Outer Continental Shelf
Oil & Gas

# 5-Year Leasing Program Mid-1987 to Mid-1992

Proposed Final

MMS U.S. Department of the Interior
Minerals Management Service

**Outer Continental Shelf**
**Oil & Gas**

Detailed
Decision Documents

# 5-Year Leasing Program Mid-1987 to Mid-1992

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**Minerals Management Service**

April, 1987

CONTENTS

# United States Department of the Interior

MINERALS MANAGEMENT SERVICE
WASHINGTON, DC 20240

APR 16 1987

MEMORANDUM

To: The Secretary

Through: Assistant Secretary - Land and Minerals Management

From: Director, Minerals Management Service

Subject Summary: Adoption of a Proposed Final 5-Year Outer Continental Shelf (OCS) Oil and Gas Leasing Program for mid-1987 to mid-1992--Request for Secretarial Action

## DISCUSSION

Section 18 of the OCS Lands Act (OCSLA), as amended, requires you to prepare and maintain an oil and gas leasing program for the U.S. OCS. It also requires that, "[t]he leasing program shall consist of a schedule of proposed lease sales indicating, as precisely as possible, the size, timing, and location of leasing activity which [the Secretary] determines will best meet national energy needs for the five-year period following its approval . . . ."

The Minerals Management Service (MMS) has reviewed comments on the Proposed Program which you issued in February 1986, revised the analysis, and restructured the options for the Proposed Final 5-Year OCS Oil and Gas Leasing Program for the period mid-1987 to mid-1992. The options analyzed in the Secretarial Issue Document (SID) and the Environmental Impact Statement (EIS) for the new program were also revised to include those options for OCS leasing offshore California specified by Public Law (P.L.) 99-591.

Pursuant to P.L. 99-591, on February 2, 1987, you submitted a draft copy of the offshore California elements of the proposed final leasing program for the OCS to the cochairmen of the special congressional panel for a 30-day review. That submission included a comparison of the California portion of your Proposed Program (updated) with the proposal of the California Governor and the two proposals developed by the special congressional panel established by P.L. 99-190. A summary of comments received on the Draft Proposed Final Program for the OCS offshore California is attached.

Your selection of a Proposed Final Program will be submitted to the Congress and the President. In compliance with section 18 of the OCSLA, that submission will include copies of letters to Governors with responses to comments on the Proposed Program from their State and its local governments; and a copy of a comparable letter to the Attorney General. As required by P.L. 99-591, the submission will also provide responses concerning specific portions of the California proposals specified by that law which were not accepted. After a 60-day waiting period, you can give final approval to the new program.

Prepared by: Paul R. Stang Ext.: 343-1072

In connection with the Proposed Final Program, we are asking you to select the following:

- a configuration of planning areas (including possible deferral or other treatment of subareas);
- a leasing schedule;
- a presale process leading to decisions on the size of individual lease sales; and
- provisions to assure receipt of fair market value.

Attached for your use in making these selections are:

- two decision sheets: one for 5-year program elements specified by section 18 of the OCSLA; and one for decision options which go beyond those elements specified by section 18 (Attachment 1);
- three alternative leasing schedules (Attachment 2);
- maps of the proposed OCS planning areas (Attachment 3);
- the Proposed Final Program SID, Appendices, and Subarea Attachment (Attachment 4); and
- a summary of comments on the February 1987 Draft Proposed Program for OCS leasing offshore California (Attachment 5).

The final EIS for the 5-Year Program (which includes an environmental analysis of the California proposals pursuant to P.L. 99-591 as well as an analysis of alternative energy sources) was transmitted to you on January 28, 1987. The California Analysis which you used in making your February 2, 1987, decision on the Draft Proposed Final Progam for the OCS offshore California has not been revised for this decision because the Proposed Final Program decision is one for the Nation's whole OCS. Any revisions of analysis relative to OCS leasing offshore California appear in the SID or this decision memorandum.

The SID includes an analysis of specific factors which section 18 requires you to consider in formulating a 5-year leasing program. These factors, most of which are analyzed and arrayed by OCS planning area in the SID, include, <u>inter alia</u>:

- geographical, geological, and ecological characteristics;
- equitable sharing of developmental benefits and environmental risks;
- relative needs of regional and national energy markets;
- other uses of the sea and seabed;
- interest of potential oil and gas producers;
- laws, goals, and policies of affected States;
- relative environmental sensitivity and marine productivity; and
- environmental and predictive information.

You are required to consider these factors and the views of Governors of affected States and other parties in the selection of the timing and location of leasing "so as to obtain a proper balance between the potential for environmental damage, the potential for the discovery of oil and gas, and the potential for adverse impact on the coastal zone." Furthermore, the leasing program must be prepared and maintained in a manner consistent with the principle that leasing activities be conducted to assure receipt of fair market value for lands leased and rights conveyed.

## THE FEBRUARY 1986 DECISION ON THE PROPOSED PROGRAM

As a point of reference, the Proposed Program, which you issued in February 1986, slows the pace of leasing in comparison with the current program. It contains the following provisions:

- sales in 21 planning areas, including 27 standard sales, 10 frontier exploration sales, and 5 small supplemental sales;
- no sales in St. Matthew-Hall, Aleutian Arc, Aleutian Basin, Bowers Basin, or the Straits of Florida;
- deferral of leasing in 15 subareas and highlighting 13 others for further analysis and comments;
- a provision to accelerate sales in up to eight areas of higher value and/or higher interest (a provision dropped from further consideration by your decision of September 8, 1986);
- a presale process which focuses on promising acreage; and
- sale-by-sale review of current procedures for assuring the receipt of fair market value and the basic approach of $150/acre as the minimum bid.

## THE VALUE OF FLEXIBILITY

In 1981-82, when the analysis and decision process for the current program were underway, many analysts predicted that the price of oil and gas would continue to climb. Estimates of world oil prices reaching $60 (1982 dollars) per barrel or more by the end of the century were common. When this analysis was initiated in 1984, the price of oil was $29 per barrel (average free on board U.S. import price weighted by import volume), down from $34 in 1982. Over the last 2 years, prices have declined. There was a rapid drop to about $9 per barrel in mid-1986 and a subsequent rise to about $17 as of March 1987.

It is not clear what price trend can be expected in the future. There is a far greater sense of uncertainty in perceptions and a far lower range of projections of future energy prices now than existed in 1981-82. The debate then was whether real price increases would be 1, 2, 3, or more percent per year. The current debate concerning near-term oil prices focuses on projections of moderate increases, stagnant prices, and further declines. The longer-term price trend, however, is generally agreed to be upward from the starting point of the economic analysis for the SID in 1984 (see Figure 1 of the SID). Currently adequate oil supplies and relatively low oil prices can obscure the need to take steps now to find adequate oil supplies through the rest of this century and the beginning of the next--for that is the period of production from areas leased in the new 5-year program.

The recent (March 1987) report by the Department of Energy titled Energy Security--A Report to the President of the United States presents a comprehensive analysis of the current and projected energy needs of the United States within the context of our energy and national security interests in the next decade (see especially pages 29-30). The report analyzes and projects the supply of and the demand for all our sources of energy--oil, coal, natural gas, nuclear power, electricity, renewables--as well as the opportunities for achieving greater efficiency in energy use. It is clear that oil is and will continue to be a vital component of our energy mix well beyond the year 2000. U.S. oil is characterized in the report as our critical resource at risk. The U.S. economy's use of oil is concentrated in our large transportation sector, which accounts for over 60 percent of the oil we consume as a Nation.

