louisiana and Texas presented in SAIC's Injection Cost Study (1995). The other 22 percent is installation.

Labor's Expected Contribution to the Equipment's Value

Input-output tables compiled by the Bureau of Economic Analysis (BEA) provide information on the composition of inputs used to produce the outputs of industries in the U.S. economy (BEA, 1991a,b [1982 data]).[12] The inputs tallied in the input-output tables include the purchase of intermediate goods, materials, and services from other industries as well as the use of labor by the subject industry. In particular, the *direct requirements* matrix identifies the value of each input, including labor, that is required to produce a one-dollar value of output for a subject industry. From discussions with the EPA technical contractor on this effluent guidelines project, the "Machinery, Except Electrical" industry (SIC 3234) was identified as the industry with output that most nearly matches the types of equipment needed for compliance with the coastal oil and gas industry effluent guidelines. From the Regional Multipliers Handbook (BEA, 1992), labor input accounts for an average of $0.2678 of each dollar of output value from the "Machinery Except Electrical" industry.[13] Multiplying labor's share of output value (0.2678) times the value of equipment purchases for complying with the rule yields labor's contribution to manufacturing the compliance equipment, measured in terms of gross compensation.

The estimated total cost of purchasing compliance equipment is $62.7 million in the Gulf of Mexico; however, this includes costs for treatment facilities with wells that will shut in according to the baseline and postcompliance scenarios. The estimated total costs of purchasing compliance equipment in Cook Inlet (not including ARCO's costs for disposing of drilling waste)[14] is $6.3 to $8.1 million depending on drilling waste option chosen. Labor's contribution is estimated to be $16.8 million for the Gulf of Mexico (0.2678 x $62.7 million) and $1.7 to $2.2 million for Cook Inlet ($6.3 to $8.1 million x 0.2678).

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[12]The 1982 tables are the most current information on the interindustry input-output structure of the U.S. economy.

[13]Since oilfield equipment was assumed to be locally available or near the Gulf of Mexico area, multipliers for Texas and Louisiana were averaged. The same multiplier was used for Alaska since it is assumed the equipment is shipped from the Gulf of Mexico area.

[14]The Arco project is very tentative. Costs have been included, but impacts are not addressed; so employment gains are not counted for this activity.

The manufacture of compliance equipment is considered a one-time event that occurs at the beginning of industry's compliance activities. Accordingly, the labor requirements for manufacturing compliance equipment should be viewed as a one-time requirement. Elsewhere in this economic impact analysis, the labor effects associated with impacts are presented on an annual basis, with the expectation that these job effects would persist over the period of analysis. Thus, for consistent assessment of the possible labor requirement effects from manufacturing compliance equipment, it was necessary to annualized the one-time labor effect. Consistent with the annualization procedures elsewhere in the economic impact analysis, the one-time labor compensation values of $16.8 million for the Gulf of Mexico and $1.7 to $2.2 for Cook Inlet were annualized over a 10-year period at a social discount rate of 7 percent as recommended by OMB (OMB, 1992). The social discount rate is used rather than the industry discount rate because the social impacts are being assessed here, and not impact on industry. The resulting annual value of gross labor compensation in manufacturing compliance equipment is $2.4 million for the Gulf of Mexico and $0.2 to $0.3 million for Cook Inlet.

Conversion to Full-Time Employment Equivalent Basis

To convert the gross payment to labor to a full-time employment equivalent basis, the payment to labor was divided by an estimated yearly labor cost. This cost is based on the wage rate for the "Machinery Except Electrical" industry, which is $12.50 per hour (personal communication between ERG and BLS, September 30, 1994). This usage rate is then used to compute a comprehensive gross labor cost that includes a factor allowing for fringe benefits (e.g., holidays, vacation, and various insurance) and payroll taxes. It is assumed that the gross labor cost is two times the wage rate to account for these items to compute a total hourly labor cost of $25. This cost was calculated in 1992 dollars. Assuming a 2,080-hour work-year, the gross annual labor cost per full-time employment position is $52,000. On a one-time, one-year basis (i.e., not annualized), the $16.8 million (Gulf of Mexico) and $1.7 to $2.2 million (Cook Inlet) of gross annual labor outlay for manufacturing compliance equipment is estimated to require 323 FTEs (Gulf of Mexico) and 33 to 42 FTEs (Cook Inlet). On an annualized basis, the $2.4 million (Gulf of Mexico) and $0.2 to $0.3 million (Cook Inlet) of gross annual labor cost for manufacturing compliance equipment is estimated to require 46 and 5 to 6 FTEs, respectively.

7.2.2.2 Direct Labor Requirements for Installing Compliance Equipment

EPA estimated the direct labor requirements for installing compliance equipment in a similar manner to that used for analyzing the labor requirements for manufacturing compliance equipment. Each component of the calculation is discussed below.

Cost of Installing Compliance Equipment

The cost of installing compliance equipment was not estimated directly; the percentage of installation labor to total capital cost was provided by SAIC (SAIC, 1995). This percentage also was used for Alaska, due to data limitations.

Labor's Expected Contribution to the Equipment's Value

The labor component of total capital cost for installation was derived for the Gulf of Mexico based on SAIC's Injection Cost Study (SAIC, 1995). The average labor component as a percentage of total equipment costs is estimated at 32 percent in the Gulf of Mexico. Because similar data are lacking for Cook Inlet, 32 percent is also used for Cook Inlet. Total labor costs for installation are, thus, estimated to be $20.1 million in the Gulf of Mexico and $2.0 to $2.6 million in Cook Inlet. Annualized labor costs are estimated to be $2.9 million in the Gulf of Mexico and $0.3 to $0.4 million in Cook Inlet.

Conversion to Full-Time Employment Equivalent Basis

Conversion to FTEs is based on the total labor cost of $20.1 million (Gulf of Mexico) and $2.0 to $2.6 million (Cook Inlet), as estimated above given a 2,080-hour labor year and an average wage rate (with a factor of two for fringe and overhead) for oil and gas workers of $27 in the Gulf of Mexico and $31 in Alaska (wage data provided in personal communication between ERG and BLS, September 30, 1994). On a one-time, one-year basis, 357 FTEs (Gulf of

Mexico) and 31 to 40 FTEs (Cook Inlet) are estimated to be required for installing the equipment needed to comply with the selected regulatory options. Annualized over 10 years, the corresponding labor requirement for installing compliance equipment is 51 FTEs (Gulf of Mexico) and 4 to 5 FTEs (Cook Inlet).

7.2.2.3 Direct Labor Requirements for Operating Compliance Equipment

Based on data provided by SAIC (1995), the average percentage of O&M attributable to labor for the Gulf of Mexico compliance costs is about 9.2 percent. As done previously, this percentage also is applied to Alaska. Total O&M for the Gulf of Mexico is estimated at $16.6 million to meet the zero-discharge requirement. For Cook Inlet (not counting any costs for Arco), total O&M is calculated to be $1.0 to $2.9 million. Applying the 9.2 percent factor yields labor's share of this cost: $1.5 million for the Gulf of Mexico and $0.1 to $0.3 million for Cook Inlet. The same labor rates of $27/hour (Gulf of Mexico) and $31/hour (Cook Inlet) used to compute the installation component are used to compute labor requirements for O&M. A total of 27 FTEs (Gulf of Mexico) and 1 to 5 FTEs (Cook Inlet) are calculated.

7.2.2.4 Total Direct Labor Requirements

Summing the three components yields the total direct labor requirements for complying with the proposed coastal oil and gas industry effluent guidelines as represented by the selected regulatory options (see Tables 7-2 through 7-4). On an FTE basis, the estimated total annual labor requirement is 124 FTEs (Gulf of Mexico) and 10 to 15 FTEs (Cook Inlet), for a total of 134 to 139 FTEs. The corresponding total annual estimated payments to labor is $6.8 million (Gulf of Mexico) and $0.6 to $0.9 million (Cook Inlet), for a total of $7.4 to $7.7 million (1992 dollars).

This number must be offset, however, by the employment gains that will not occur as a result of the effluent guidelines. As noted in Section 7.1, some wells will not be drilled under certain regulatory options. A total of 10 to 20 FTEs might not be added to the labor force

TABLE 7-2

ANALYSIS OF POSSIBLE DIRECT EMPLOYMENT GENERATION EFFECTS OF EFFLUENT GUIDELINES FOR THE COASTAL OIL AND GAS INDUSTRY—GULF REGION ($1992)

	Labor Cost Component				Direct Labor Requirement	
	Total Expenditures ($)	Labor's Share of Output Value	One-Time Basis ($)	Annual Labor Cost ($)	One-Time Basis (FTEs)	Annual Basis (FTEs)
Manufacturing	$62,730,344	0.2678	$16,799,186	$2,391,826	323	46
Installation	NE	0.32*	$20,073,760	$2,858,052	357	51
Operation (annually)	$16,629,622	0.092	$1,529,925	$1,529,925	27	27
Total direct labor effects	—	—	$38,402,871	$6,779,803	707	124

*32% of total equipment costs.

NE = Not estimated.

Source: ERG estimates.

TABLE 7-3

ANALYSIS OF POSSIBLE DIRECT EMPLOYMENT GENERATION EFFECTS OF EFFLUENT GUIDELINES FOR THE COASTAL OIL AND GAS INDUSTRY—COOK INLET ($1992)

	Labor Cost Component				Direct Labor Requirement	
	Total Expenditures ($)	Labor's Share of Output Value	One-Time Basis ($)	Annual Labor Cost ($)	One-Time Basis (FTEs)	Annual Basis (FTEs)
	With Option #1 Drilling Waste					
Manufacturing	$6,328,511	0.2678	$1,694,775	$241,298	33	5
Installation	NE	0.32*	$2,025,124	$288,332	31	4
Operation (annually)	$1,035,110	0.092	$95,230	$95,230	1	1
Total direct labor effects with Option #1	—	—	$3,815,129	$624,860	65	10
	With Option #2 Drilling Waste					
Manufacturing	$8,055,878	0.2678	$2,157,364	$307,160	42	6
Installation	NE	0.32*	$2,577,881	$367,032	40	5
Operation (annually)	$1,462,828	0.092	$134,580	$134,580	2	2
Total direct labor effects with Option #2	—	—	$4,869,825	$808,772	84	13

TABLE 7-3 (continued)

	Labor Cost Component				Direct Labor Requirement	
	Total Expenditures ($)	Labor's Share of Output Value	One-Time Basis ($)	Annual Labor Cost ($)	One-Time Basis (FTEs)	Annual Basis (FTEs)
	With Option #3 Drilling Waste					
Manufacturing	$8,055,878	0.2678	$2,157,364	$307,160	42	6
Installation	NE	0.32*	$2,577,881	$367,032	40	5
Operation (annually)	$2,915,602	0.092	$268,235	$270,387	4	4
Total direct labor effects with Option #3	—	—	$5,003,480	$942,427	86	15

*32% of total equipment cost for option (produced water) and relevant drilling waste cost.

NE = Not estimated.

Source: ERG estimates.

TABLE 7-4

TOTAL ESTIMATED DIRECT EMPLOYMENT GAINS:
GULF OF MEXICO AND COOK INLET REGIONS

	Annual Labor Cost			Annual Basis Employment Gains (FTEs)
	With Option #1 Drilling Waste	With Option #2 Drilling Waste	With Option #3 Drilling Waste	
Manufacturing	$2,633,124	$2,698,986	$2,698,986	51-52
Installation	$3,146,384	$3,225,084	$3,225,084	55-56
Operation (annually)	$1,625,155	$1,664,505	$1,798,160	28-31
Total direct labor effects	$7,404,663	$7,588,575	$7,722,230	134-139

under the combined produced water and drilling waste options proposed.[15] Thus, under Option #4, produced water/Option #1, drilling waste, 127 FTEs might be gained; when Option #2, drilling waste, is considered, 125 FTEs might be gained; and when Option #3, drilling waste is considered, 119 FTEs might be gained. To the extent that these labor requirements are manifested as new labor needs in the U.S. economy, these 119 to 127 FTEs have the potential to offset employment losses that might otherwise occur because of the rule. For simplicity, the 119 FTE figure is used to estimate aggregate employment gains here.

7.2.3 Estimating the Secondary (Indirect and Induced) Labor Requirement Effects

In addition to direct labor effects, the coastal oil and gas industry effluent guidelines might also generate labor requirements through the indirect and induced effect mechanisms, thereby generating secondary employment. The secondary effects associated with an economic activity are analyzed by using multipliers. Multiplier estimates generally vary with the industry in which the direct economic activities are expected to occur and with the economic characteristics of the location of the direct activities.

A range of multipliers was used in this analysis to illustrate the possible aggregate employment effects of the effluent guidelines. A recent EPA study used multipliers ranging from 3.5 to 3.9 to calculate the possible indirect and induced employment effects of direct activity investments in general water treatment and pollution control (U.S. EPA, 1993). A study of "clean water investments" commissioned by the National Utility Contractors Association (NUCHA/Apogee Research, 1992) documented total employment effect multipliers ranging from 2.8 to 4.0. Using the midpoint of these latter multipliers (3.4), which falls in the range reported by EPA, the indicated aggregate employment effects associated with the direct labor requirement of 119 FTEs would be 405 FTEs.

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[15]In Section Five, although three wells will jot be drilled under Option #4, produced water, and three or six wells will not be drilled under Options #2 and #3, drilling waste, three of the wells are the same wells under produced water and drilling waste options. Thus six wells is the maximum number affected by the combined options.

A more conservative assessment of these possible employment effects would recognize that the three categories of labor requirements analyzed in Section 7.2.2 are likely to have different indirect labor demand effects. In particular, the direct labor demands for manufacturing and installing compliance equipment result from additional economic activity in those industries. Accordingly, it is reasonable to expect that the additional economic activity in manufacturing and installing equipment will translate into increased activity in the industries that are linked to the direct effect industries and, hence, lead to additional labor demand in those industries through the indirect effect mechanism. In contrast, the increased labor demand in the coastal oil and gas industry for operating compliance equipment does not result from increased economic activity in that industry. As a result, increased labor demand in the coastal oil and gas industry resulting from development of effluent guidelines might not translate into increased labor requirements in the industries that are linked to this industry. In this case, the appropriate employment multiplier for the equipment-operations component of direct labor requirements should exclude the indirect effect mechanism and include only the induced effect mechanism. Multipliers cited in the NUCHA study (Apogee Research, 1992) suggest that a multiplier based only on the induced effect mechanism might fall in the range of 2.4 to 2.9. Using the midpoint of 2.7 for the equipment-operations component of direct labor requirements and the midpoint of the higher 2.8 to 4.0 range (3.4) for the manufacturing and installation components, the estimated aggregate employment effects of the coastal oil and gas industry effluent guidelines would be 397[16] FTEs.