The major source of our increasing oil imports has been and is projected to be the politically unstable region of the Middle East with its tremendous reserves and low costs of extraction. The report cautions that despite the many gains the U.S. has made in building a stronger foundation of energy security, the enormous toll in our domestic petroleum sector resulting from the recent world oil price declines portends serious problems for the future.

In formulating this leasing program, it is important to recognize that substantial economic benefits may be realized from production of oil and gas found on OCS acreage that is leased during the 5-year term of the program. Such leases will come from acreage that is unleased as of mid-1987 or from currently leased acreage which is surrendered and leased again. Such potential benefits have made the OCS program one of the most beneficial of the Government's economic programs. In addition, the potential benefits would be realized largely in the form of Federal revenues which will help reduce future Government deficits.

The 5-year leasing program can influence the benefits realized because it controls the availability of investment opportunities in exploratory drilling on unleased OCS acreage. Thus, in substantial measure, the program controls the ability of firms to adjust their OCS investments to emerging conditions in the world oil market. If you choose a leasing program with relatively small sales at less frequent intervals in fewer areas, the range of possible investments will be more limited. Such a choice may permit investors in OCS exploration to respond adequately to relatively low and stable world oil prices but might not permit expanded leasing and exploration in response to higher price expectations. On the other hand, if you choose a leasing program with relatively large sales at more frequent intervals in more areas, the range of possible investments is likely to be greater.

Thus, while a more extensive leasing program could yield the same level of investment as a more restrictive program assuming lower price expectations in the future, a restrictive program would not allow substantial expansion in leasing and subsequent exploration if world oil prices and expectations were to rise. This is because the program cannot be scaled up without reinitiating the multiyear approval process prescribed by section 18. The cost to the Nation of such delay could be substantial.

This flexibility principle also applies to consideration given to the California proposals for the 5-year period mid-1987 to mid-1992 and especially to the elements of those proposals which extend further into the future. Long-term restrictions on leasing and subsequent development limit flexibility to respond to changing national needs for oil and gas, potential increases in the price of oil, evolving technology, and advances in geological and geophysical information. Flexibility in the program, however, needs to be balanced with stability to maintain public confidence and to allow affected parties and the oil and gas industry to plan efficiently.

## SECTION 18 ANALYSIS

Both the June 1980 and the July 1982 5-year programs were challenged in the U.S. Court of Appeals for the District of Columbia Circuit. The court found that the section 18 analysis performed for the 1980 program did not fully comply with the statute but that the 1982 program formulation fully complied with the statute and the guidance the court had set forth in its opinion on the 1980 program.

The analysis undertaken for the Proposed Final Program is very similar to, but more extensive than, that conducted for the July 1982 program. For instance, updated estimates have been made of undiscovered oil and gas resources, economic benefits to the Nation, and environmental effects for the planning areas to show more specifically how the potential benefits and costs of leasing may be affected by changes in the world oil market. In order to reflect the uncertainty inherent in future oil prices, economic benefits were projected assuming a range of oil prices from the actual 1984 price of \$29 per barrel to an assumed low price of \$14 per barrel in conjunction with a real oil price increase of 1 percent and an 8 percent discount rate. These projections were supplemented with sensitivity analyses using prices of \$34 and \$9 per barrel, real oil price increases of 0 and 2 percent per year, and a 6 percent discount rate.

Both the per barrel and total estimated economic benefits for unleased, undiscovered resources are lower than those of the 1982 analysis. These reductions are attributable, in part, to leasing since 1982 and projected leasing through mid-1987, as well as the decline in oil prices and price expectations. Disappointing exploration results, especially on the Alaska and Atlantic OCS, also contributed to declines in the resource estimates. Most estimates of potential social costs (environmental and other costs not normally included in the producer's cost of OCS operations) which might result from production are also lower than those of the 1982 analysis, but the decrease for most planning areas is much more substantial than the decrease in economic benefits. This is due not only to a reduction in projected leasable resources and an improved safety record but also to a revision of the assumptions used in the 1982 analysis which, in retrospect, greatly overstated potential social costs.

Whenever production is economic in any planning area, estimated net social value (the difference between estimated economic benefits and estimated social costs) is so large that the social costs would have to be many times larger than estimated in order to reduce the expected net social value to zero. Tables 12.1 and 12.4 in the SID show that estimated economic benefits are many times larger than the estimated social costs in each planning area for which there are estimated leasable resources.

LOCATION, TIMING, AND SIZE

The following discussion of comments on and options for location, timing, and size of leasing incorporates the factors which you are required to consider under section 18 in formulating the new 5-year program.

Comments on the February 1987 Draft Proposed Final Program

A detailed summary of comments on the February 1987 Draft Proposed Final Program for OCS leasing offshore California is attached to this decision memo. Note that comments on the February 1987 Proposal were received from the Governor of California, Congressman Regula, and Congressman Panetta of the special congressional panel established pursuant to P.L. 99-190, other members of Congress, State and local government entities, and public interest groups. Generally speaking, comments ranged from those of Governor Deukmejian, Congressman Regula, Senators Johnston and McClure, and 13 other members of Congress (which characterized the February 1987 amalgamated proposal as a major step in addressing the controversial issues surrounding an OCS leasing program offshore California) to those of Congressman Panetta and 27 other members of Congress (which characterized the proposal as an abandonment of the attempt to achieve consensus on leasing offshore California).

On one hand, approval of the triennial pace of leasing, dropping the acceleration provision, and postponing supplemental sales until after implementing regulations are issued were viewed by the Governor as a critical reaffirmation of the OCS Lands Act process and the protection it provides to State and local government interests. The Governor also commended the commitment in the proposal to provide environmental protection comparable to that negotiated for OCS Lease Sales 73 and 80 and specifically stated that his recommendations for air quality protection, use of pipeline transportation, addressing onshore facility capacities, and protection for military training and operating areas reflect the minimum acceptable protection for leasing offshore California. The Governor also indicated that there are still many portions off the California coast where sufficient information exists to justify their deletion from the 5-year program in full accord with the OCS Lands Act. Congressman Regula indicated that anything that could be done to demonstrate the commitment to such stipulations would be helpful and that the safeguards contained in the proposal were considered to form a basis for further negotiations on remaining areas of disagreement and the development of additional protection measures unique to specific areas through the lease planning process.

On the other hand, correspondence from Congressman Panetta and numerous State and local government agencies indicated that the proposal did not represent a compromise; did not provide adequate protection for the unique resources of the California coast; ignored the needs of local governments to plan for development; did not provide for any long term protection of the resources offshore California; did not contain adequate deferrals; and represented an exponential increase in the number of tracts to be offered for lease well beyond the range discussed during congressional discussions with the Department.

Comments on the February 1986 Proposed Program

More than 3400 comments were received in response to the release of the Proposed Program in February 1986, 93 percent of which came from Californians. A brief summary of comments on the Proposed Program appears in the Introduction to the SID and in the discussion of each of its options, while a detailed summary appears in Appendix B.

Location Comments

Many Governors endorsed the Proposed Program's deferral of specific subareas from the leasing program. The Governors of Maine, Massachusetts, Connecticut, New Jersey, Delaware, Maryland, Virginia, North Carolina, Florida, California, Oregon, Washington, and Alaska also recommended specific additional subareas for deferral from the leasing program.

Petroleum industry commenters generally opposed deferral of subareas from planning areas. Two companies did endorse some of the Proposed Program's deferrals, but most industry commenters stated that any deferral decisions should be made during the presale process conducted for individual sales.

Several commenters addressed the scheduling of sales in particular planning areas. The Governor of Florida, a number of local governments, members of Congress representing Florida, and others recommended deferring the entire Straits of Florida planning area from the leasing program. Requests for the deferral of leasing below 25° N. latitude in the Eastern Gulf of Mexico were received from the Florida Department of Environmental Regulation, a member of Congress, and a number of environmental groups. Seven industry commenters expressed support for scheduling a sale in the southern portion of the Straits of Florida planning area. The Governor of Alaska recommended deferring the North Aleutian Basin planning area.

Timing Comments

The Governors made extensive comments concerning the number of sales proposed and the interval between them. Maine, Rhode Island, New Jersey, Delaware, North Carolina, and Florida endorsed the pace of leasing proposed for the Atlantic planning areas. Massachusetts expressed opposition to scheduling two sales in the North Atlantic planning area and a total of four sales in the Atlantic planning areas.

Florida commented in support of triennial leasing in the Eastern Gulf of Mexico planning area. Alabama, Louisiana, and Texas expressed opposition to decreasing the rate of leasing to triennial sales outside the Central and Western Gulf of Mexico planning areas on the grounds that a slower pace of leasing elsewhere in conjunction with annual leasing in those Gulf of Mexico areas placed an unfair burden on them.

California endorsed triennial leasing and commented that initiation of the presale process for Sales 91, Northern California, and 95, Southern California, should be postponed until after the 5-year program is approved. Washington requested that Sale 132, Washington-Oregon, scheduled for 1991, be delayed to allow completion of environmental studies for consideration in the presale process.

Alaska reiterated its longstanding request that the lease schedule include a maximum of three sales per year off Alaska and a total of no more than 12 sales off Alaska during the 5-year period. They also recommended that Sales 127, Kodiak, and 129, Shumagin, be removed from the schedule and urged that no sales be scheduled in the North Aleutian Basin planning area until 1994.

The majority of industry commenters endorsed annual leasing in the Central and Western Gulf of Mexico planning areas and expressed support for biennial leasing in other planning areas. Six companies specifically recommended a biennial pace for the Eastern Gulf of Mexico, and two commented in favor of triennial leasing in that planning area. Two companies specifically endorsed the triennial pace proposed for leasing in the Alaska OCS planning area.

Options for Location and Timing

Determining the location and timing of leasing requires decisions on the configuration of planning areas to be offered for lease (including possible subarea deferrals), the selection of planning areas to be included in the schedule, and the frequency of sales in each planning area.

Since the February 1986 request for public comments (reproduced in Appendix M of the SID), modifications of planning area boundaries have been made to extend the three Gulf of Mexico planning areas and the Straits of Florida planning area. This revision would make the added area available for consideration for leasing in the new 5-year period, given the historic trend toward drilling in ever-deeper waters in the Gulf of Mexico.

You are requested to: confirm the configuration of planning areas on which the section 18 analysis has been performed; and determine which subareas will be deferred from leasing in the 5-year program or highlighted for consideration during the presale process of individual sales.

The quantitative analyses in the SID provide part of the basis for your determination as to where sales should be scheduled. If the estimated benefits of oil and gas production in an area exceed the estimated costs, the area should be considered further for inclusion in the 5-year program. Wherever resources are projected, the net social value calculations for the planning areas show benefits exceeding costs. Similarly, with respect to timing, the planning areas are grouped by net social value as a guide in deciding the frequency of sales in a particular planning area. In general, the higher the net social value group, the more frequently sales could reasonably be scheduled in that area, subject to the other considerations discussed below.

The quantitative analysis in the SID has been revised to account for the subarea deferrals you adopted for the Proposed Program. These deferrals are reflected in both the net social value calculations for the planning areas (Table 12.1 in the SID) and the valuation of program alternatives discussed below.

You designated other subareas for further analysis and comment. Estimates of the effect of deferral of these (as modified by the Assistant Secretary - Land and Minerals Management in fall 1986, based on consideration of comments) and several other subareas on the planning area values are shown in Table 12.4 of the SID. These estimates include the subarea deferrals of the California proposals and those recommended in the Institute for Resource Management proposal for the Bering Sea planning areas. In addition, the description of subarea deferrals recommended by commenters is presented in the Subarea Attachment of the SID. It should be noted on one hand that deferral of one or more additional subareas within a planning area could change the estimated resources and net social value group for the remainder of the planning area (if the subareas include significant prospects). On the other hand, estimated resources and net social value may not change appreciably if a subarea deferral is assumed. Given the uncertainty of projecting undiscovered resources and their future value, however, such a lack of change should not be interpreted to mean that no resources or value would be foregone. Such matters should be considered in your decisions on the frequency of leasing in that planning area.

By using the results of the section 18 quantitative analysis and industry interest rankings (see Tables 13.1-13.4 of SID), an updated base schedule (Option A.2.a) and six possible amendments (Options A.2.b to A.2.g) have been developed for your consideration. While many combinations are possible, three schedules (see Attachment 2) showing all sales in Options A.2.a, A.2.d, A.2.e, and A.2.g have been developed. The other options (A.2.b, A.2.c, and A.2.f) and combinations thereof are relatively easy to envision and thus are not shown. The leasing activity which would result for each of these schedules is as follows:

| Schedule* | Maximum Number of Sales | Number of Planning Areas |
|---|---|---|
| Options A.2.a & A.2.e | 36 | 21 |
| Options A.2.d & A.2.e | 41 | 21 |
| Option A.2.g (revises Options A.2.a & A.2.e) | 34 | 20 |

*Note that these schedules exclude St. Matthew-Hall, Aleutian Basin, Bowers Basin, and Aleutian Arc and do not count supplemental sales.

Option A.2.a would schedule annual sales in the two areas in net social value Group I (Central and Western Gulf of Mexico) where net social value is by far the highest; triennial sales in all areas in Group II where net social value is positive at both ends of the assumed price range; and areas in Group III where net social value is positive at least at the high end of the assumed price range (see section II.D. of the SID).

Option A.2.b would add a sale in the Straits of Florida planning area below 25° 07' N. latitude in 1992. It should be noted that such a sale has been strongly opposed in correspondence from the Governor of Florida, a number of members of Congress, and numerous Floridians.

Option A.2.c would defer leasing in any or all of the following six planning areas which have been the focus of opposition to leasing: North Atlantic; Southern California; Central California; Northern California; Washington-Oregon; and North Aleutian Basin.

Option A.2.d would revise the schedule for Option A.2.a by offering biennial sales in up to eight higher value and/or higher interest areas: Southern California; Central California; Northern California; Eastern Gulf of Mexico; Beaufort Sea; Navarin Basin; North Aleutian Basin; and St. George Basin.