7.3 NET EFFECT OF EMPLOYMENT LOSSES AND GAINS

The primary employment gains (119 FTEs) are expected to partially offset primary employment losses (181 FTEs under the combined regulatory options, regardless of which drilling waste option is chosen). Thus, primary losses might be 62 FTEs. Primary and secondary gains of 397 FTEs are expected to offset partially the primary and secondary loss of 518 FTEs estimated in Section 7.1. The net effect on employment therefore might be 121 FTEs lost. The

[16] 108 x 3.4 + 11 x 2.7. Note that employment gains not realized (20 FTEs) are assumed to be lost from O&M labor.

net employment impact is negligible when compared to national-level employment and will have no impact on national-level employment rates.

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SECTION EIGHT

IMPACTS ON THE BALANCE OF TRADE, INFLATION, AND CONSUMERS

Although the costs and economic impacts of the BAT and NSPS regulations will fall primarily on the coastal oil and gas industry, including its employees, other secondary effects in other sectors of the economy will also occur. Secondary employment effects are discussed in Section Seven, and impacts on federal and state tax revenues are discussed in Section Five. This section reviews the potential effects of regulatory costs on the balance of trade and on inflation and consumers.

8.1 IMPACTS ON THE BALANCE OF TRADE

The United States has now reached the time when oil imports exceed total oil production. OGJ (1995) reports that "for the first time in history, more than half the oil used in the United States in a given year [1994] was imported." A shortage of trained personnel and workover rigs are factors cited as limiting any near-term sizable increase in domestic production (OGJ, 1990a; OGJ, 1990b: and OGJ, 1990c). Indications are that unless domestic demand for oil is curbed, the United States will continue to import a growing percentage of the supply needed to satisfy domestic consumption. This phenomenon is occurring in the absence of any incremental pollution control costs.

The potential loss in production is investigated in Section Five. Under Option #4, for produced water, and with Cook Inlet meeting zero discharge of drilling waste, production declines are only at most 2 percent of total coastal production over the lifetimes of the discharging wells and platforms. This is a relatively small percentage given the estimated annual decline in domestic production of about 3 percent *per year* cited in recent projections (OGJ, 1994). Thus the change in the balance of trade expected from the rulemaking will not be significant compared to changes caused by other factors.

8.2 IMPACTS ON INFLATION AND CONSUMERS

The regulations can lead to higher costs for industry operators. When evaluating this effect on typical companies, ERG did not assume that such companies could raise prices to recover these costs. This assumption would be consistent with the fact that the United States is a price-taker in the world oil market (i.e., the price the companies will receive for their product is determined by the world oil price and not domestic costs). Given the nation's continued growth in demand, supply (and therefore price) is not likely to be controlled domestically (although control by OPEC is still possible). Given the inability of the companies to raise prices in response to increased costs, no substantial impacts on inflation are likely to result from increased costs associated with pollution controls on coastal oil and gas effluents. Therefore, this rulemaking will have no substantial distributional impacts, since consumers of oil products will not be facing higher prices as the result of higher domestic producer costs.

8.3 REFERENCES

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SECTION NINE

REGULATORY FLEXIBILITY ANALYSIS

9.1 INTRODUCTION

The Regulatory Flexibility Act requires the federal government to consider the impacts of proposed regulations on small entities (as defined in 13 CFR Part 121) as part of rulemaking procedures. The goal of the analysis is to ensure that small entities potentially affected by a new regulation will not be disproportionately burdened. The Act acknowledges that small entities have limited resources and makes it the responsibility of the regulating federal agency to avoid, if possible, disproportionately or unnecessarily burdening such entities.

The effluent guidelines and standards for the coastal oil and gas industry will affect how small firms in this industry treat their wastewater. Section 9.2 discusses the analyses that must be undertaken according to EPA guidance; Section 9.3 presents the analyses required for an Initial Regulatory Flexibility Analysis; Section 9.4 presents a profile of the affected small firms; and Section 9.5 determines the firm-level impacts on small firms.

9.2 SUMMARY OF EPA GUIDELINES ON RFA REQUIREMENTS

EPA guidelines now require EPA Offices to perform Regulatory Flexibility Analyses (RFAs) for regulations that have *any* effect on *any* small entities. Formerly, EPA determined whether an RFA should be performed by determining whether the rule in question had a significant economic impact on a substantial number of small entities. When using this approach, EPA would first determine whether the rule did in fact have a significant impact on a substantial number of small entities. With the new approach, EPA can bypass much of this preliminary analysis and proceed more or less directly to addressing the impacts on the affected entities.

EPA's approach is divided into two stages: an Initial Regulatory Flexibility Analysis (IRFA), performed for a proposed rule, and a Final Regulatory Flexibility Analysis (FRFA),

performed for a final rule. Because this EIA on effluent guidelines for the coastal oil and gas industry is being prepared for a proposed rule, an IRFA must be performed at this time.

The IRFA is divided into six requirements:

- Explain why the Agency is considering taking action.
- Succinctly state the objectives of and legal basis for the proposed rule.
- Describe and, where feasible, estimate the number of small entities to which the proposed rule will apply.
- Describe the projected reporting, recordkeeping, and other compliance requirements of the proposed rule, including an estimate of the classes of small entities that will be subject to the requirements and the type of professional skills necessary for preparation of reports or records.
- Identify, to the extent possible, all relevant federal rules that may duplicate, overlap, or conflict with the proposed rule.
- Describe any significant alternatives to the proposed rule that accomplish the stated objectives of applicable statutes while minimizing the rule's economic impact on small entities.

Specific analyses suggested by the guidelines for characterizing impacts include the following:

- A closure analysis (at the firm level) using ratio analysis (see Section Six). To characterize impacts for this IRFA, this section summarizes the information in Section Six, comparing the relative postregulatory health of small firms with that of larger firms.
- A discounted-cash-flow analysis examining the consequences of the annual costs of compliance. This analysis investigates the impacts on cash flow by determining the present value of total compliance costs at a firm as a percentage of the present discounted value of cash flow (in this EIA, cash-flow impacts could not be evaluated since it was not possible in most cases to link specific compliance cost estimates to firms—see Section Six for more explanation).
- A socioeconomic analysis, if the number of affected firms leads to changes in employment conditions, income, social service expenditures, tax revenues, and/or balance-of-trade levels.

The first two analyses are discussed in Section 9.5. Many of the socioeconomic impacts are expected to be minimal because of the very small number of firms affected by the regulation (a very small subset of the oil and gas industry) and because the industry acts as a price taker in the world market (thus, no distributional effects will occur). Nonetheless, potential impacts on communities are discussed in Section Seven and tax revenue effects are discussed in Section Five.

9.3 IRFA INFORMATION REQUIREMENTS

9.3.1 Reasons for Taking Action and Objectives of and Legal Basis for the Proposed Rule

This 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 is proposing effluent limitations guidelines and standards for the control of discharge of pollutants for the coastal subcategory of the Oil and Gas Extraction Point Source category. The regulations also are being proposed pursuant to a Consent Decree entered in *NRDC et al. v. Reilly* (D.D.C. No. 89-2980, January 31, 1992), and are consistent with EPA's latest Effluent Guidelines Plan under Section 304(m) of the CWA (see 59 FR 44234, August 26, 1994).

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. Section 304(b)(1) authorizes EPA to issue BPT effluent limitations guidelines. The existing effluent limitations guidelines, which were issued on April 13, 1979 (44 FR 22069), are based on the achievement of BPT. Section 304(b)(4) authorizes EPA to issue BCT guidelines; Section 304(b)(2) authorizes EPA to issue BAT guidelines; Section 306 authorizes EPA to issue NSPS; and Section 307(b) authorizes EPA to issue PSES and PSNs.

9.3.2 Estimates of the Affected Population of Small Businesses

A basic step in conducting an IRFA is to estimate the affected population. Small firms are defined in 13 CFR Part 121 either by their employment size or their revenues. In SIC 131, small firms are defined as those employing 500 or fewer persons. For greater awareness of where impacts are occurring, this analysis further breaks down small firms into employment groups. These groups are as follows:

- 0-9 employees
- 10-49 employees
- 50-99 employees
- 100-500 employees
- >500 employees

This analysis therefore will consider all categories, except the >500 employees category, as small for the purposes of identifying the affected small business population.

The number of firms in each grouping are presented in Table 9-1. These numbers reflect all firms in the survey universe including those expected to fail in the baseline. As the table shows, out of 435 firms in the estimated survey universe, 86 percent are estimated to be small firms. The largest percentage of firms is in the 0-to-9 employees size group (40.0 percent of all firms in the survey universe).

9.3.3 Projected Recordkeeping and Reporting Requirements

The proposed effluent guidelines for the coastal oil and gas industry supplement existing BPT regulations that were promulgated in 1979. As such, recordkeeping requirements are already in place; thus, no incremental recordkeeping and reporting will be required. In fact, firms that cease discharging wastes will no longer have to monitor oil and grease and other pollutants covered by the existing BPT regulations in their discharged waste streams. Thus,

TABLE 9-1

NUMBERS OF COASTAL OIL AND GAS FIRMS BY SIZE*

Employment Size Category	Number of Firms	Percent of Total
0-9 employees	174	40.0
10-49 employees	107	24.7
50-99 employees	40	9.3
100-500 employees	51	11.6
>500 employees	63	14.4
Total	435	100.0

*Extrapolated to 435 firms based only on survey responses with data. Not that this extrapolation proably overestimates large firms, since it is likely that nearly all large coastal operators were surveyed.

Source: ERG estimates based on Section 308 survey responses.

recordkeeping and reporting requirements could become less burdensome for many firms in the industry. This benefit of the regulation is not quantified.

9.3.4 Other Federal Requirements

EPA is aware of no federal rules that duplicate, overlap, or conflict with the proposed effluent guidelines for the coastal oil and gas industry.

9.3.5 Significant Alternatives to the Proposed Rule

For produced water in the Gulf of Mexico (the only location of small firms), EPA investigated three options. Option 1 would set BAT equal to BPT; this no-action approach would not meet the stated objectives of the Clean Water Act. Option 2 would require coastal operations to meet the same requirements as offshore operations; this option would not be substantially less expensive, nor would it provide for substantially fewer measurable impacts than the selected option, which requires zero discharge. Thus, Option #3, although not the lowest-cost option, was selected because it is technologically available, economically achievable, and has acceptable nonwater quality environmental impacts. The selected options for all other waste streams were determined to have very minimal impacts on the few affected firms, and impacts from potentially less expensive options were not measurably different from those associated with the selected options. In all cases, no-action alternatives were considered not to meet the objectives of the Clean Water Act.

Many firms in the smaller size groups already achieve no discharge of all wastes, and impacts overall are low for all size groups (see discussion in Section 9.5). Thus, although impacts are somewhat more pronounced among certain small firms, they are not considered excessively disproportionate.

Having considered the impacts to small firms where possible, the Agency believes the stated objectives of the Clean Water Act are met with this proposed rule.

9.4 PROFILE OF SMALL COASTAL OIL AND GAS FIRMS

Tables 9-2 through 9-4 provide general information about the financial condition of small coastal oil and gas firms in the Section 308 survey as compared to large firms (all firms are considered here, not just the financially healthy firms). The operators covered in this analysis are just the Gulf of Mexico operators; all Cook Inlet operators are considered large firms. As Table 9-2 shows, median total assets and liabilities rise with size, as does median net income in most instances. Note, however, the relatively poor performance of the larger small firms (i.e., the 100-to-500 employees group). In general, small firms tend to have lower ROA than large firms, although it is variable among the groupings of small firms. Some variability might be caused by a larger proportion of S corporations and other types that are not liable for corporate income taxes, leading to higher net incomes reported among certain small firms (the smaller the firm, the likelier that it is not a standard corporation). In general, as reported in Section Three, ROA for both small and large Gulf of Mexico firms is typically between the industry median (3.5 percent) and the lowest quartile (-1.3 percent) (Dun & Bradstreet, 1993), indicating a weak but not poorly performing group of firms. Again, the weakest group is the group with 100 to 500 employees, although median ROA for this group is still above the lowest quartile for the industry.

Predictably, average costs and revenues tend to rise with the size of the firm (see Table 9-3). Coastal oil and gas revenues constitute 2.4 percent of total income in large firms, whereas in small firms the proportion rises as high as 15.0 percent in the 0-to-9 employees size group, indicating that these firms hold fewer diverse interests than firms in other size groups. A diversity of holdings can minimize impacts from the proposed effluent guidelines for the coastal oil and gas industry. The less diverse holdings among the 0-to-9 employees size group make these firms somewhat more vulnerable to impacts from the proposed effluent guidelines than other firms in the Gulf of Mexico.

As discussed in Section Six, all ten firms (extrapolated) that were determined to fail in the baseline on the basis of negative equity and working capital, as well as the additional eight firms determined to fail in the baseline during the detailed survey analysis, are small firms. No large firms are expected to fail in the baseline. Only about 5 percent of all small firms (4 percent of all firms) are expected to fail in the baseline.

TABLE 9-2

PROFILE OF COASTAL OIL AND GAS FIRMS BY SIZE:
FINANCIAL INDICATORS
($000)

Employment Size Category	Median Total Assets	Median Total Liabilities	Median Net Income	Median Baseline ROA
0-9 employees	$486	$275	$1	0.0020
10-49 employees	$13,536	$8,664	$59	0.0104
50-99 employees	$38,776	$18,127	$925	0.0282
100-500 employees	$256,820	$171,660	($518)	-0.0023
>500 employees	$1,904,967	$920,600	$27,313	0.0180
All small firms (Less than or equal to 500 employees)	$4,624	$2,086	$10	0.0080
All firms	$9,129	$5,235	$16	0.0108

Source: ERG estimates based on Section 308 survey results.