Generally, these areas are relatively highly ranked by MMS in terms of net social value (see Table 12.1) and/or by industry (see Tables 13.1, 13.2, and 13.3). Indeed, these eight areas include those ranked highest--after the Central and Western Gulf of Mexico--in industry interest as expressed in summer 1984 and confirmed in spring 1985 and spring 1986. Two exceptions, however, are worthy of note. First, the Chukchi Sea is not a part of this option--even though it was ranked ninth in the spring 1986 industry ranking--because Sale 109 is the first sale to be held in this area. In such a case, a triennial schedule is more appropriate than a biennial one, so that the results of the exploratory drilling efforts following the first sale can be considered in preparing for the second sale. Second, St. George Basin, which industry ranked relatively high in summer 1984 has, as of spring 1986, dropped to 12th, behind North Atlantic (which was designated as a frontier exploration sale area in the Proposed Program). Indeed, St. George Basin has become a candidate for such designation, as described below in relation to Option A.2.e.

Option A.2.e would designate nine frontier exploration sales. Suboption A.2.e.i would parallel your choice for the Proposed Program, while suboption A.2.e.ii would designate as frontier exploration sales new sales in St. George Basin and/or Norton Basin. Navarin Basin could also be considered for inclusion in this category based on its ranking (10th) in spring 1986 comments by industry and the results of surveys of industry interest concerning Sale 107. Frontier exploration sales in net social value group II and III areas are proposed triennially, whereas such sales in group IV areas are proposed as single sales. The presale process for a frontier exploration sale is the same as for a standard sale once the Call for Information and Nominations is issued. Prior to issuance of the Call, however, it is highlighted for consideration of an additional presale step (a Request for Interest scheduled for 4 months prior to the Call for Information and Nominations, to help determine whether the rest of the presale process should proceed) that may be added if MMS does not already possess adequate industry interest data. This represents a change from the Proposed Program, where frontier exploration sale designation meant that such a sale would always begin with a Request for Interest. It remains true, however, that frontier exploration sales would be proposed for areas where there is greater uncertainty regarding industry interest. In addition, as part of the annual review of the 5-year program, an assessment would be made of the utility of continuing with these sales.

Option A.2.f would schedule annual supplemental sales of combinations of selected blocks in areas other than the Central and Western Gulf of Mexico. These sales would offer development blocks and blocks on which bids were rejected or bid deposits forfeited in a prior period. Consideration of offering blocks where bids were forfeited as well as rejected represents a change from the Proposed Program. Another such change is the provision allowing for the possibility of skipping a supplemental sale in one year while retaining the ability to offer the blocks that would have been offered in the next supplemental sale.

Option A.2.g would result in a schedule of lease sales providing additional responsiveness to comments of the Governor of Alaska (by deleting Sale 127, Kodiak) and the Governor of Washington (by delaying Sale 132, Washington-Oregon until 1992). This option would also reduce the burden on all parties by delaying Sale 119, Central California, until 1990 and scheduling a combined Gulf of Alaska/Cook Inlet sale, Sale 114, in 1991. Two other changes in the schedule of sales not included in this option could also be considered: Sale 114 could be scheduled in 1990 so that no more than three sales per year would be scheduled offshore Alaska, as requested by the Governor; and a delay of a year for the next two North Atlantic sales for additional presale consultation.

The schedules were derived on the basis of the ranking of planning areas by the quantitative results of the analysis of section 18 factors modified by the expression of industry interest when the two rankings differed significantly. For example, Beaufort Sea, Navarin Basin, St. George Basin, Chukchi Sea, and North Aleutian Basin, which were in the top half of the 26 areas ranked for interest by industry, were retained in Option A.2.a even though the leasable resources and net social value for those areas are estimated by MMS to be negligible in the low oil price case. Norton Basin, however, fell in industry interest rankings to 18th--the same relative rank as its net social value. Thus, while Norton Basin has been retained in the base schedule option, it has been added to Option A.2.e for possible designation as a frontier exploration sale because of its lower industry interest rank as well as in response to the request of the Governor of Alaska. On the other hand, Gulf of Alaska is ranked low by industry and thus was not included in Option A.2.a. Washington-Oregon is part of the triennial option, but the first sale is scheduled for late in the 5-year program, 1991, to allow time to generate additional environmental information. Also, Sale 91, Northern California, and Sale 95, Southern California, have been rescheduled to 1989 pursuant to P.L. 99-591.

To assist in selection of the schedule options, net social value estimates have been made for each option based on estimates of resources expected to be leased which are comparable to those used in the EIS. Table 17.2 in the SID shows these estimates for each alternative schedule and the Institute for Resource Management proposal, along with the corresponding present value estimate of the unleased, undiscovered oil and gas remaining at the end of the leasing period.

Similar estimates were made for five proposals for OCS leasing offshore California: your February 1986 Proposed Program; Governor Deukmejian's proposal of May 7, 1986; the two proposals (Congressmen Regula's and Panetta's) submitted by the cochairmen of the special congressional panel; and the Amalgamated Proposal you identified in your February 1987 Draft Proposed Final Program. These estimates (in Table 17.3 and Appendix R of the SID) show the net social value of the offshore California component of the 5-year program schedule (mid-1987 to mid-1992) and the value of the resources remaining thereafter. Appendix R shows a comparison of the California proposals for the periods 1987-1992, 1992-2000, and beyond 2000. In this way proposals can be compared by examining results for the 5-year program or results for the 13-year period specified by Congressmen Regula and Panetta. The tables and the balance of the California Analysis document were developed to help you compare the California proposals on a common ground--the estimated net benefits to the Nation.

Each of the schedules depicted in Attachment 2, as well as the schedules which would result from selection of other combinations of options, reflect different approaches to balancing the potential for environmental damage, the potential for the discovery of oil and gas, and the potential for adverse impact on the coastal zone. This balance is based primarily upon the quantitative estimates of economic benefits and social costs as well as industry interest. However, to determine the timing and location of lease sales to provide a proper balance, as required by section 18(a)(3), you should consider, in addition, all the qualitative information on section 18(a)(2) factors treated in the SID as well as public comments and the final EIS.

As indicated above, the attached analysis has been structured to be consistent with the court opinion upholding the 1982 program. However, the analysis should not be viewed as deterministic in any sense of the word. The framework for the analysis--planning for an uncertain future with limited information--sets the tone of the entire analysis. The estimates of undiscovered, unleased oil and gas resources and the economic benefits and costs of those resources are based on the best data available, but are subject to considerable uncertainty, as were the estimates in the 1982 analysis. To reflect this uncertainty, a range of starting oil prices (with a 1 percent real annual price growth and additional sensitivity analysis at $9 and $34 per barrel) is used in this analysis rather than point estimates as in the 1982 analysis. Oil prices used in the economic analysis for the SID are keyed to 1984 prices, so that the "low" to "high" range of "$14" to "$29" needs to be understood as corresponding to a range of approximately $15.75 to $32.50 in 1987 dollars as of the start of the new program. Of course, the most important prices for this decision are those which will prevail years in the future, at the time of production (see Figure 2 in the SID).

The social cost and marine productivity/environmental sensitivity analyses involve even more uncertainty than the economic benefits analysis. The rankings of industry interest are simple averages and do not represent the relative strength of individual company preferences or the size of holdings or exploration budgets of companies operating on the OCS. Furthermore, both the net social value and industry interest rankings are based on geologic data and economic/environmental assumptions which are highly subject to change as new information becomes available and analytical assumptions and techniques are refined. Such changes have the potential to alter the rankings, perhaps significantly. In light of these uncertainties and the requirement to consider all the qualitative as well as quantitative information required by section 18, an exercise of judgment is vital to meet the Act's balancing requirements for timing and location of lease sales.

Size Comments

The Governors submitted several comments regarding the presale process which determines the size of lease sales. Maine, New Hampshire, Rhode Island, Virginia, North Carolina, Florida, and Alabama generally endorsed the presale process of focusing on promising acreage. Comments submitted by Massachusetts, Delaware, Maryland, Georgia, and California also were favorable but requested clarification of specific aspects of the proposed process. Louisiana, Texas, and Alaska expressed opposition to the proposed process and stated a preference for a tract selection process.

The Governors also addressed the possible revisions of presale nomination procedures which were presented for comment by the Federal Register Notice announcing the Proposed Program (51 FR 4816). Maine, Massachusetts, New Jersey, and North Carolina expressed support for requiring submission of more detailed industry interest information prior to issuance of the Call for Information and Nominations and again after issuance of the draft EIS. Maine expressed opposition to requiring that more detailed information be submitted in making negative nominations.

Most industry commenters stated a preference for areawide leasing and perceived focusing on promising acreage as a process which would limit exploration strategies and opportunities. Some industry commenters did express support for applying the proposed process of focusing on promising acreage to planning areas other than the Central and Western Gulf of Mexico. Several comments expressed opposition to revising nomination procedures to require more detailed industry interest information prior to the Call and again after the draft EIS. Most industry commenters endorsed requiring more detailed negative nomination information, but one company opposed such a requirement.

Options for Size

Under section 18, the size of the sale to be included on the schedule is limited only by the Secretary's present intentions. In other words, you may include as much of the area within the planning area as you currently are "genuinely considering for leasing activity." (712 F.2d at 592) Ultimately, though, the size of individual lease sales is determined by the presale process. Part III.B of the SID presents options for the presale process: focusing on promising acreage; tract selection; and areawide leasing. Tract selection was used until early 1983, areawide in mid- to late 1983, and a more focused approach roughly comparable to the evolving "focusing on promising acreage" concept started in 1984.

For the Proposed Program, you selected focusing on promising acreage for the presale process. The SID includes a variety of options to further define the concept of focusing on promising acreage. Some of these were suggested to the Department in response to the Federal Register request for comments on the Proposed Program.

Tract selection as previously practiced differed from areawide leasing in two key ways: much less acreage was seriously considered for leasing; and more reliance was placed upon a consensus of Government and industry views in selecting the tracts to be offered for sale. Areawide leasing procedures allowed a far wider choice of tracts to be offered, providing opportunities for investment by firms with unique geological information and exploration strategies. Focusing on promising acreage identifies and offers acreage likely to lead to exploration and/or development of oil and gas resources. Focusing on promising acreage also provides for earlier resolution of conflicts than areawide leasing, especially for acreage with low resource estimates, low industry interest, and high use conflicts or high environmental value.

Regardless of which presale process is selected, it is important to note that size, in terms of acreage offered at a lease sale, is partially determined by the size of the planning area and its geology. In some planning areas, such as the Central and Western Gulf of Mexico, there are numerous interesting prospects scattered over large areas, while in others, such as the North Aleutian Basin, the most interesting prospects tend to be more concentrated. Furthermore, even when the geology is similar in two planning areas, the amount of acreage offered at a lease sale may be different if the planning areas are of different total acreage.

## MINIMUM BID AND BID ADEQUACY

The last two sets of options pertain to the minimum bid and bid adequacy.

### Minimum Bid and Bid Adequacy Review Comments and Discussions

Some Governors made comments with respect to assuring the receipt of fair market value for lands leased and rights conveyed. Florida and Texas stated that areawide leasing results in insufficient competition to assure the return of fair market value. California recommended retaining the current minimum bid for 8(g) blocks and stated that the Proposed Program did not present sufficient information for review of current fair market value procedures.

Industry comments on this topic generally recommended lowering or abolishing the current minimum bid. Several commenters suggested additional modifications to the leasing program to address prevailing low oil and gas prices. Suggestions were made concerning alternative bidding systems, tax credits, lower rental and royalty rates, and longer lease terms.

A number of commenters contend that the current 5-year program lowers the average bid per acre and thus does not achieve fair market value. As described in Appendix P, the rates of leasing that result from different presale procedures may affect the average bid per acre or the average number of bids per tract. For example, the average number of bids per tract may be less in large sales than in small sales. However, as noted by the U.S. Court of Appeals and the General Accounting Office, maximizing bonus bids per acre and assuring receipt of fair market value are different concepts. As is pointed out in Appendix K, the MMS bid adequacy procedures focus Government evaluations on tracts with fewer bids in order to provide added assurances for achieving fair market value.

Large sales tend to offer many lower value tracts (e.g., those in deeper water or containing smaller prospects) along with the few potentially high value prospects that tend to be offered in smaller sales. Average bid statistics reflect these differences and show a decline as areawide and focused sales have proceeded, particularly in the Gulf of Mexico where a sizeable unleased inventory of good prospects (unleased acreage which is estimated to be profitable for lessees to acquire) had accumulated prior to the start of areawide sales. Declines in the average bid due to such effects should therefore not be viewed as an indication of failure to meet the fair market value requirement. Rather, they are the natural result of offering less attractive tracts and/or tracts which are more expensive to explore and develop, such as those in deeper water or where operations are remote or hazardous.

It also should be noted that the decline in average bids began in 1980. Decreases in oil price expectations since 1982 contributed to the decline in average bids evident in the 1982-86 period. Again, declines caused by such changes in the economic value of the tracts offered and bid upon are not indicative of a failure to receive fair market value but a response to changing economic and geologic information.

Minimum Bid Options

The current minimum bid policy--a basic approach of $150 per acre, subject to reconsideration based on experience--was adopted through Secretarial decisions of March 11, 1982, and May 4, 1982, and modified again in 1984 and 1985. Although the increase to $150 per acre was largely regarded as a means of helping to assure fair market value at a time when oil prices were more than twice what they are today, the minimum bid can also be seen as a tool for providing incentives for leasing. In general, the higher the minimum bid, the later will be the leasing and exploration on higher cost, higher risk prospects. Thus, the level of the minimum bid can promote or retard exploration. (See Appendix F, Part V and Appendix K.)

Option C.1.a. would maintain the basic approach of a minimum bid of $150/acre but allow you to determine on a sale-by-sale basis what changes, if any, are to be made. The recent Call for Information and Nominations on Sale 96, North Atlantic (which anticipated use of a $25/acre minimum bid), is representative of the flexibility which this option provides. In addition, the final Notice of Sale for Sale 110, Central Gulf of Mexico, announced a return to the $25/acre minimum bid for deepwater blocks in that sale.

Bid Adequacy Review Procedures Options

In the opinion on the 1982 program, California v. Watt (II), the court found that it was reasonable for the Secretary to combine reliance on the competitive bidding process with the current tract evaluation and bid rejection procedures in order to satisfy the fair market value principle in section 18(a)(4) of the OCS Lands Act. These procedures are described in Appendix K.