TABLE 9-3

PROFILE OF COASTAL OIL AND GAS FIRMS BY SIZE:
OIL AND GAS COSTS AND REVENUES
($000)

Employment Size Category	Median Coastal Oil and Gas Costs*	Median Coastal Oil and Gas Revenues	Median Total Revenues	% Coastal Revenues to Total Revenues
0-9 employees	$38	$68	$449	15.0
10-49 employees	$83	$251	$6,034	4.2
50-99 employees	$245	$786	$14,301	5.5
100-500 employees	$580	$2,327	$83,655	2.8
>500 employees	$6,518	$25,541	$1,067,880	2.4
All small firms (Less than or equal to 500 employees)	$84	$178	$2,581	6.9
All firms	$107	$259	$4,921	5.3

*Operating costs only.

Source: ERG estimates based on Section 308 survey results.

TABLE 9-4

BASELINE FIRM FAILURES BY SIZE OF FIRM

Employment Size Category	Total Number of Firms	Financially Healthy Firms		Firms Likely to Fail	
		# of Firms	% of Firm Size Groups	# of Firms	% of Firm Size Groups
0-9 employees	174	162	93.1%	12	6.9%
10-49 employees	107	103	96.3%	4	3.7%
50-99 employees	40	40	100.0%	0	0.0%
100-500 employees	51	49	96.0%	2	4.0%
>500 employees	63	63	100.0%	0	0.0%
All small firms (Less than or equal to 500 employees)	372	354	95.2%	18	4.8%
All firms	435	417	95.9%	18	4.1%

Source: ERG estimates.

9.5 IMPACTS ON SMALL COASTAL OIL AND GAS FIRMS

As discussed above and in Section Six, impacts on net income from compliance costs could not be determined at most firms in the analysis because of the way in which wells were sampled in the Section 308 survey. Unless at least one discharging well was surveyed at a firm, the proportion of revenues from discharging wells could not be calculated and the loss of some or all of those revenues therefore could not be accounted for. Thus, two measures are used to determine whether disproportionate impacts are occurring among small firms: the firm failure analysis and a screening analysis of impacts measured as changes in equity and working capital. These analyses are discussed below.

9.5.1 Results of Screening and Firm Failure Analysis

In Section Six, the EIA examined firm-level impacts by screening firms to determine potential impacts on equity and working capital assuming that annual costs would be paid for either through increased liabilities or by using working capital. Where annual costs exceeded 5 percent of either equity or working capital, the potential for significant impacts was considered in more detail. The only firms in the sample considered in Section Six that were identified as concerns were small firms. Only six firms in the sample (representing 12 in the survey universe) were further identified as possible firm failures (although in all cases, these are not definite firm failures; information necessary to eliminate them from consideration as firm failures was lacking). Most of these failures are among firms in the 0-to-9 employees group (85 percent) (see Table 9-5). Out of the 354[1] small firms in the estimated postbaseline survey universe, however, the 12 possible firm failures represent only a maximum of 3.4 percent of small firms and only 2.9 percent of all Gulf of Mexico oil and gas firms.

It is important to note that most coastal oil and gas firms in the Gulf of Mexico (as of 1996) will not be discharging wastes. Only 29 percent of the coastal oil and gas firms are estimated to be discharging any produced water as of 1996. Thus, the typical small oil and gas firm (represented as the median firm) *is estimated to incur no compliance costs whatsoever.*

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[1]435 firms, minus 63 large firms, and minus 18 firm failures.

TABLE 9-5

POSTCOMPLIANCE FIRM FAILURES BY SIZE OF FIRM

Employment Size Category	Total Number of Firms	Financially Healthy Firms		Firms Likely to Fail	
		# of Firms	% of Firm Size Groups	# of Firms	% of Firm Size Groups
0-9 employees	162	152	93.8%	10	6.2%
10-49 employees	103	103	100.0%	0	0.0%
50-99 employees	40	40	100.0%	0	0.0%
100-500 employees	49	47	95.9%	2	4.1%
>500 employees	63	63	100.0%	0	0.0%
All small firms (Less than or equal to 500 employees)	354	342	96.6%	12	3.4%
All firms	417	405	97.1%	12	2.9%

Source: ERG estimates.

Moreover, compliance costs as a percentage of the present value of net income at the median small firm (as well as at the median large firm) in the coastal oil and gas industry will be zero, even if net income declines slightly over time. Additionally, the typical small coastal oil and gas firm will not be disproportionately affected by the proposed effluent guidelines as compared to the typical large coastal oil and gas firm.

9.6 REFERENCES

Dun & Bradstreet. 1993. Industry Norms 1992-1993.

SECTION TEN

IMPACTS ON NEW SOURCES

In most cases, the selected NSPS and PSNS regulations have been set equal to the selected BAT options. The only exception (among options with costs and impacts) is the produced water option as it affects Cook Inlet. Option #4, zero discharge with offshore limitations in Cook Inlet, is proposed for BAT, but NSPS for produced water would require zero discharge in all regions. For all other options with costs and impacts, BAT equals NSPS. For these other waste streams (and in the Gulf of Mexico for produced water, because new sources face the same requirements as existing sources and BAT has been found to be economically achievable), new treatment facilities should face no significant barriers to entry and NSPS requirements should be economically achievable as well.

Impacts on new sources in Cook Inlet from the NSPS requirements for produced water, however, should be addressed. Two NSPS economic models were run for Cook Inlet in the EIA for the Offshore Effluent Guidelines (U.S. EPA, 1993, Table 7-19; Table 7-21). These models include a 24-slot gas/oil platform and a 12-slot gas platform. The gas/oil platform was estimated to incur incremental compliance costs for produced water disposal under a zero-discharge requirement of $1.8 million annually (inflated to 1992 dollars). The key impacts affecting whether a new project would be undertaken (which would lead to conclusions about barriers to entry) include impacts on net present value (NPV) and impacts on the internal rate of return (IRR). The 24-slot gas/oil platform is projected to face declines in NPV of 2.9 percent from baseline under a zero-discharge requirement for produced water. IRR drops 5.1 percent; however, this drop is estimated to be from 39 percent in the baseline to 37 percent in the zero-discharge scenario. These impacts are not likely to affect the decision to undertake a project in Cook Inlet (given production levels similar to existing Cook Inlet platforms). Additionally, the impact on NPV from the zero-discharge requirement is not substantially different from the impacts on NPV from the BAT gas flotation requirement at existing Cook Inlet platforms. The decline in NPV projected for the BAT option is 2.4 percent. Thus, existing platforms and new

platforms will face similar impacts on NPV even though the NSPS requirement is more environmentally stringent than the BAT requirement.

Costs and impacts associated with the Cook Inlet 12-slot platform are much less than those associated with the 24-slot platform or with existing platforms under BAT (see U.S. EPA, 1993, Table 7-21).

Based on the analyses performed for the Offshore Effluent Guidelines (which continue to be relevant analyses for the Coastal Effluent Guidelines), EPA concludes that impacts on new sources in Cook Inlet are minimal and the NSPS requirements should not pose significant barriers to entry for two reasons: (1) declines in returns (measured as NPV and IRR) most likely will not affect the decision to undertake a new project (i.e., profitability will not be significantly affected), and (2) impacts on new sources from NSPS requirements are not substantially greater than those on existing sources from BAT requirements.

10.1 REFERENCES

U.S. Environmental Protection Agency. 1993. Economic Impact Analysis of Effluent Limitations Guidelines and Standards for the Offshore Subcategory of the Oil and Gas Industry.

APPENDIX A

ECONOMIC ASSUMPTIONS USED IN THE PRODUCTION LOSS MODEL

The economic and financial accounting assumptions used in the economic model are based upon common oil industry financing methods and procedures. Changes in tax computations due to the Tax Reform Act of 1986 (Public Law 99-514) are incorporated in the EPA model.

A.1 MODEL PARAMETERS

A.1.1 Corporate Income Tax Rate

It is assumed that the projects analyzed using the production loss model are incremental to the other activities of the company and therefore the net taxable income is marginally taxed at the U.S. corporate rate of 34 percent. This assumption implies that the company has at least $100,000 of other net income without this project. In addition, it is assumed that any net losses in the initial years of a project can be applied to the net income of other projects, so that an effective tax shield of 34 percent of the loss is realized. Therefore, the yearly net cash outflow is 100 percent minus 34 percent, or 66 percent of the year's loss. This is appropriate because of the customary size and level of activities of firms undertaking oil exploration and production. The basis for federal income is gross revenues minus royalty payments, severance taxes, depletion and depreciation allowances, and operating costs.

A.1.2 Severance Taxes

The Alaska severance tax structure consists of nominal rates that are then adjusted by a formula. The nominal tax rates on oil are 12.25 percent of gross revenues for the first 5 years of production and 15 percent thereafter. The formula is referred to as the Economic Limit Factor (ELF). This formula for oil was changed in 1989, and is:

$$ELF = 1 - \left(\frac{300}{PPW}\right)^{\left(\frac{150,000}{TP}\right)^{1.5333}}$$

where

PPW = Average daily oil production per well per field

TP = Average daily production in field.

The change introduced in 1989 is the addition of a "field factor," which shelters small fields from paying severance taxes. If a field produces less than 300 barrels per day (bpd) per well, the ELF reaches zero. To pay tax a new oil field would need 100 million barrels in reserves and would need to produce 50,000 bpd when it comes on line. Our contact at the Alaska Department of Revenue reported that fields in Cook Inlet have not paid oil severance taxes for several years.

In addition, there is a production tax surcharge of 5 cents per barrel. This levy was a response to the Valdez oil spill and is allocated to an environmental clean-up fund.

The economic model for the platforms in Cook Inlet that produce oil is thus calculated as a $0.05 per barrel levy only; neither the severance tax nor the ELF will be referenced.

The ELF for gas is different. The formula is:

$$ELF = 1 - \frac{PEL}{TP}$$

where

PEL = Monthly production at the economic limit

TP = Total monthly production.

Three thousand Mcf per day per well or 90,000 Mcf per month per well is used for the economic limit. Gas severance taxes are calculated as follows:

$$\text{Gas Severance Taxes} = \text{Gross Revenues} \times 10.00\% \times \text{ELF}$$

Unlike the oil severance ELF, the gas ELF is applied regardless of the value of the product, as long as it is positive (Logsdon, 1994).

A.1.3 Royalty Rates

Operators of oil- and gas-producing properties are usually required to pay royalties to the lessors or owners of the land based on the value of extracted production. This includes the federal government for OCS leases, state governments for leases located in state waters, and the state or private owners for leases on land. In many instances, the royalty rate is either a floating rate that varies from year to year or is based on a complex calculation keyed to the amount or mix of production. For the projects modeled, it is assumed that an average fixed rate based on the owning company's data is the best approximation of royalty payments. The value of the royalty payments for Cook Inlet, Alaska, platforms are derived from data supplied by the owners. The value of the royalty payments for Gulf of Mexico coastal wells were obtained through the Section 308 Survey. For wells that did not report the royalty rates, typical rates of 16.6 percent for oil and 16.9 percent for gas were substituted.

A.1.4 Depreciation

The Tax Reform Act of 1986 modifies the Accelerated Cost Recovery System (ACRS) for property placed in service after 31 December 1986. Under the new system, most oil and gas equipment will be classified as 7-year property. The recovery method for this class is the double declining balance (Snook and Magnuson, 1986). The schedule used to write off capitalized costs in the model is as follows:

Year 1	14.29% of costs
Year 2	24.49%
Year 3	17.49%

Year 4	12.49%
Year 5	8.93%
Year 6	8.92%
Year 7	4.46%

Year 1 in the above table is defined as the first year in which the equipment is placed in service. According to the relevant accounting principles, this is the first year in which the equipment produces oil or gas.

The value of the deduction for depreciation is reduced by inflation. To maintain the calculations on a constant-dollar basis, the value of the deduction is adjusted downwards in later years by the inflation rate.

A.1.5 Basis for Depreciation

The Tax Reform Act of 1986 repealed the Investment Tax Credit (Snook and Magnuson, 1986; Coopers and Lybrand, 1986). This means that the initial basis for depreciation is 100 percent of the total capitalized costs.

A.1.6 Oil Depletion Allowance

An oil depletion allowance is used by industry to recover leasehold expenses and geological and geophysical expenses incurred at the beginning of a new project. Since the production loss model commences during the productive phase of the model, all previous expenses, including leasehold costs, are considered sunk costs. In most cases, no oil depletion allowance is taken, causing the model to underestimate earnings, and in doing so, underestimate the productivity of the project. Changes from the baseline case to the regulated case are unaffected by this omission. The discussion below describes the two methods of depletion and indicates when the model estimates the depletion allowance taken.

The production loss model can calculate depletion on both a cost basis and a percentage basis. The value used in subsequent calculations is determined by a flag identifying whether the oil company is a major or an independent. (Majors use the cost basis while independents use either the cost basis or the percentage basis to calculate depletion.)

Cost depletion allows the producer to recover the leasehold cost over the producing lifetime of the well. The leasehold cost consists of the bonus bid and geological and geophysical costs.

A.1.6.1 Depletion—Cost Basis

Cost depletion is based on units of production and is represented by the following formula:

$$B = \frac{S}{U + S}$$

where:

B = adjusted basis of leased property
S = units sold during the period
U = units remaining at the end of the period.

The initial basis of the property used in the ERG model consists of the bonus bid and the geological and geophysical expenses. The basis is then adjusted downwards to account for the depletion taken in each period. The portion of the adjusted basis taken as depletion in any given period is the units sold during the period, divided by the units sold and the recoverable units remaining. For the purposes of the model, it is assumed that all units produced in a period are sold in the same period. Thus, the depletion for any given period is equal to the adjusted basis multiplied by the ratio of units produced in the period to the sum of the units produced and remaining. In this manner, the leasehold cost is amortized over the productive life of the well.

The value of the cost basis depletion is reduced in later years by inflation. The value in the annual cash flow is the inflation-adjusted value. The unadjusted value is used to calculate the basis for depletion in subsequent years.

A.1.6.2 Depletion—Percentage Basis

The rules for percentage depletion are found in Sections 613 and 613a of the tax code. When production is less than 1,000 barrels per day, depletion is calculated as follows:

$$\text{Depletion} = (\text{Gross Oil Revenues} - \text{Oil Royalties}) \times 0.15 \times (1 - \text{Royalty Rate})$$

When production exceeds 1,000 barrels per day, the following formula is used:

$$\text{Depletion} = (1000 \times \text{Wellhead Price per Barrel of Oil}) \times 0.15 \times (1 - \text{Royalty Rate})$$

That is, independents are allowed to take an allowance of 15 percent of the taxable revenues based on production up to and including 1,000 barrels of oil per day.