Option C.2.a. maintains current bid adequacy review procedures and allows you to determine on a sale-by-sale basis what changes, if any, are to be made.

PROPOSALS FOR OCS LEASING OFFSHORE CALIFORNIA BEYOND THE CONTEXT OF THE SIZE, TIMING, AND LOCATION OF SALES THROUGH MID-1992

Your issuance of the Draft Proposed Final Program for OCS leasing offshore California was based on a consideration of proposals specified by P.L. 99-591. While the amalgamated proposal which you identified in February 1987 has been added to the attached decision sheets, those other proposals still appear there as well.

A first category of options concerns subarea deferrals. Table 17.3 and Appendix R of the SID describe the effect which these subarea deferral proposals would have on the estimated value of resources projected to be leased during the 5-Year Program and thereafter.

A second category of options concerns stipulations suggested by Governor Deukmejian for adoption as part of the 5-year program and by Congressmen Regula and Panetta for adoption until the year 2000. These stipulations would be applicable to all sales offshore California but are not intended to rule out additional sale-specific stipulations which may be recommended during the presale process for each sale.

A third category of options presents the phased leasing and development proposals of Congressmen Regula and Panetta. The Regula proposal would add a provision to allow alternate leasing in the northern and southern sectors of two military operating areas and would limit the number of leases which may be held for exploration to 250 at any one time. The former constraint parallels similar agreements with the Department of Defense and was made part of the February 1987 amalgamated proposal. The latter constraint would likely have little adverse effect on exploration offshore California.

Panetta's phasing proposal is far more constraining. Relative to the over 700 blocks offshore California which are generally of interest to industry, the Panetta proposal limits lease offerings through 1999 to only 173 blocks which are further offshore and in deeper water. Of these 173 blocks, only 50 could be offered in the 5-year program for the period mid-1987 to mid-1992, 50 in the next 5-year period, and the balance, 73 blocks, thereafter.

The fourth and fifth option categories address the slant (directional) drilling and litigation protection provisions of the Regula proposal. The directional drilling concept would permit a lessee to drill directionally into unleased Federal OCS areas. It would require changes in the OCSLA and regulations.

The litigation protection provision is very limited. It would exempt the scheduling of sales offshore California from the requirements of section 18 and prevent a challenge of the 5-year leasing program for offshore areas other than California on the basis of any decision relating to sales offshore California. The litigation protection, however, would not extend to challenges to individual sales.

SUMMARY OF OPTIONS FOR DECISION

Section 18 requires you to select a Proposed Final Program, including a configuration of planning areas, a leasing schedule, and a presale process for defining the size of sales. The options for your selection of a Proposed Final Program for the Nation as a whole and alternatives developed under P.L. 99-190 and P.L. 99-591 for leasing offshore California are listed on the attached two decision sheets. These sheets list those options concerning the size, timing, and location of sales for the period mid-1987 through mid-1992 and those concerning other proposals including leasing beyond mid-1992.

Your selection of a Proposed Final Program will be sent to the Congress and the President for a 60-day waiting period along with responses to specific recommendations of the Attorney General, a State or local government, and specific portions of the proposals for leasing offshore California specified by P.L. 99-591. After the 60-day period, you can give final approval to the new program.

Attachments:

1) Two decision sheets: one for 5-year program elements specified by section 18 of the OCSLA; and one for decision options which go beyond those elements;
2) Three alternative leasing schedules;
3) Maps of the proposed OCS planning areas;
4) The Proposed Final Program Secretarial Issue Document (SID), Appendices, and Subarea Attachment; and
5) A summary of comments on the February 1987 Draft Proposed Final Program for OCS leasing offshore California.

Decision

Proposed Final 5-Year Outer Continental Shelf Oil and Gas Leasing Program for Mid-1987 through Mid-1992

A.1. Planning Area and Subarea Options:

a. Adopt a modification of the configuration of planning areas, boundaries, and subarea deferrals adopted for the Proposed Program. (This option is subject to modification by the selection of suboption b, c, d, e, f, g, or h below.) ______

b. Defer leasing in any or all of the following subareas identified in Alternative 2 of the final EIS:

i. The subareas highlighted for further analysis and comments in the Proposed Program, revised as indicated by underlining:

(A) Three subareas extending 15 nautical miles (n. mi.) offshore, or, where further offshore, to the limit of low hydrocarbon potential as estimated by MMS in the North, South, and Mid-Atlantic planning areas ______

(B) The Gulf of Maine, north of 42°30' N. latitude (Note: this area is included in (A), above, as revised) ______

(C) The National Aeronautics and Space Administration (NASA) Flight Clearance Zone offshore Cape Canaveral (extending to 195 n. mi. offshore, south of 31° N. latitude) ______

(D) A subarea extending between 20 and 30 n. mi. offshore the Florida Gulf Coast from Apalachicola to State waters north of the Keys at approximately 82° W. longitude, adding to it 15 blocks in the "Gainesville" official protraction diagram (OPD) and removing from it 6 blocks in the "Pulley Ridge" OPD ______

(E) Four subareas seaward of approximately the westernmost continuous 1,000 meter isobath in the Washington-Oregon, Northern California, Central California, and Southern California planning areas ______

* Any revision of the 13 subareas highlighted for further analysis and comment in the February 1986 Proposed Program is underlined.

(F) Two subareas totaling 210 blocks adjacent to Unimak Pass in the St. George Basin and the North Aleutian Basin planning areas offshore Alaska ______

(G) A subarea of 59 blocks offshore Point Barrow, Alaska, in OPD NR 4-2 ______

ii. The congressional moratorium area in the North Atlantic ______

iii. Looe Key National Marine Sanctuary off Florida ______

iv. Key Largo National Marine Sanctuary off Florida ______

v. A subarea from Apalachicola to Panama City, Florida ______

vi. A subarea 20-30 n. mi. offshore in the Dry Tortugas OPD, off Florida ______

vii. A subarea about 10.5 n. mi. (12 statute miles) offshore the Yukon Delta in the Norton Basin (101 blocks) ______

c. Defer subareas per the California Governor's Proposal of 5/7/86 ______

d. Defer subareas per the Regula Proposal re: offshore California (through mid-1992) ______

e. Defer subareas per the Panetta Proposal re: offshore California (through mid-1992) ______

f. Defer subareas per the Institute for Resource Management Bering Sea proposal of 5/8/86 ______

g. Defer subareas per the Draft Proposed Final Program amalgamated proposal for the OCS offshore California ______

h. Highlight some or all of the subareas considered for deferral at the 5-year program stage for consideration during the presale process ______

i. Other ______

A.2. Leasing Schedule Options:

a. Adopt the Proposed Final Program base schedule of standard sales, updated to cover mid-1987 through mid-1992. (This option is subject to modification by the selection of suboption b, c, d, e, f, g, or h, below.) _____

b. Add a single sale in the Straits of Florida in 1992 (south of 25°07' N. latitude) _____

c. Defer leasing in any or all of the following six planning areas:

   i. North Atlantic _____
   ii. Southern California _____
   iii. Central California _____
   iv. Northern California _____
   v. Washington-Oregon _____
   vi. North Aleutian Basin _____
   vii. All six areas _____

d. Schedule biennial sales in any or all of eight areas with higher value and/or higher interest:

   i. Southern California _____
   ii. Central California _____
   iii. Northern California _____
   iv. Eastern Gulf of Mexico _____
   v. Beaufort Sea _____
   vi. Navarin Basin _____
   vii. North Aleutian Basin _____
   viii. St. George Basin _____
   ix. All eight areas _____

e. Designate Frontier Exploration Sales as follows:

   i. Confirm designation of the following sales as frontier exploration sales:

      (A) Gulf of Alaska--Sale 114 _____
      (B) Kodiak--Sale 127 _____
      (C) Cook Inlet--Sale 136 _____
      (D) Hope Basin--Sale 133 _____
      (E) Shumagin--Sale 129 _____
      (F) North Atlantic--Sale 134 _____
      (G) Mid-Atlantic--Sale 121 _____
      (H) South Atlantic--Sale 108 _____
      (I) Washington-Oregon--Sale 132 _____
      (J) All nine sales _____

ii. Add frontier exploration sale designation to all sales in either or both of the following areas:

(A) St. George Basin ______
(B) Norton Basin ______

f. Hold supplemental sales:

i. Adopt annual sales of blocks outside of the Central and Western Gulf of Mexico: rejected and forfeited bid blocks offered in a prior period; and development blocks. ______

ii. Extend the supplemental sale concept to offer all unleased blocks on the same structure as the blocks offered. ______

g. Adopt the schedule for Options A.2.a and A.2.e, revised to delete Sale 127, Kodiak; delay Sale 119, Central California, until 1990; delay Sale 132, Washington-Oregon until 1992; and schedule a combined Gulf of Alaska/Cook Inlet sale in 1991. ______

h. Other ______

B.1. Size/Presale Process Options:

a. Focus on Promising Acreage

i. Confirm the presale approach of focusing on promising acreage--early resolution of conflicts concerning areas of high environmental concern and low resource potential or industry interest including:

(A) Larger offerings in the Gulf of Mexico, smaller offerings in most other areas. ______

(B) Delay deferrals until after the sale-specific draft EIS ______

(C) Revise nomination procedures so as to request more detailed information from industry on areas of interest prior to the issuance of the Call (to be displayed in the Call) and again after the issuance of the draft EIS; but do not require additional proprietary data or, if required, exempt it from release. ______

(D) Revise nomination procedures so as:

(I) to request more detailed information concerning "negative nominations"; and/or ______

(II) to develop minimum criteria for the consideration of deferral requests. ______

(E) A sale-by-sale decision on whether to publish a pre-Call notice in the Federal Register soliciting industry comments on whether there should be any deferral of leasing based on resource potential or interest in portions of the planning area or any delay of the sale, provided that any proprietary information will be held confidential by the MMS throughout the 5-year period covered by the new program. ______

(F) Flexible Call for Information: identify a relatively narrow Call area; accept acreage nominations outside of the Call area, if any, and include that acreage at the Area Identification stage; request public comments on any acreage nominated outside the original Call area, and require that comments opposed to the addition of such additional acreage be accompanied by adequate scientific justification; consider all relevant scientific evidence during the preparation of the EIS along with a proper assessment of the benefits of leasing that acreage. ______

(G) Highlight on a map issued with the Call the MMS interpretation of the promising acreage area within the Call area. The text of the Call would explain that while primary consideration would be given to the highlighted area, respondents may nominate any acreage within the Call area. Comments would be requested within the entire Call area. Such nominations and comments would be considered at the Area Identification stage for identification of the proposal to be analyzed in the EIS. ______

(H) Other ______

b. Tract Selection Sales

i. Hold sales based on tract-specific nominations generally offering up to 2 million acres. ______

ii. Hold sales based on tract-specific nominations with actual acreage offered dependent on the magnitude of nominations, hydrocarbon potential, and environmental and multiple-use considerations. ______

c. Hold Areawide Sales. For the purpose of this option, "areawide sales" has the meaning of the initial areawide approach described in the Proposed Final Program Secretarial Issue Document. ______

d. Other ______

C.1. Minimum Bid Options:

a. Confirm the Proposed Program decision to maintain the $150/acre minimum bid as the basic approach and determine on a sale-by-sale basis what changes, if any, are to be made. ______

b. Other ______

C.2. Bid Adequacy Review Options:

a. Confirm the Proposed Program decision to maintain current bid adequacy review procedures as the basic approach and determine on a sale-by-sale basis what changes, if any, are to be made. ______

b. Other ______

______________________________ ______
Secretary of the Interior Date

Decision

OCS Leasing Activity Beyond the Size,
Timing, and Location of Sales and Beyond Mid-1992

1. Subarea deferrals offshore California beyond mid-1992:

   a. Regula Proposal ______

   b. Panetta Proposal ______

   c. Other ______

2. Adopt stipulations for leases to be awarded

   a. California Governor's Proposal re: sales offshore California through mid-1992 (all stipulations) ______

      i. Air quality ______
      ii. Oil spills ______
      iii. Transportation (pipeline) ______
      iv. Onshore facilities ______
      v. Fisheries ______
      vi. Biological resources ______
      vii. Important biological resources ______
      viii. Marine biota ______
      ix. Oil processing ______
      x. Cultural resources ______
      xi. Operations controls ______
      xii. Hold harmless ______
      xiii. Hazardous dumpsites ______
      xiv. Navigation safety ______
      xv. Water use ______
      xvi. Timing of operations ______
      xvii. Protection of military areas ______
      xviii. Discharges ______

   b. Regula Proposal re: sales offshore California through 2000 (all stipulations) ______

      i. Air quality ______
      ii. Oil spills ______
      iii. Transportation (pipeline) ______
      iv. Onshore facilities ______

   c. Panetta Proposal re: sales offshore California through 2000 (all stipulations) ______

      i. Air quality ______
      ii. Oil spills ______
      iii. Transportation (pipeline) ______
      iv. Onshore facilities ______
      v. Fisheries/biological resources ______
      vi. Discharges ______

d. Other: Highlight all of the above proposed stipulations for consideration during the presale process for sales in California OCS areas* ______

3. Phased Leasing and/or Development offshore California through 2000

a. Regula Proposal ______

b. Panetta Proposal ______

c. Other ______

4. Slant Drilling offshore California

a. Regula Proposal ______

b. Other ______

5. Limited Litigation Protection for Setting the Size, Timing, and Location of All Sales through 2000

a. Regula Proposal ______

b. Other ______

*Also, indicate that it is our intention to include similar levels of protection to those recommended in Governor Deukmejian's proposal in individual leases at the time of the sale, but it is premature to settle upon specific language or its applicability for a variety of reasons, including OCS Lands Act consultation considerations.

______________________________ ______
Secretary of the Interior Date

PROPOSED FINAL 5-YEAR OCS OIL AND GAS LEASING PROGRAM
FOR MID-1987 THROUGH MID-1992
SECRETARIAL ISSUE DOCUMENT

April 1987

CONTENTS

FIGURES



TABLES

MAPS



APPENDICES

## Executive Summary

This revised Secretarial Issue Document (SID) provides the basis for the decisions by the Secretary of the Interior (Secretary) that will structure a Proposed Final 5-Year Outer Continental Shelf (OCS) Oil and Gas Leasing Program beginning in 1987.