An analogous set of equations applies for the gas depletion allowance, except that the limit on the depletable quantity is 6,000 Mcf per day.

A.1.6.3 Application to the Model

In the production loss model, major producers have no leasehold costs to be depleted because the costs are considered sunk costs. All Cook Inlet operators and some Gulf of Mexico operators have $0 as the annual value for depletion. Independent producers, however, have oil depletion allowances calculated on a percentage basis, and therefore show depletion allowances in the income statements of the model.

A.1.7 Inflation Rate

The effective value of depreciation and cost-basis-depletion deductions is reduced by inflation since the expenditures occur in year(s) prior to the deduction. The model calculates an "adjusted depreciation" as follows:

$$\text{Adjusted depreciation in year X} = \frac{\text{Depreciation in year X}}{(1 + \text{inflation rate})^{\text{Year X}}}$$

An "adjusted cost-basis-depletion" is calculated in a similar manner.

The inflation rate of 3.0 percent for 1992 was obtained from Commerce (1993).

A.1.8 Discount Rate

For Gulf of Mexico operators, the nominal discount rate was company specific and was taken from the Section 308 survey. The nominal discount rate was decreased by the inflation factor (described in A.1.7) to obtain the real discount rate.

For respondents who were missing data, reported a nominal discount rate of less than 4 percent, or reported a rate higher than 20 percent, the survey average nominal discount rate of 10.85 percent was substituted. When respondents reported rates higher than 20 percent, the response was assumed to be the "hurdle rate," the minimum rate of return required for a company to undertake prospective projects.

A.2 REFERENCES

Commerce, 1993. Statistical Abstract of the United States 1993: The National Data Book, U.S. Department of Commerce, Bureau of the Census, 113th edition, Table No. 756, 1993.

Coopers and Lybrand. 1986. Tax Reform Act of 1986: Analysis, New York, NY.

Snook, S.B. and W.J. Magnuson, Jr. 1986. "The Tax Reform Act's Hidden Impact on Oil and Gas," The Tax Adviser, December, pp. 777-83.

Logsdon, C. 1994. Personal communication between Maureen F. Kaplan, Eastern Research Group, Inc., and Charles Logsdon, Alaska Department of Revenue, June 6.

Snook, S.B. and W.J. Magnuson, Jr. 1986. "The Tax Reform Act's Hidden Impact on Oil and Gas," The Tax Adviser, December, pp. 777-83.

APPENDIX B

EPA ECONOMIC MODEL FOR COASTAL PETROLEUM PRODUCTION IN COOK INLET, ALASKA

B.1 INTRODUCTION

The EPA model for Cook Inlet platforms simulates the costs and petroleum production dynamics expected in the production and development of a coastal platform for oil and/or gas. Data to define the platform and the petroleum reservoir are entered into the model. Through the use of internal algorithms, the model calculates the economic and engineering characteristics of the project. Outputs from the model include production volume, project economics, and summary statistics.

The model is structured to be flexible. It is capable of modeling projects that are dynamic, with development occurring over a 7-year drilling period and specific drilling planned during that period. Flexibility is possible through the use of user-specified inputs for a wide variety of variables. Inputs include, but are not limited to, drilling schedules, operating costs, initial petroleum production, production decline rates, tax rate schedules, and wellhead prices. The data define the production and development project.

From the user-specified data, costs and production performance are calculated on a yearly basis through a series of algorithms. The model calculates yearly production, present value of yearly production, and present value of production income. The model generates a consistent set of annual values and summary statistics to evaluate the project. All dollar amounts in this analysis and in the accompanying printout are in thousands of 1992 dollars.

B.1.1 Model Phases

The project life of a coastal platform producing oil and/or gas is divided into five phases: (1) from lease bid to the start of exploration, (2) from the start of exploration to the start of delineation, (3) from the start of delineation to the start of development, (4) from the start of development to the start of production, and (5) production. The Cook Inlet model evaluates projects that have completed the first four phases and are in the fifth phase.

For these multiple-well platform projects, the impetus to increase declining production is considerable if the platform can maintain profitability. Continued development may overlap the production phase; that is, some wells may be drilled while production continues at other wells on the platform. The EPA model is capable of modeling this situation.

The project operates for 30 years or for as long as it is profitable. Project economics are evaluated annually within the model algorithms and the project is shut down at the first negative cash flow.

B.1.2 Economic Overview of the Model

The economic characteristics of the model phases are quite different. Phases one through four generate cash outflows; no revenues are earned during this period. These costs are all considered sunk costs in the model since these projects are all operating. The fifth phase, production, generates net cash inflows. During this phase, the project continues to operate as long as operating cash inflows exceed cash expenses.

B.1.2.1 Cash Flows—Categorization

The model deals with a number of basic cash flows (or resource transfers) in the production phase and development phase. The basic cash flows are as follows:

Development Phase:	Well drilling costs—costs of drilling a recompletion or new production well.
	Incremental drilling costs—additional costs of drilling due to new or revised regulation concerning drilling fluids and drill cuttings.
Production Phase:	Revenues from oil and gas production—production levels multiplied by price forecasts.
	O&M costs—costs of operating and maintaining the well.
	Incremental O&M costs—additional cost due to new or revised regulations concerning produced water.
	Incremental capital costs—additional costs due to new equipment required for additional pollution control of produced water.

B.2 STEP-BY-STEP DESCRIPTION OF THE MODEL

This section provides a sequential overview of how the model operates, starting with the production phase and ending with the shut down of the well either after 30 years of production or when the project becomes unprofitable. To illustrate the code, the inputs, calculations, and outputs for a sample oil and gas platform in Cook Inlet, Alaska, are used, as presented in Figure B-1.

The discussion is based on the computer printout attached to this appendix. Identification numbers for specific lines are given in the left-hand margin. A list of user-specified inputs is given in Table B-1. All dollar values (e.g., costs and revenues) are expressed in thousands of 1992 dollars. Values on the spreadsheet may differ in the final digit from numbers presented in the text due to rounding.

Phases one through three (Leasing, Exploration, and Delineation) are not detailed here because they are considered to have already been completed prior to the base year of the model.

Line 1 is the real discount rate, i.e., the cost of capital. This value is used throughout the code to discount future cash inflows, cash outflows, and production in order to express them in present value terms.

FIGURE B-1

COOK INLET PRODUCTION LOSS MODEL

(1) Real Discount Rate:	8.00%
(2) Inflation Rate:	4.20%
(3) Percent Costs Expensed:	42.00%
(4) Drilling Mud Cost Increment ($000):	$0
(5) Corporate Tax Rate:	34%

CONSTRUCTION COSTS

(6) Total Platform Cost:	$0
(7) Pollution Control Capital Costs ($000):	$2,500
(8) Drilling Cost Per Well ($000):	$1,360 (Recompletion cost)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
(9) Drilling Cost Per Well:	$1,360	$1,360	$1,360	$1,360	$1,360	$1,360	$1,360	$1,360	$1,360	$1,360
(10) Number of Wells Drilled:	0	3	0	0	0	0	0	0	0	0
(11) Total Drilling Costs for Year:	$0	$4,080	$0	$0	$0	$0	$0	$0	$0	$0
(12) Annual Platform Cost:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(13) Annual Poll Cont Capital Costs:	$2,500	$0	$0	$0	$0	$0	$0	$0	$0	$0
(14) Total Annual Capital Cost:	$2,500	$4,080	$0	$0	$0	$0	$0	$0	$0	$0
(15) Tax Shield:	$357	$583	$0	$0	$0	$0	$0	$0	$0	$0
(16) Expensed Cash Flow:	$693	$1,131	$0	$0	$0	$0	$0	$0	$0	$0
(17) Capitalized Cash Flow:	$1,450	$2,366	$0	$0	$0	$0	$0	$0	$0	$0

(18) PV of All Construction Costs:	$5,813
(19) PV of Expensed Construction Costs:	$1,611
(20) PV of Capitalized Construction Costs:	$3,371

FINANCIAL RATES

(21) 1996 Oil Production (BPD)- Platform	2000							
(22) Oil/Gas Prod. Decline Rate/Year (%):	92%							
(23) Cost Escalator (%):	0%							
(24) Royalty Rate (%):	11.1%							
(25) Federal Tax Rate (%):	34%							
(26) Average Depreciation Life (years):	7							
(27) Deprec. rate (subsequent years):	14.29%	24.49%	17.49%	12.49%	8.93%	8.92%	8.93%	4.46%
(28) State Severance Tax Rate-Oil:	99							
(29) (If Alaska enter 99)								
(30) State Severance Tax Rate-Gas:	99							
(31) (If Alaska enter 99)								

PRODUCTION COSTS

(32) Gas Only? (1=yes, 0=no):	0
(33) Yrs Btwn Strt Dev & Strt Prod (<5):	0
(34) Number of Years at Peak Prod (=>1):	1
(35) Oil Peak Prod. Rate/Well(bb):	500
(36) Gas Peak Prod. Rate/Well(MMCF/D):	0

(37) Price of Oil Per Barrel:	$14.50
(38) Price of Gas Per MCF:	$1.57
(39) Total Operating Costs ($000):	$5,877
(40) Poll Cont Oper Costs ($000):	$200
(41) Regulatory cost for Recompletion ($000):	$85
(42) Days of Production Per Year:	365

	Year 1 1996	Year 2 1997	Year 3 1998	Year 4 1999	Year 5 2000	Year 6 2001	Year 7 2002	Year 8 2003	Year 9 2004	Year 10 2005
OIL AND GAS PRODUCTION										
(43) Producing Wells:	0	3	0	0	0	0	0			
(44) Barrels of Oil Per Day:	0	1500	1380	1270	1168	1075	2201	2025	1863	1714
(45) 1992 Oil Production	2000	1840	1693	1557	1433	1318				
(46) Days of Production Per Year:	365	365	365	365	365	365	365	365	365	365
(47) Barrels of Oil Per Year:	730000	1219100	1121572	1031846	949299	873355	803486	739207	680071	625665
(48) Price/Barrel of Oil:	$14.50	$14.50	$14.50	$14.50	$14.50	$14.50	$14.50	$14.50	$14.50	$14.50
(49) MMCF of Gas Per Day:	0	0	0	0	0	0	0	0	0	0
(50) MMCF of Gas Per Year:	0	0	0	0	0	0	0	0	0	0
(51) Price/MCF of Gas:	$1.57	$1.57	$1.57	$1.57	$1.57	$1.57	$1.57	$1.57	$1.57	$1.57
INCOME STATEMENT FOR YEARS 1 - 10										
(52) Annual Oil Revenues ($000):	$10,585	$17,677	$16,263	$14,962	$13,765	$12,664	$11,651	$10,719	$9,861	$9,072
(53) Annual Gas Revenues ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(54) Total Revenues ($000):	$10,585	$17,677	$16,263	$14,962	$13,765	$12,664	$11,651	$10,719	$9,861	$9,072
(55) Royalty Payments-Oil ($000):	$1,175	$1,962	$1,805	$1,661	$1,528	$1,406	$1,293	$1,190	$1,095	$1,007
(56) Royalty Payments-Gas ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(57) Severance Taxes-Oil ($000):	$37	$61	$56	$52	$47	$44	$40	$37	$34	$31
(58) Severance Taxes-Gas ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(59) ELF for Alaska Severance Taxes-Oil:	0.00	0.25	0.20	0.15	0.10	0.06	0.45	0.41	0.36	0.32
(60) ELF for Alaska Severance Taxes-Gas:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(61) Net Revenues ($000):	$9,374	$15,654	$14,402	$13,249	$12,189	$11,214	$10,317	$9,492	$8,732	$8,034
(62) Total Operating Costs ($000):	$5,877	$5,877	$5,877	$5,877	$5,877	$5,877	$5,877	$5,877	$5,877	$5,877
(63) Expensed Poll.Cont.Cap.Costs ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(64) Poll.Con.Operating Costs ($000):	$200	$454	$200	$200	$200	$200	$200	$200	$200	$200
(65) Capitalized Costs ($000):	$1,450	$2,366	$0	$0	$0	$0	$0	$0	$0	$0
(66) Adjstd Depreciation & Amort ($000):	$199	$639	$736	$505	$346	$266	$255	$199	$73	$0
(67) Operating Earnings ($000):	$3,297	$9,323	$8,325	$7,173	$6,113	$5,138	$4,241	$3,415	$2,656	$1,957
(68) Earnings Before Interest and ODA:	$3,098	$8,685	$7,589	$6,668	$5,767	$4,872	$3,985	$3,217	$2,583	$1,957
(69) Adjstd Depletion (Cost Basis):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(70) Surplus Depletion:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(71) Earnings Before Interest and Taxes:	$3,098	$8,685	$7,589	$6,668	$5,767	$4,872	$3,985	$3,217	$2,583	$1,957
(72) Statutory Tax:	$1,053	$2,953	$2,580	$2,267	$1,961	$1,656	$1,355	$1,094	$878	$666
(73) Earnings Before Interest After Tax:	$2,045	$5,732	$5,009	$4,401	$3,806	$3,215	$2,630	$2,123	$1,705	$1,292
(74) Net Cash Flow:	$2,244	$6,370	$5,745	$4,906	$4,152	$3,481	$2,886	$2,322	$1,778	$1,292
(75) Shutoff?	1	1	1	1	1	1	1	1	1	1
(76) Actual Oil Prod./Year (Barrels):	730000	1219100	1121572	1031846	949299	873355	803486	739207	680071	625665
(77) Actual Gas Prod./Year (MMCF):	0	0	0	0	0	0	0	0	0	0
(78) Actual Gross Revenues ($000):	$10,585	$17,677	$16,263	$14,962	$13,765	$12,664	$11,651	$10,719	$9,861	$9,072
(79) Actual Net Revenues ($000):	$9,374	$15,654	$14,402	$13,249	$12,189	$11,214	$10,317	$9,492	$8,732	$8,034
(80) Actual Net Cash Flow ($000):	$2,244	$6,370	$5,745	$4,906	$4,152	$3,481	$2,886	$2,322	$1,778	$1,292
(81) Actual Taxes Paid ($000):	$1,053	$2,953	$2,580	$2,267	$1,961	$1,656	$1,355	$1,094	$878	$666
(82) Capitalized Costs Not Expended:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(83) Surplus Depreciation:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
OIL AND GAS PRODUCTION										
(84) Barrels Oil Per Day:	1577	1451	1335	1228	1130	1039	956	880	809	745
(85) Days of Production Per Year:	365	365	365	365	365	365	365	365	365	365
(86) Barrels Oil Per Year:	575612	529563	487198	448222	412364	379375	349025	321103	295415	271782
(87) Price Per Barrel:	$14.50	$14.50	$14.50	$14.50	$14.50	$14.50	$14.50	$14.50	$14.50	$14.50
(88) MMCF Gas Per Day:	0	0	0	0	0	0	0	0	0	0
(89) MMCF Gas Per Year:	0	0	0	0	0	0	0	0	0	0
(90) Price Per MCF:	$1.57	$1.57	$1.57	$1.57	$1.57	$1.57	$1.57	$1.57	$1.57	$1.57
INCOME STATEMENT FOR YEARS 11 - 20										
(91) Oil Revenues ($000):	$8,346	$7,679	$7,064	$6,499	$5,979	$5,501	$5,061	$4,656	$4,284	$3,941
(92) Gas Revenues ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(93) Total Revenues ($000):	$8,346	$7,679	$7,064	$6,499	$5,979	$5,501	$5,061	$4,656	$4,284	$3,941
(94) Royalty Payments-Oil ($000):	$926	$852	$784	$721	$664	$611	$562	$517	$475	$437
(95) Royalty Payments-Gas ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(96) Severance Taxes-Oil ($000):	$29	$26	$24	$22	$21	$19	$17	$16	$15	$14
(97) Severance Taxes-Gas ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(98) ELF for Alaska Severance Taxes-Oil:	0.27	0.23	0.18	0.13	0.09	0.05	0.01	ERR	ERR	ERR
(99) ELF for Alaska Severance Taxes-Gas:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(100) Net Revenues($000):	$7,391	$6,800	$6,256	$5,755	$5,295	$4,871	$4,482	$4,123	$3,793	$3,490
(101) Operating Costs:	5876.5	5876.5	5876.5	5876.5	5876.5	5876.5	5876.5	5876.5	5876.5	5876.5
(102) Expensed Poll.Cont.Cap.Costs ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(103) Pollution Control Operating Costs:	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200
(104) For PV Poll. Control:	$200	$200	$200	$0	$0	$0	$0	$0	$0	$0
(105) Adjstd Depreciation & Amort ($000):	$0	$0	$0	$0	$0	$0	$0			
(106) Operating Earnings ($000):	$1,315	$723	$179	($321)	($782)	($1,205)	($1,595)	($1,953)	($2,283)	($2,587)
(107) Earnings Before Interest and ODA:	$1,315	$723	$179	($321)	($782)	($1,205)	($1,595)	($1,953)	($2,283)	($2,587)
(108) Adjsted Depletion (Cost Basis):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(109) Surplus Depletion:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(110) Earnings Before Interest and Taxes:	$1,315	$723	$179	($321)	($782)	($1,205)	($1,595)	($1,953)	($2,283)	($2,587)
(111) Statutory Tax:	$447	$246	$61	($109)	($266)	($410)	($542)	($664)	($776)	($879)
(112) Earnings Before Interest After Tax:	$868	$477	$118	($212)	($516)	($795)	($1,053)	($1,289)	($1,507)	($1,707)
(113) Net Cash Flow:	$868	$477	$118	($212)	($516)	($795)	($1,053)	($1,289)	($1,507)	($1,707)
(114) Shutoff?	1	1	1	0	0	0	0	0	0	0
(115) Actual Oil Prod./Year (Barrels):	575612	529563	487198	0	0	0	0	0	0	0
(116) Actual Gas Prod./Year (MMCF):	0	0	0	0	0	0	0	0	0	0
(117) Actual Gross Revenues ($000):	$8,346	$7,679	$7,064	$0	$0	$0	$0	$0	$0	$0
(118) Actual Net Revenues ($000):	$7,391	$6,800	$6,256	$0	$0	$0	$0	$0	$0	$0
(119) Actual Net Cash Flow ($000):	$868	$477	$118	$0	$0	$0	$0	$0	$0	$0
(120) Actual Taxes Paid ($000):	$447	$246	$61	$0	$0	$0	$0	$0	$0	$0
(121) Capitalized Costs Not Expended:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(122) Surplus Depreciation:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
OIL AND GAS PRODUCTION										
(123) Barrels Oil Per Day:	685	630	580	533	491	451	415	382	352	323
(124) Days of Production Per Year:	365	365	365	365	365	365	365	365	365	365
(125) Barrels Oil Per Year:	250039	230036	211633	194703	179126	164796	151613	139484	128325	118059
(126) Price Per Barrel:	$14.50	$14.50	$14.50	$14.50	$14.50	$14.50	$14.50	$14.50	$14.50	$14.50
(127) MMCF Gas Per Day:	0	0	0	0	0	0	0	0	0	0
(128) MMCF Gas Per Year:	0	0	0	0	0	0	0	0	0	0
(129) Price Per MCF:	$1.57	$1.57	$1.57	$1.57	$1.57	$1.57	$1.57	$1.57	$1.57	$1.57
INCOME STATEMENT FOR YEARS 21 - 30										
(130) Oil Revenues ($000):	$3,626	$3,336	$3,069	$2,823	$2,597	$2,390	$2,198	$2,023	$1,861	$1,712
(131) Gas Revenues ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(132) Total Revenues ($000):	$3,626	$3,336	$3,069	$2,823	$2,597	$2,390	$2,198	$2,023	$1,861	$1,712
(133) Royalty Payments-Oil ($000):	$402	$370	$341	$313	$288	$265	$244	$224	$207	$190
(134) Royalty Payments-Gas ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(135) Severance Taxes-Oil ($000):	$13	$12	$11	$10	$9	$8	$8	$7	$6	$6
(136) Severance Taxes-Gas ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(137) ELF for Alaska Severance Taxes-Oil:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(138) ELF for Alaska Severance Taxes-Gas:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(139) Net Revenues($000):	$3,211	$2,954	$2,717	$2,500	$2,300	$2,116	$1,947	$1,791	$1,648	$1,516
(140) Operating Costs:	5876.5	5876.5	5876.5	5876.5	5876.5	5876.5	5876.5	5876.5	5876.5	5876.5
(141) Pollution Control Operating Costs:	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200
(142) For PV Poll. Control:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(143) Operating Earnings ($000):	($2,866)	($3,123)	($3,359)	($3,576)	($3,776)	($3,960)	($4,130)	($4,285)	($4,429)	($4,561)
(144) Earnings Before Interest and ODA:	($2,866)	($3,123)	($3,359)	($3,576)	($3,776)	($3,960)	($4,130)	($4,285)	($4,429)	($4,561)
(145) Adjsted Depletion (Cost Basis):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(146) Surplus Depletion:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(147) Earnings Before Interest and Taxes:	($2,866)	($3,123)	($3,359)	($3,576)	($3,776)	($3,960)	($4,130)	($4,285)	($4,429)	($4,561)
(148) Statutory Tax:	($974)	($1,062)	($1,142)	($1,216)	($1,284)	($1,347)	($1,404)	($1,457)	($1,506)	($1,551)
(149) Earnings Before Interest After Tax:	($1,891)	($2,061)	($2,217)	($2,360)	($2,492)	($2,614)	($2,726)	($2,828)	($2,923)	($3,010)
(150) Net Cash Flow:	($1,891)	($2,061)	($2,217)	($2,360)	($2,492)	($2,614)	($2,726)	($2,828)	($2,923)	($3,010)
(151) Shutoff?	0	0	0	0	0	0	0	0	0	0
(152) Actual Oil Prod./Year (Barrels):	0	0	0	0	0	0	0	0	0	0
(153) Actual Gas Prod./Year (MMCF):	0	0	0	0	0	0	0	0	0	0
(154) Actual Gross Revenues ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(155) Actual Net Revenues ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(156) Actual Net Cash Flow ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(157) Actual Taxes Paid ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

MODEL OUTPUT

(158) PV of Net Revenues:	$86,042
(159) PV of Excess Depletion:	$0
(160) PV of Surplus Depreciation:	$0
(161) PV of Leasehold Cost:	$0
(162) PV Poll. Cont. Costs:	$4,113
(163) PV of Royalties - Oil ($000):	$10,785
(164) PV of Royalties - Gas ($000):	$0
(165) PV of Severance Taxes - Oil ($000):	$335
(166) PV of Severance Taxes - Gas ($000):	$0
(167) PV of Income Taxes Paid ($000):	$12,041
(168) PV of Operating Costs ($000):	$46,447
(169) Total Company Costs ($000):	$78,703
(170) Total Company Costs - Oil ($000):	$78,703
(171) Total Company Costs - Gas ($000):	$0
(172) Annualized Poll.Cont.Costs ($000):	$520
(173) PV Equiv. of Oil (bbl):	6,700,838
(174) PV Equiv. of Gas (MMCF):	0
(175) PV BOE	6,700,838
(176) Amortized Company Cost per bbl:	$11.75
(177) Amortized Company Cost per Mcf:	ERR
(178) Amortized Company Cost per BOE:	ERR
(179) PV of Social Costs - Total:	$54,058
(180) PV of Social Costs - Oil:	$54,058
(181) PV of Social Costs - Gas:	$0
(182) Amortized Social Cost per bbl:	$8.07
(183) Amortized Social Cost per Mcf:	ERR
(184) Amortized Social Cost per BOE:	$8.07
(185) Net Present Value of Project:	$20,774
(186) Internal Rate of Return:	0.813
(187) No. of Years of Production:	13

TABLE B-1

EXOGENOUS VARIABLES USED IN THE COOK INLET PRODUCTION LOSS MODEL

Line Number	Parameter
1	Real discount rate
2	Inflation rate
3	Percent of cost considered expensible intangible drilling costs
4	Pollution control capital costs (drilling wastes)
5	Federal corporate tax rate
7	Pollution control capital costs (produced water)
8	Drilling cost per well (recompletion or new production well)
10	Number of production wells drilled
21	1996 estimated oil and/or gas production
22	Oil and gas production decline rate
23	Cost escalator
24	Royalty rate
27	Depreciation schedule
28	Severance tax rate—oil
30	Severance tax rate—gas
32	Gas-only flag
34	Years at peak production
35	Oil—peak production rate (bbl/day)
36	Gas—peak production rate (MMcf/day)
37	Wellhead price per barrel—oil
38	Wellhead price per Mcf—gas
39	Total operating costs
40	Annual pollution control equipment operating cost (produced water)
41	Pollution control operating cost (drilling wastes)

Source: EPA estimate.

Line 2 is the inflation rate. This parameter is used to reduce the value of the deductions for cost-basis depletion and depreciation in future years.

The petroleum industry has considerable latitude in its treatment of costs. An oil company can expense, in the period incurred, costs that would normally be capitalized. This immediate expensing of a portion of capital costs provides a significant tax advantage.

Line 3 contains the percentage of drilling costs that are considered "Intangible Drilling Costs" (IDCs) and are eligible for expensing. An initial value of 60 percent is used in this analysis as the percentage of costs considered IDCs. This is based on an estimated average percentage from data in Commerce, 1982; Commerce, 1983; and API, 1986. Under the Tax Reform Act of 1986, independents may expense 100 percent of IDCs, while majors may expense only 70 percent. Since the project is assumed to be a venture by a major company, the value shown is 42 percent (0.60 x 0.70).

The additional costs due to new pollution control regulations on drilling muds and cuttings are entered in line 4. The federal corporate income tax rate is entered on line 5.

B.2.1 Development Phase

The costs of production equipment and other infrastructure costs are entered in line 6. The value is 0 because these costs have already been incurred and are considered sunk costs. Additional construction costs for the installation of pollution control equipment are entered separately in line 7. The capital costs are incurred in year 1. Line 8 shows the cost to drill the type of well (new or recompletion) specified in the drilling schedule. The drilling cost for a well depends on the depth drilled, environmental requirements, and regional costs for parts and labor.

The development phase in the code is structured to accommodate the drilling of production wells according to the drilling schedules provided by the operator. Separate entries for the drilling cost per well and the number of wells drilled each year appear in lines 9 and 10.

Lines 11 through 13 calculate the costs incurred each year from the drilling of production wells, and the construction of production and pollution control facilities. The total annual capital development costs are given in line 14.

The tax shield, line 15, is the product of the annual total capital development costs, the corporate tax rate, and the percentage of costs expensed. For year 1 of the Cook Inlet model project, this is $2,500 x 0.34 x 0.42 or $357. The expensed cash flow, line 16, is the total annual capital development costs (line 14) times the percentage of costs expensed (line 3) minus the tax shield (line 15). For year 2, this is ($4,080 x 0.42) - $583 or $1,131. The capitalized cash flow, line 17, is the product of total capital costs and (1 - the percentage of expensible IDCs). For year 2, this is $4,080 x 0.58 or $2,366. Note that the sum of the tax shield, the expensed costs, and the capitalized costs is equal to the total costs.

Development costs are discounted to determine their present value in the base year. Present values of all development costs, expensed development costs, and capitalized development costs are given in lines 18 through 20, respectively.

B.2.2 Production Phase

In the production phase of the project, a variety of financial and engineering variables interact to form the economic history of the well. Line 22 provides the production decline rate for oil and gas. The EPA model incorporates an exponential function for production decline, i.e., a constant proportion of the remaining reserves is produced each year. For every barrel produced in the initial year of operation in this project, 0.92 barrel is produced in the second year, $(0.92)^2$ or 0.846 barrel in the third year, and so forth.

The EPA model is capable of handling cost escalation (see line 23). In this report, we are considering costs in real terms, and thus no escalation is assumed.

The royalty rate paid to the lessor of the land is provided in line 24. The depreciation schedule is listed in line 27. State severance taxes on oil and gas are given in lines 28 and 30,

respectively. Note the flag for calculating severance taxes for Alaska, since these must be adjusted by the Economic Limit Factor (ELF). These severance taxes are taken care of in the model years in lines 59 and 60; see previous discussion of the ELF in Appendix A.

Line 32 is a flag to identify gas-only projects. The flag is necessary for the proper calculation of depletion on a cost basis within the code.

The number of years that a well produces at its peak rate is given in line 34. The peak production rates per well for oil and gas are given in lines 35 and 36, respectively, and apply to wells brought on line in the model years. Initial production rates estimated as shown in Section Five are the peak production rates for the platforms in the model that do not drill. Note that these are figures for daily production and that the units for gas production are MMcf/day.

The wellhead prices for oil and gas are entered on lines 37 and 38, respectively. Annual operating costs are entered on line 39, while line 40 contains the incremental costs of water disposal due to compliance with pollution control regulations.

Line 41 is the regulatory cost associated with disposing of drilling wastes. For some platforms, this value is the cost of disposing of drilling fluids for a recompletion, while other platforms have costs to dispose of drilling fluids for new production wells.

Line 42 indicates the number of days per year that a well produces. In the production loss model, it is assumed that platforms operate continuously.

Line 43 provides the number of producing wells brought into service. The barrels of oil produced per day (line 44) is a function of the number of wells and the year in which they went into service. The 1992 oil production numbers in line 45 are the estimated production declined from 1992 figures of wells in production at the platform. These numbers together, multiplied by the number of days of production per year (line 46. repeated from line 42), provide barrels of oil per year (line 47).

In general, production for a group of wells that went into service in the same year is calculated as:

$$\text{Annual Production} = \begin{matrix}\text{Number}\\ \text{of Wells}\end{matrix} \times \begin{matrix}\text{Barrels}\\ \text{per day}\\ \text{per well}\end{matrix} \times \text{Decline rate}^{a} \times \begin{matrix}\text{Number}\\ \text{of days}\end{matrix}$$

where a = year of production − number of years at peak production.

This is extended to calculate production for wells going into service in different years. For example:

$$\begin{aligned}\text{Daily Production Year 2} &= 3 \text{ wells} \times 500 \text{ bopd}\\ &= 1{,}500 \text{ bopd}\\ \text{Year 3} &= (3 \times 500 \times 0.92)\end{aligned}$$

If additional wells were drilled in year 4,

$$\begin{aligned}\text{Year 4} &= (3 \times 500 \times 0.92^2) + (3 \times 500)\\ &= 1{,}270 + 1{,}500 \text{ bopd}\\ &= 1{,}770 \text{ bopd}\end{aligned}$$

and so forth.

The price per barrel is repeated in line 48 for convenience in cross-checking the gross revenues for oil production (line 52). Lines 49, 50, and 51 list the daily gas production, annual gas production, and wellhead price per Mcf.

B.2.2.1 Income Statement

Lines 52 through 74 compose an income statement that is repeated annually for a 30-year project lifetime. Since most projects become uneconomical before this, lines 75 through 81 check for a negative net cash flow and readjust the actual production, revenues, and cash flows to zero when appropriate.

Lines 52 and 53 list the revenues from oil and gas production. Total cash inflow for the year is given in line 54. Royalty payments (lines 55 and 56; see line 24 for the royalty rate) are calculated on the basis of gross revenues. Severance taxes are calculated on the basis of gross revenues minus royalty payments (lines 57 and 58; see lines 28 and 30 for severance tax rates). The ELF for the calculation of severance taxes for Alaska is taken into account in lines 59 and 60 (see Appendix A for a more complete discussion of severance tax calculations for Alaska). Net revenues for year 2, line 61, are calculated as:

$$\begin{aligned}\text{Net Revenues} &= \text{Total Gross Revenues} - \text{Royalty Payments} - \text{Severance Taxes}\\ &= \$17{,}677 - \$1{,}962 - \$0 - \$61 - \$0\\ &= \$15{,}654\end{aligned}$$

Operating costs are given in line 62; incremental operating costs due to pollution control appear in line 64. The entry on line 65 is the sum of the capitalized costs spent in the drilling phase including drilling waste disposal capital costs.

The adjusted depreciation allowance is listed in line 66. The depreciation schedule under the Tax Reform Act of 1986 is found on line 27. For example, in model year 1, the unadjusted depreciation allowance is the product of $1,450 (capitalized costs) and the depreciation rate for the appropriate year, e.g., $1,450 x 14.29% = $207 for the first year of operation for the project (year 1).

The figure of $207 would be used in the tax calculations for the company. The value of that deduction, however, has been eroded by inflation. To adjust for this effect, we calculate a

deduction that is deflated, e.g., $207 ÷ (1 + inflation rate)$^{Year\ X}$ or $207 ÷ $(1.042)^1$ = $198; see line 66 and note rounding.

In model year 2, the adjusted depreciation allowance contains second-year effects from the model year 1 capital costs and first-year effects of the model year 2 capital costs:

$$\text{Adjusted Depreciation Allowance} = \frac{(\$1{,}450 \times 24.49\%) + (\$2{,}366 \times 14.29\%)}{(1 + 0.042)^2}$$

$$= \$638 \text{ (note rounding)}$$

The operating earnings (line 67) are defined as net revenues (line 61) minus operating costs (line 62) minus pollution control operating costs (line 64). For year 2 of the project:

$$\text{Operating Earnings} = \text{Net revenues} - \text{Operating costs} - \text{Pollution control operating costs}$$

$$= \$15{,}654 - \$5{,}877 - \$454 = \$9{,}323$$

Line 68, earnings before interest and oil depletion allowance (ODA), subtracts depreciation and amortization from operating earnings. For year 2,

$$\text{Earnings Before Interest and ODA} = \$9{,}232 - \$639 = \$8{,}684$$

For major producers, the depletion allowance is calculated on a cost basis. For the years shown in the model, there is no depletion allowance because the model does not account for sunk leasehold costs. Appendix A contains more information on the oil depletion allowance.

Depletion is calculated based on oil production only, unless the gas-only flag is set in line 32. The depletion allowance is calculated on an unadjusted basis for every year and then deflated. If the project ends while a depletion allowance may still be taken, the depletion allowance in that year and subsequent years is termed "surplus depletion" (line 70).

Earnings before interest and taxes (line 71) is defined as the earnings before interest and ODA (line 68) minus the adjusted oil depletion allowance (line 69).

The earnings in line 71 form the basis for federal income tax. This is calculated in line 72 using the information in line 5 (federal corporate tax rate). Earnings after taxes are given in line 73.

The project cash flows, line 74, are determined by adding non-cash expenses, depreciation, and depletion to earnings after taxes. The net cash flow for year 2 is $5,732 + $639 + $0 = $6,370 (note rounding).

The cash flows forecasted for the project may or may not be sufficient to justify continuation of operations. In some circumstances, net cash flows may be positive only because of large values for depreciation, e.g., where large capital expenditures are required on a small project or later in the operating life of the project. Under these circumstances, the project is likely to shut down even though cash flow is positive. Project shutdown is evaluated by the parameter:

$$\text{Project Shutdown} = \text{Net cash flow (line 74)} - \left(\begin{matrix}\text{tax rate}\\ \text{(line 5)}\end{matrix} \times \begin{matrix}\text{depreciation and amortization}\\ \text{(line 66)}\end{matrix}\right) - (1 - \text{tax rate}) \times \left(\begin{matrix}\text{expensed pollution control capital costs}\\ \text{(line 63)}\end{matrix}\right)$$

which calculates the actual cash outlay in that year. If the parameter is equal to or less than zero, the project is assumed to shut down. The model prints a "1" in line 75 for years in which the project operates and a "0" for years in which the project does not operate.

In the event that the project is shut down, certain variables must be recalculated to reflect that decision. Lines 76 through 81 restate production volumes, revenues, and cash flow in light of the shutdown; that is, production and revenues are set to zero after the project shuts down. Other project variables, such as depreciation, are recalculated because of the earlier

shutdown date. Unexpended capitalized costs and surplus depreciation are given in lines 82 and 83.

The income statement for the second and third decades of operation are found on lines 91 through 113 and 130 through 150, respectively.

B.2.3 Summary Statistics

At the end of the project, all costs and revenues are put in present value terms as of the base year; see lines 158 through 187.

The present value of total company costs is the summation of the present values of the parameters so listed in Table B-2; see line 169. This parameter provides a measure of the present value of net company resources expended in development and operation of petroleum projects. Entries marked with a "plus" in the column contribute to corporate costs. Excess depreciation and surplus depletion lower corporate costs and are therefore marked with a "minus."

Total company costs for oil are the present values for oil royalties and severance taxes and the oil portion of the remaining costs (see line 170). These costs are apportioned by the ratio of oil revenues to total revenues. An analogous procedure is followed to obtain the total company cost for gas (see line 171).

The capital and the annual operation and maintenance costs for incremental pollution control of produced water effluents and drilling wastes are given in terms of present value and are annualized over the economic lifetime of the platform. The annualized cost is given in line 172.

Oil and gas production is also discounted to give a present value equivalent (see lines 173 through 175). Corporate costs per barrel and corporate costs per Mcf are obtained by dividing

TABLE B-2

COST AND CASH FLOW USES IN THE COOK INLET PRODUCTION LOSS MODEL

Cost or Cash Flow Item	Company Cost	Social Cost	Depre-ciation
Total capitalized development costs			+
PV of expensed investment cash flows	+		
PV of capitalized costs	+		
PV of pollution control costs - operations	+	+	
PV of pollution control costs - capital	+		+
PV of royalties	+		
PV of severance taxes	+		
PV of operating costs	+	+	
PV of income taxes	+		
PV of excess depletion	—		
PV of surplus deprecation	—		
PV of all investment costs		+	

PV = present value.

the present value of the company cost by the present value equivalent of production (see lines 176 through 178).

The present value of social costs (lines 179 through 181) provides a measure of the value of net social resources expended in the development and operation of coastal petroleum projects. The difference between company cost and social cost is that the social cost ignores the effects of transfers that do not use social resources. The items included in social cost are listed in Table B-2. Social cost per unit of production is obtained by dividing the social cost by the present value equivalent of production (lines 182 through 184).

The net present value of the project, line 185, is calculated as:

Net Present Value = PV of Cash Inflows - PV of Cash Outflows

= PV of Operating Cash Flows
- PV of Expensed Investment Cash Flows
- PV of Capitalized Costs
- PV of Leasehold Costs
+ PV of Excess Depletion
+ PV of Surplus Depreciation

A positive net present value is indicative of a profitable project at the assumed discount rate, i.e., it generates more revenue than investing the capital in a project with that expected rate of return.

The internal rate of return (line 186) equates the present value of capital in the exploration and development of the project with the present value of the operating cash flows. An internal rate of return higher than the discount rate is indicative of a profitable project.

The net present value and the internal rate of return are inverse methods of evaluating the profitability of a project. In calculating the net present value, the discount rate is fixed and the net present value may vary. In calculating the internal rate of return, the net present value is set to zero and the discount rate is allowed to fluctuate.

The number of years that the project operates is shown in line 187. This number reflects the total number of years that the project operates with a positive cash flow.

B.3 REFERENCES

API. 1986. 1984 Survey on Oil and Gas Expenditures, American Petroleum Institute, Washington, DC, October.

Commerce. 1982. Annual Survey of Oil and Gas, 1980, U.S. Department of Commerce, Bureau of the Census, Current Industrial Reports, MA-13k(80)-1, March.

Commerce. 1983. Annual Survey of Oil and Gas, 1981, U.S. Department of Commerce, Bureau of the Census, Current Industrial Reports, MA-13k(81)-1, March.

APPENDIX C

GULF OF MEXICO PRODUCTION LOSS MODEL

C.1 INTRODUCTION

This appendix describes in greater detail the production loss model used to estimate impacts to coastal region operations in the Gulf of Mexico. The model described below operates on the same principles as the model described in Appendix B, and therefore some sections refer to Appendix B for more information.

The production loss model simulates the costs and petroleum production dynamics expected in the production of a coastal well in the Gulf of Mexico. Data to define the well are entered into the model. Through the use of internal algorithms, the model calculates the economic and engineering characteristics of the well. Outputs from the model include: production volume, project economics, and summary statistics.

The model is structured to be flexible and is capable of using user-specified inputs for a wide variety of variables. Inputs include, but are not limited to, operating costs, initial petroleum production, production decline rates, tax rate schedules, and wellhead prices.

From the user-specified data, costs and production performance are calculated on an annual basis through a series of algorithms. The model generates a consistent set of annual values and summary statistics to evaluate the well. All dollar values in this analysis are presented in thousands of 1992 dollars.

C.1.1 Model Phases

The project life of the Gulf wells analyzed in the production loss model are currently-producing wells that discharge produced water. Since these wells are evaluated as individual

entities, the wells have completed the first four phases of a project's life as described in Section B.1.1. The projected future of the well is only analyzed in the fifth phase—the production phase.

The wells in this analysis produce to treatment facilities that may accept produced water and petroleum from more than one well. The lifetime of the treatment facility is not dependent on the individual well in this analysis since additional wells may be producing to the facility or new wells may be drilled and be served by the treatment facility. Therefore, any well closures estimated using the production loss model do not necessarily reflect the fate of the treatment facility.

C.1.2 Economic Overview of the Model

During the production phase of the well, there are a number of cash flows to consider. There are revenue flows from oil and gas production, operation and maintenance costs for operating the well and disposing of produced water, and incremental costs (both capital and O&M) that stem from new or revised regulations concerning produced water.

C.1.2.1 Produced Water Assumptions

For projects that produce oil or oil with gas, water production is calculated as a function of total liquid production. In other words, the well is assumed to produce a constant volume of fluid during its lifetime, but the proportion of fluid that is water will increase as the well ages. To evaluate water production as a function of total liquid production, we need to estimates several parameters:

- Relationship of oil decline and water increase
- Decline rate of oil production
- Watercut (i.e., percentage of water in the produced fluid)

Oil production is assumed to decline at an exponential rate. This is discussed in Appendix B. As oil production declines, water production increases, maintaining a constant volume of fluid. Figure C-1 illustrates the oil and water production relationship over time. Watercut data are available by calculating the ratio of daily water production to daily water and oil production from the Section 308 survey data.

Since incremental regulatory costs are determined on a per-barrel of produced water basis, the annual costs for produced water disposal increase annually.

C.2 STEP-BY-STEP DESCRIPTION OF THE MODEL

The ensuing discussion is a sequential overview of how the production loss model for the Gulf of Mexico coastal wells operates. The model begins in the production phase and ends with the shut-down of the well either after 30 years or when the well becomes unprofitable to operate. To illustrate the code, the inputs, calculations, and outputs, for a sample oil- and gas-producing well in the Gulf are used.

The discussion is based on the computer printout attached to the end of this appendix, labeled Figure C-2. Identification numbers for specific lines are given in the left-hand margin. A list of user-specified inputs is given in Table C-1. All dollar values are expressed in thousands of 1992 dollars, except for per-barrel costs as indicated, which are expressed in 1992 dollars. Values on the spreadsheet may differ in the final digit from numbers presented in the text because of rounding.

C.2.1 General Model Data

Line 2 is the real discount rate, i.e., the cost of capital. This value is specific to the well and is determined from the owner company-supplied financial data. The value supplied in the survey is the nominal interest rate, and the inflation rate presented in line 3 is subtracted to arrive at the real discount rate presented in line 4. If the user supplied a discount rate that

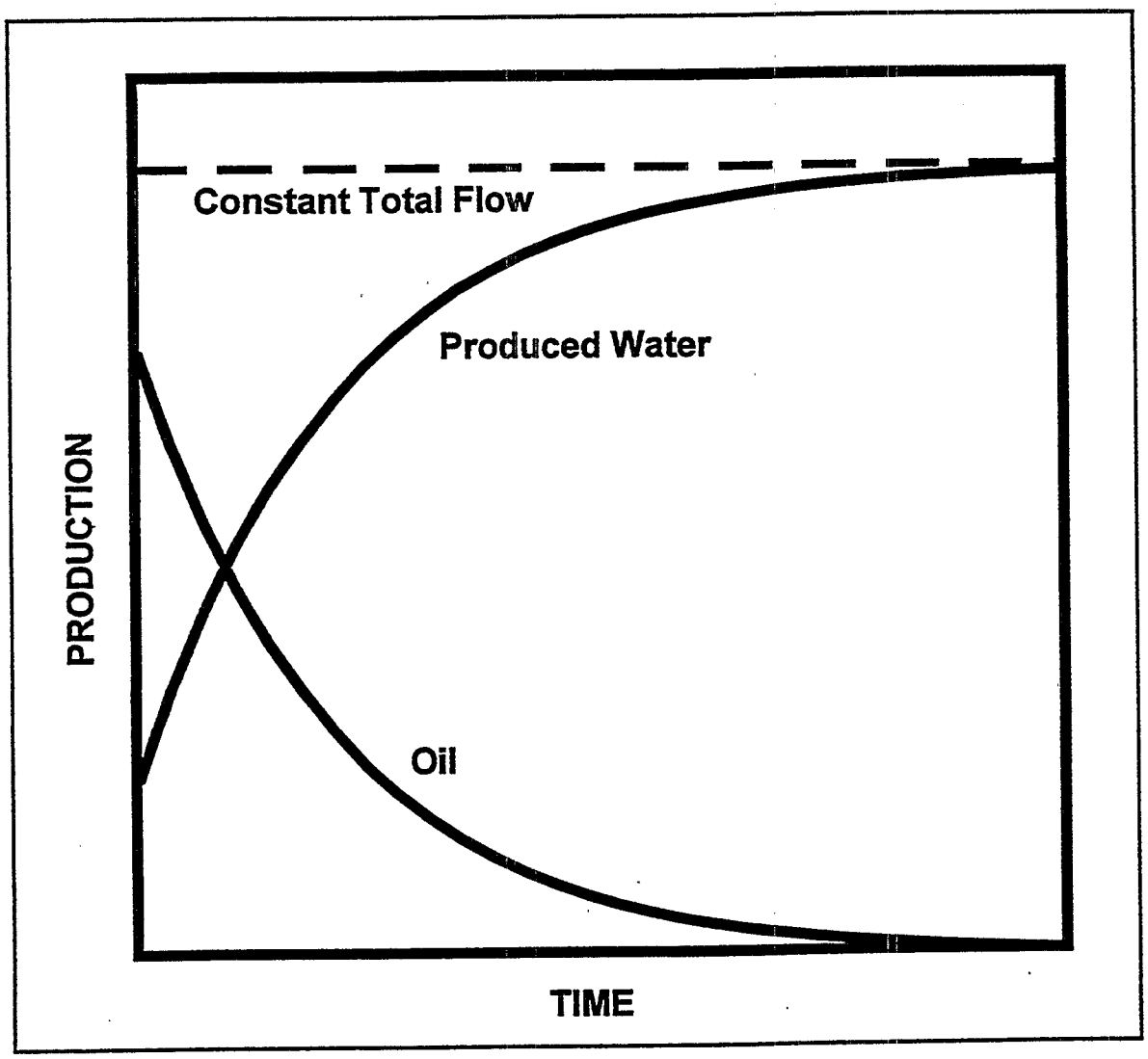

Figure C-1. Oil:Water relationship over time (exponential decline).

FIGURE C-2

GULF OF MEXICO PRODUCTION LOSS MODEL

GENERAL MODEL DATA

(1) Project Type:	Model Project	
(2) Real Discount Rate:	9.00%	Survey data
(3) Inflation Rate:	3.00%	Statistical Abstract 1993
(4) Corporate Tax Rate:	34%	
(5) State Corporate Tax Rate:	8.00%	
(6) Corp Structure (1-major/2-indep):	1	Survey data

FINANCIAL DATA

(7) Water:oil (bbl:bbl) or Water:gas (bbl:MMcf)	0.60	Survey data						
(8) Oil/Gas Prod. Decline Rate/Year (%):	85%							
(9) Cost Escalator (%):	0.00%							
(10) Royalty Rate (%):	16.67%	Survey data						
(11) Average Depreciation Life (years):	7							
(12) Deprec. schedule (rate per year):	14.29%	24.49%	17.49%	12.49%	8.93%	8.92%	8.93%	4.46%
(13) State Severance Tax Rate-Oil:	12.50%							
(14) State Severance Tax Rate-Gas:	4.05%							

PRODUCTION DATA

(15) Gas Only? (1=yes, 0=no):	0	Survey data
(16) Yrs Btwn Strt Dev & Strt Prod (<5):	1	
(17) Number of Years at Peak Prod:	1	
(18) Oil Peak Prod. Rate/Well(bbl/day):	250	Survey data
(19) Gas Peak Prod. Rate/Well(MMcf/day):	0.1	Survey data
(20) Number of Producing Wells:	1	
(21) Number of Wells Put in Service/Year:	1	
(22) Price of Oil Per Barrel:	$18.00	Survey data
(23) Price of Gas Per Mcf:	$1.50	Survey data
(24) Total Operating Costs per Well ($000):	$40	Survey data
(25) Pollution Control Equip. Operating Cost per bbl ($):	$0.35	Set to $0.00 for baseline scenario
(26) Days of Production Per Year:	365	

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
OIL, WATER, AND GAS PRODUCTION										
(27) Barrels of Oil Per Day:	250	213	181	154	131	111	94	80	68	58
(28) Days of Production Per Year:	365	365	365	365	365	365	365	365	365	365
(29) Barrels of Oil Per Year:	91250	77563	65928	56039	47633	40488	34415	29253	24865	21135
(30) Price/Barrel of Oil:	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00
(31) Barrels of Water Per Day:	150	188	219	246	269	289	306	320	332	342
(32) Total Fluid Per Day:	400	400	400	400	400	400	400	400	400	400
(33) MMCF of Gas Per Day:	0	0	0	0	0	0	0	0	0	0
(34) MMCF of Gas Per Year:	37	31	26	22	19	16	14	12	10	8
(35) Price/MCF of Gas:	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50
INCOME STATEMENT FOR YEARS 1 - 10										
(36) Annual Oil Revenues ($000):	$1,643	$1,396	$1,187	$1,009	$857	$729	$619	$527	$448	$380
(37) Annual Gas Revenues ($000):	$55	$47	$40	$34	$29	$24	$21	$18	$15	$13
(38) Total Revenues ($000):	$1,697	$1,443	$1,226	$1,042	$886	$753	$640	$544	$462	$393
(39) Royalty Payments-Oil ($000):	$274	$233	$198	$168	$143	$121	$103	$88	$75	$63
(40) Royalty Payments-Gas ($000):	$9	$8	$7	$6	$5	$4	$3	$3	$2	$2
(41) Severance Taxes-Oil ($000):	$205	$175	$148	$126	$107	$91	$77	$66	$56	$48
(42) Severance Taxes-Gas ($000):	$2	$2	$2	$1	$1	$1	$1	$1	$1	$1
(43) Net Revenues ($000):	$1,207	$1,026	$872	$741	$630	$535	$455	$387	$329	$280
(44) Total Operating Costs ($000):	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40
(45) Poll.Con.Operating Costs ($000):	$19	$24	$28	$31	$34	$37	$39	$41	$42	$44
(46) Operating Earnings ($000):	$1,148	$962	$804	$670	$556	$459	$376	$306	$246	$196
(47) Earnings Before Interest and ODA:	$1,148	$962	$804	$670	$556	$459	$376	$306	$246	$196
(48) Adjsted Depletion Allowance:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(49) Surplus Depletion:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(50) Earnings Before Interest and Taxes:	$1,148	$962	$804	$670	$556	$459	$376	$306	$246	$196
(51) Federal Tax (Earnings-State taxes):	$359	$301	$251	$209	$174	$143	$118	$96	$77	$61
(52) State Tax:	$92	$77	$64	$54	$44	$37	$30	$24	$20	$16
(53) Earnings Before Interest After Tax:	$697	$584	$488	$407	$337	$278	$228	$186	$150	$135
(54) Net Cash Flow:	$697	$584	$488	$407	$337	$278	$228	$186	$150	$135
(55) Shutoff?	1	1	1	1	1	1	1	1	1	1
(56) Actual Oil Prod./Year (Barrels):	91250	77563	65928	56039	47633	40488	34415	29253	24865	21135
(57) Actual Gas Prod./Year (MMCF):	37	31	26	22	19	16	14	12	10	8
(58) Actual Gross Revenues ($000):	$1,697	$1,443	$1,226	$1,042	$886	$753	$640	$544	$462	$393
(59) Actual Net Revenues ($000):	$1,207	$1,026	$872	$741	$630	$535	$455	$387	$329	$280
(60) Actual Net Cash Flow ($000):	$697	$584	$488	$407	$337	$278	$228	$186	$150	$135
(61) Actual Taxes Paid ($000):	$451	$378	$316	$263	$218	$180	$148	$120	$97	$77
(62) Capitalized Costs Not Expended:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(63) Surplus Depreciation:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
OIL, WATER, AND GAS PRODUCTION										
(64) Barrels Oil Per Day:	49	42	36	30	26	22	19	16	13	11
(65) Days of Production Per Year:	365	365	365	365	365	365	365	365	365	365
(66) Barrels Oil Per Year:	17965	15270	12980	11033	9378	7971	6775	5759	4895	4161
(67) Price Per Barrel:	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00
(68) Barrels of Water Per Day:	351	358	364	370	374	378	381	384	387	389
(69) Total Fluid Per Day:	400	400	400	400	400	400	400	400	400	400
(70) MMCF Gas Per Day:	0	0	0	0	0	0	0	0	0	0
(71) MMCF Gas Per Year:	7	6	5	4	4	3	3	2	2	2
(72) Price Per MCF:	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50
INCOME STATEMENT FOR YEARS 11 - 20										
(73) Oil Revenues ($000):	$323	$275	$234	$199	$169	$143	$122	$104	$88	$75
(74) Gas Revenues ($000):	$11	$9	$8	$7	$6	$5	$4	$3	$3	$2
(75) Total Revenues ($000):	$334	$284	$241	$205	$174	$148	$126	$107	$91	$77
(76) Royalty Payments-Oil ($000):	$54	$46	$39	$33	$28	$24	$20	$17	$15	$12
(77) Royalty Payments-Gas ($000):	$2	$2	$1	$1	$1	$1	$1	$1	$0	$0
(78) Severance Taxes-Oil ($000):	$40	$34	$29	$25	$21	$18	$15	$13	$11	$9
(79) Severance Taxes-Gas ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(80) Net Revenues($000):	$238	$202	$172	$146	$124	$105	$90	$76	$65	$55
(81) Operating Costs:	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40
(82) Pollution Control Operating Costs:	$45	$46	$47	$47	$48	$48	$49	$49	$49	$50
(83) Operating Earnings ($000):	$153	$116	$85	$59	$36	$17	$1	($13)	($25)	($35)
(84) Earnings Before Interest and ODA:	$153	$116	$85	$59	$36	$17	$1	($13)	($25)	($35)
(85) Adjsted Depletion Allowance:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(86) Surplus Depletion:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(87) Earnings Before Interest and Taxes:	$153	$116	$85	$59	$36	$17	$1	($13)	($25)	($35)
(88) Federal Tax (Earnings-State taxes):	$48	$36	$27	$18	$11	$5	$0	($4)	($8)	($11)
(89) State Tax:	$12	$9	$7	$5	$3	$1	$0	($1)	($2)	($3)
(90) Earnings Before Interest After Tax:	$93	$71	$52	$36	$22	$10	$1	($8)	($15)	($24)
(91) Net Cash Flow:	$93	$71	$52	$36	$22	$10	$1	($8)	($15)	($24)
(92) Shutoff?	1	1	1	1	1	1	1	0	0	0
(93) Actual Oil Prod./Year (Barrels):	17965	15270	12980	11033	9378	7971	6775	0	0	0
(94) Actual Gas Prod./Year (MMCF):	7	6	5	4	4	3	3	0	0	0
(95) Actual Gross Revenues ($000):	$334	$284	$241	$205	$174	$148	$126	$0	$0	$0
(96) Actual Net Revenues ($000):	$238	$202	$172	$146	$124	$105	$90	$0	$0	$0
(97) Actual Net Cash Flow ($000):	$93	$71	$52	$36	$22	$10	$1	$0	$0	$0
(98) Actual Taxes Paid ($000):	$60	$46	$33	$23	$14	$7	$0	$0	$0	$0
(99) Capitalized Costs Not Expended:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(100) Surplus Depreciation:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
OIL, WATER, AND GAS PRODUCTION										
(101) Barrels Oil Per Day:	10	8	7	6	5	4	4	3	3	2
(102) Days of Production Per Year:	365	365	365	365	365	365	365	365	365	365
(103) Barrels Oil Per Year:	3537	3006	2555	2172	1846	1569	1334	1134	964	819
(104) Price Per Barrel:	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00	$18.00
(105) Barrels of Water Per Day:	390	392	393	394	395	396	396	397	397	398
(106) Total Fluid Per Day:	400	400	400	400	400	400	400	400	400	400
(107) MMCF Gas Per Day:	0	0	0	0	0	0	0	0	0	0
(108) MMCF Gas Per Year:	1	1	1	1	1	1	1	0	0	0
(109) Price Per MCF:	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50
INCOME STATEMENT FOR YEARS 21 - 30										
(110) Oil Revenues ($000):	$64	$54	$46	$39	$33	$28	$24	$20	$17	$15
(111) Gas Revenues ($000):	$2	$2	$2	$1	$1	$1	$1	$1	$1	$0
(112) Total Revenues ($000):	$66	$56	$48	$40	$34	$29	$25	$21	$18	$15
(113) Royalty Payments-Oil ($000):	$11	$9	$8	$7	$6	$5	$4	$3	$3	$2
(114) Royalty Payments-Gas ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(115) Severance Taxes-Oil ($000):	$8	$7	$6	$5	$4	$4	$3	$3	$2	$2
(116) Severance Taxes-Gas ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(117) Net Revenues($000):	$47	$40	$34	$29	$24	$21	$18	$15	$13	$11
(118) Operating Costs:	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40
(119) Pollution Control Operating Costs:	$50	$50	$50	$50	$50	$51	$51	$51	$51	$51
(120) Operating Earnings ($000):	($43)	($50)	($56)	($62)	($66)	($70)	($73)	($76)	($78)	($80)
(121) Earnings Before Interest and ODA:	($43)	($50)	($56)	($62)	($66)	($70)	($73)	($76)	($78)	($80)
(122) Adjsted Depletion Allowance:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(123) Surplus Depletion:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(124) Earnings Before Interest and Taxes:	($43)	($50)	($56)	($62)	($66)	($70)	($73)	($76)	($78)	($80)
(125) Federal Tax (Earnings-State taxes):	($13)	($16)	($18)	($19)	($21)	($22)	($23)	($24)	($24)	($25)
(126) State Tax:	($3)	($4)	($5)	($5)	($5)	($6)	($6)	($6)	($6)	($6)
(127) Earnings Before Interest After Tax:	($26)	($31)	($34)	($37)	($40)	($42)	($44)	($46)	($47)	($55)
(128) Net Cash Flow:	($26)	($31)	($34)	($37)	($40)	($42)	($44)	($46)	($47)	($55)
(129) Shutoff?	0	0	0	0	0	0	0	0	0	0
(130) Actual Oil Prod./Year (Barrels):	0	0	0	0	0	0	0	0	0	0
(131) Actual Gas Prod./Year (MMCF):	0	0	0	0	0	0	0	0	0	0
(132) Actual Gross Revenues ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(133) Actual Net Revenues ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(134) Actual Net Cash Flow ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(135) Actual Taxes Paid ($000):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

MODEL OUTPUT

(136) PV of Net Cash Flows:	$2,622
(137) PV of Excess Depletion:	$0
(138) PV of Surplus Depreciation:	$0
(139) PV of Expensed Invest Cash Flows:	$0
(140) PV of Capitalized Costs:	$0
(141) PV Poll. Cont. Costs:	$305
(142) PV of Royalties - Oil:	$1,124
(143) PV of Royalties - Gas:	$37
(144) PV of Severance Taxes - Oil:	$843
(145) PV of Severance Taxes - Gas:	$9
(146) PV of Operating Costs:	$342
(147) PV of Income Taxes:	$1,692
(148) PV of Total Company Costs:	$4,353
(149) PV of Total Company Costs - Oil:	$4,231
(150) PV of Total Company Costs - Gas:	$122
(151) Annualized Poll.Cont.Costs:	$32
(152) PV Equiv. of Oil Prod.(bb):	374,663
(153) PV Equiv. of Gas (MMCF):	150
(154) PV Barrels of Oil Equiv. (BOE):	401,045
(155) Amortized Company Cost per bbl:	$11.29
(156) Amortized Company Cost per MCF:	$0.81
(157) Amortized Company Cost per BOE:	$10.85
(158) PV of Social Costs - Total:	$647
(159) PV of Social Costs - Oil:	$626
(160) PV of Social Costs - Gas:	$21
(161) Amortized Social Cost/bbl:	$1.67
(162) Amortized Social Cost/MCF:	$0.14
(163) Amortized Social Cost/BOE:	$1.61
(164) Years of Production:	17
(165) Net Present Value of Project:	$2,622

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TABLE C-1

EXOGENOUS VARIABLES USED IN THE GULF OF MEXICO PRODUCTION LOSS MODEL

Line Number	Parameter
2	Real discount rate
3	Inflation rate
4	Federal corporate income tax rate
5	State corporate income tax rate
6	Corporate structure (major or independent)
7	Water:oil or water:gas ratio
8	Oil and gas production decline rate
9	Cost escalator
10	Royalty rate
12	Depreciation schedule
13	Severance tax rate—oil
14	Severance tax rate—gas
15	Gas-only flag
18	Oil—initial production rate (bbl/day)
19	Gas—initial production rate (MMcf/day)
22	Wellhead price per barrel—oil
23	Wellhead price per Mcf—gas
24	Total operating costs
25	Pollution control equipment annual cost (per barrel of water)
26	Days of production per year

Source: EPA estimate.

appeared to be a hurdle rate (values greater than 20 percent), or if the value were extremely low (less than 4 percent), the survey average nominal rate of 10.85 percent was substituted.

Line 4 presents the marginal Federal corporate income tax rate. Line 5 presents the state corporate tax rate. This rate changes depending on the state in which the well is located. For Texas, the state corporate tax rate is 0 percent, while for Louisiana, the rate is 8 percent (CCH, 1991). Line 6 shows the corporate structure. The corporate structure is important in the treatment of the adjusted depletion allowance shown in line 48 and discussed below.

In the production phase of a well, a variety of financial and engineering variables interact to form the economic history of a well. Line 7 provides the water to oil or water to gas ratio for the well. As discussed previously in this appendix, this rate is important to determine the future water production of the well and to adjust the incremental operating costs appropriately. Line 8 provides the production decline rate for oil and gas. The EPA model incorporates an exponential function for production decline, i.e., a constant proportion of the remaining reserves is produced each year. The decline rate predicted for the Gulf of Mexico coastal wells is 0.85 barrel, so each year, a well produced 15 percent less oil.

The EPA model is capable of handling cost escalation (see line 9). In this report, we are considering costs in real terms, and thus no escalation is assumed.

The royalty rate paid to the lessor of the land is provided in line 10. This value is a well-specific rate determined from survey data. If the rate is above 50 percent, which was considered an unrealistic response in the survey, the rate is adjusted to 16.6 percent for oil or 16.9 percent for gas. State severance taxes on oil and gas are given in lines 13 and 14 (CCH, 1991).

Line 15 is a flag to identify gas-only projects. The flag is necessary for the proper calculation of depletion on a cost basis within the code.

The number of years that a well produces at its initial rate is given in line 17. The initial production rates for oil and gas are given in lines 18 and 19, and are from Section 308 survey

data provided for the well. These rates decline annually per the production decline rate in line 8.

The wellhead price of oil per barrel and the wellhead price of gas per Mcf are given in lines 22 and 23. These values are from the Section 308 survey data.

The operating cost for the well is shown in line 24. The estimated operating cost was determined by dividing the operating costs for coastal oil and gas operations reported in the survey by the number of coastal wells operated, also calculated from the survey data. The resulting value is the estimate of operating costs for a coastal well operated by the survey respondent. No data was collected on the annual operating costs for specific wells.

The incremental pollution control costs for produced water are given in line 25. The cost indicates the incremental per-barrel of produced water cost by which disposal costs will increase because of the regulation. The per-barrel cost is obtained by determining an annual cost (annualized capital cost and O&M cost) from the produced water disposal option engineering costs and dividing that cost by the permitted produced water volume given in the state discharge permit for produced water. The total incremental cost is determined by multiplying this value by the barrels of water produced each year. The incremental cost increases each year with the increase in water production modeled with the constant-fluid assumption.

Line 26 shows the number of days per year the well operates. It is assumed that the wells in the production loss model operate continuously.

Line 27 indicates the barrels of oil per day produced by the well. Along with the number of days of production per year (the value in line 26 repeated in line 28), the model calculates the number of barrels of oil produced annually (line 29). Line 30 is the price per barrel of oil, repeated from line 22 above, to calculate the revenues generated from that production. Line 31 shows the barrels of water produced per day. Line 32 calculates the sum of the two fluids to check that total fluid is constant, since the volume of oil and water is assumed constant over time.

Lines 33 through 35 calculate the total volume of gas generated per year (note that the zeroes in line 33 are rounded values: the well actually produces approximately 100 Mcf per day in model year 1). With the price of gas in line 35, total gas revenues are calculated.

C.2.2 Income Statement

Lines 36 through 54 comprise an income statement that is repeated annually for a 30-year project lifetime. Since some projects become uneconomical before this, lines 55 checks for a negative net cash flow and readjusts the actual production, revenues, and cash flows to zero when appropriate in lines 56 through 63.

Lines 36 and 37 list the revenues from oil and gas production and sum to total gross revenues in line 38. Royalty payments (lines 39 and 40; see line 10 for the royalty rate) are calculated on the basis of gross revenues. Severance taxes are calculated on the basis of gross revenues minus royalty payments (lines 41 and 42; see lines 13 and 14 for severance tax rates). Net revenues for the year are calculated as:

Net Revenues = Total Gross Revenues - Royalty Payments - Severance Taxes

For Year 1 for the model well, net revenues are calculated as:

$$\text{Net Revenues} = \$1{,}697 - \$274 - \$9 - \$205 - \$2$$
$$= \$1{,}207$$

Operating costs are given in line 44; incremental operating costs for pollution control appear in line 45, and are the product of the per-barrel of produced water cost times the number of days of operation times the pollution control equipment operating costs.

The operating earnings (line 46) are defined as net revenues (line 43) minus operating costs (line 44) minus pollution control operating costs (line 45). For Year 1 of the project:

Operating Earnings = Net revenues - Operating costs - Pollution control operating costs

= $1,207 - $40 - $19 = $1,148

Line 47, earnings before interest and ODA (oil depletion allowance), would subtract depreciation and amortization from operating earnings. Because there are no capital costs considered (aside from those included in the per-barrel pollution control costs discussed above), both depreciation and amortization are zero, hence line 60 equals line 59.

The depletion allowance (line 48) is calculated based on the leasehold cost and the annual production of the well. If the project ends while a depletion allowance may still be taken, the depletion allowance in that year and subsequent years is termed "surplus depletion" (line 49). In the Gulf model, depletion for major producers is zero because there are no leasehold costs included and major producers deplete on a cost basis. Independent producers deplete on a percentage basis (see Appendix A), and therefore have a value for the oil depletion allowance.

Earnings before interest and taxes (EBIT) in line 50 is defined as the earnings before interest and ODA (line 47) minus the adjusted oil depletion allowance (line 48).

The earnings in line 50 form the basis for state taxes, shown in line 52. Federal taxes are then calculated on the difference between EBIT and state taxes. Federal income taxes are shown in line 51. Earnings after taxes are given in line 53.

The project cash flows, line 54, are determined by adding non-cash expenses, depreciation, and depletion to earnings after taxes. The net cash flow for Year 1 is $697, since both depreciation and depletion are zero.

The cash flows forecasted for the project may or may not be sufficient to justify continuation of operations. In some circumstances, net cash flows may be positive only because of large values for depreciation, e.g., where large capital expenditures are required on a small project or later in the operating life of the project. Under these circumstances, the project is likely to shut down even though cash flow is positive. Since the capital costs are allocated on a per-barrel cost, it is likely that in the later stages of a well's production, the revenue from oil and

gas production will be insufficient to cover the increasing operating costs for produced water disposal. If net cash flow is equal to or less than zero in any given year, the project is assumed to shut down. The model prints a "1" in line 55 for years in which the project operates and a "0" for years in which the project does not operate.

In the event that the project is shut down, certain variables must be recalculated to reflect that decision. Lines 56 through 61 restate production volumes, revenues, and cash flow in light of the shutdown; that is, production and revenues are set to zero after the project shuts down. Other project variables, such as depreciation, are recalculated because of the earlier shutdown date. Unexpended capitalized costs and surplus depreciation are given in lines 62 and 63 .

The production information for the second and third decades of operation are found in lines 64 through 72 and lines 101 through 109, respectively. The corresponding income statements are shown in lines 73 through 100 and lines 110 through 135.

C.2.3 Summary Statistics

At the end of the project, all costs and revenues are put in present value terms as of the base year; see lines 136 through 165.

The present value (PV) of total company costs (line 149) is the summation of the present values of the parameters listed in lines 139 through 148, subtracting PV of excess depletion (line 137) and PV of surplus depreciation (line 138). This parameter provides a measure of the present value of net company resources expended in operation of the petroleum project.

Total company costs for oil are the present values for oil royalties and severance taxes and the oil portion of the remaining costs (see line 149). These costs are apportioned by the ratio of oil revenues to total revenues. An analogous procedure is followed to obtain the total company cost for gas (see line 150).

The capital and the annual operation and maintenance costs for incremental pollution control of produced water effluents are given in terms of present value and are annualized over the economic lifetime of the well. The annualized cost is given in line 151. This is the annualized cost of the pollution control costs that were incorporated into the model on a per-barrel of produced water basis.

Oil and gas production is also discounted to give present value equivalent (see lines 152 through 154). Corporate costs per barrel and corporate costs per Mcf are obtained by dividing the present value of the company cost by the present value equivalent of production (see lines 155 through 157).

The present value of social costs (lines 158 through 160) provides a measure of the value of net social resources expended in the development and operation of coastal petroleum projects. The difference between company cost and social cost is that the social cost ignores the effects of transfers that do not use social resources. The items included in social cost are operating costs and investment costs. Social cost per unit of production is obtained by dividing the social cost by the present value equivalent of production (lines 161 through 163).

The number of years the project operates is shown in line 164. This number reflects the total number of years that well operates with a positive cash flow.

The net present value of the project, line 165, is calculated as:

Net Present Value = PV of Cash Inflows − PV of Cash Outflows

= PV of Operating Cash Flows
− PV of Expensed Investment Cash Flows
− PV of Capitalized Costs
− PV of Leasehold Costs
+ PV of Excess Depletion
+ PV of Surplus Depreciation

A positive net present value is indicative of a profitable project at the assumed discount rate, i.e., it generates more revenue that investing the capital in a project with that expected rate of return.

C.3 REFERENCES

CCH 1991. *State Tax Handbook*, Commerce Clearing House, Inc., 1991.