Under the requirements of section 18 of the OCS Lands Act (the Act), as they have been interpreted by rulings of the U.S. Court of Appeals for the District of Columbia Circuit, the Secretary must prepare and maintain an oil and gas leasing program which ". . . shall consist of a schedule of proposed lease sales indicating, as precisely as possible, the size, timing, and location of leasing activity which he determines will best meet national energy needs for the five-year period following its approval . . . ." As explained by the court,

> . . . The 1978 amendments [to the Act] outlined a five step process for achieving . . . expeditious but orderly development [of the OCS]. The first step is the adoption of a five-year leasing program which contains a proposed schedule of lease sales. This is followed by sale of the leases, exploration, development and production, and ultimately, sale of the recovered minerals. The five step process is "pyramidic in structure, proceeding from broad-based planning to an increasingly narrower focus as actual development grows more imminent." Additional study and consideration is required before each succeeding step is taken. Thus, while an area excluded from the leasing program cannot be leased, explored, or developed, an area included in the program may be excluded at a later stage.*

In preparing a new program, the Secretary must consider a variety of factors bearing on the costs and benefits of leasing OCS oil and gas. The Secretary must then develop a schedule of lease sales which will "best meet national energy needs," balancing the potential benefits of the discovery of oil and gas against the potential costs.

The development of the Proposed Final Program is the third stage in the process of formulating the new 5-Year OCS Leasing Program. Review copies of the first stage--the Draft Proposed Program--were issued to the Governors of coastal States, affected Federal Agencies, and the public in March 1985. The second stage--the Proposed Program--was submitted to those same parties (including the Attorney General) and to Congress in February 1986. The Proposed Final Program is scheduled for transmittal to the President and Congress in early 1987. Final approval by the Secretary is permitted by the Act 60 days thereafter.

A draft environmental impact statement (EIS) was issued with the Proposed Program. The final EIS will be issued prior to the decision on the Proposed Final Program.

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*California v. Watt 712 F.2d 588 (D.C. Cir. 1983) (hereafter, California v. Watt (II)), decided July 5, 1983.

This SID with its appendices serves a number of functions:

1. It provides information on the various factors which the Secretary is required to consider, and it documents the sources and methods used in developing the new program.

2. It develops a framework and guidelines for balancing costs and benefits, recognizing the inherent limitations in the information about them such as estimates of future conditions in the world oil market.

3. It sets forth options from which choices can be made concerning the size, timing, and location of lease sales in the Proposed Final Program and assurance of the receipt of fair market value.

The SID for the Proposed Final Program has a number of new features which distinguish it from the SID for the Proposed Program: it covers sales beginning in mid-1987; it provides additional ranges and sensitivity tests for a variety of quantitative measures; it contains final analyses of benefits and costs; it summarizes and responds to comments on the Proposed Program; it presents an estimate of the net social value of schedule options; it provides estimates of appropriations and staff pursuant to section 18(b); it contains new decision options; and it contains new quantitative analyses of the amalgamated proposal identified by the Secretary in the February 1987 Draft Proposed Final Program for the OCS offshore California.

Pursuant to P.L. 99-591, the programmatic EIS provides a resource and environmental analysis of the three separate proposals of the California Governor, Congressman Regula, and Congressman Panetta. Those proposals are also analyzed in this SID insofar as they relate to the size, timing, and location of leasing over the period of the new 5-year program--for example, the subarea deferral proposals affecting the period mid-1987 through mid-1992. However, certain aspects of these proposals either pertain to time periods following the 5-year program for mid-1987 through mid-1992 or address issues beyond the program elements specified by section 18--the size, timing, and location of sales. For example, the proposals of Governor Deukmejian and Congressmen Regula and Panetta provide for the adoption of stipulations for leases offshore California at the 5-year program stage. These stipulation proposals are analyzed in the EIS and in a separate California Analysis document designed to summarize the analysis for congressional review pursuant to P.L. 99-591. These stipulation proposals, however, are not analyzed in this 5-year program SID because stipulations are beyond the scope of the size, timing, and location of sales to which section 18 requirements apply and because this approach provides for a section 18 analysis of all OCS areas on a comparable basis in this SID.

Somewhat similarly, the subarea deferral element of the Institute for Resource Management (IRM) Bering Sea proposal is analyzed in this SID; however, the IRM proposal for a committee to recommend stipulations on the basis of specified principles is discussed only in general terms.

# I. Introduction

## A. Background

### I.A.1. History

The 5-Year OCS Oil and Gas Leasing Program for mid-1987 through mid-1992 is the third program to be developed under section 18 of the OCS Lands Act, as amended (43 U.S.C. 1344). Prior to the OCS Lands Act Amendments of 1978, which added section 18 in its entirety, OCS leasing programs had been issued as a discretionary act of the Secretary of the Interior (hereafter, the Secretary). Regulations implementing section 18 appear at 30 CFR 256.14-20.

The first program prepared under section 18 received final approval in June 1980. That program scheduled 36 sales in 16 OCS planning areas for the period September 1980 through June 1985. Those sales were to be held using the "tract selection" approach which offered a limited amount of acreage, as described in Part III.B and Appendix P. Sales held under that leasing program resulted in the leasing of more than 2 million acres in 1981, the first year in which the 2 million acre level was surpassed since the announcement of the goal of leasing 10 million acres per year in 1974. Bonus bid levels of nearly $5,000 per acre on some tracts in 1981 provided strong signals that there were many good prospects for investment in exploration for oil and gas in the Government's inventory of unleased tracts.

The 1980 program was challenged in the U.S. Court of Appeals for the District of Columbia Circuit (hereafter, the court). /1 In its 1981 decision, the court found fault with certain parts of the analysis performed for that program, but the court allowed leasing to continue and gave guidance for the formulation of the second program, then under development. The Secretary's compliance with the court's guidance was set forth in a SID and a set of appendices dated March 1982.

In July 1982, the second 5-year program developed under section 18 was given final approval by the Secretary. This program, currently in effect, scheduled 41 sales in 18 OCS planning areas between August 1982 and June 1987. Of those 41 sales, virtually all sales to be held after April 1983 were to use a new "areawide" approach to offer much more acreage, as described below in Part III.B and Appendix P.

The 1982 leasing program was also challenged in court. In a July 1983 opinion, the court upheld the 1982-1987 program formulation as having fully complied with the Act and the guidance it had set forth in its 1981 opinion. /2 Appendix A contains a discussion of the compliance of the development of this new 5-year program with section 18 as interpreted by the court.

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/1 California v. Watt, 668 F.2d 1290 (D.C. Cir. 1981) (hereafter, California v. Watt (I)), decided October 6, 1981.

/2 California v. Watt (II) at 611.

## I.A.2. Development of the New Program

The initiation of development of the new program was announced in letters to the Governors of coastal States and to interested Federal Agencies, dated July 5, 1984, and in a Federal Register Notice published on July 11, 1984 (49 FR 28332). The Secretary's selection of a Draft Proposed Program was announced in letters to the Governors of coastal States and to interested Federal Agencies dated March 19, 1985, and in a Federal Register Notice published on March 22, 1985 (50 FR 11585).

### The Draft Proposed Program (March 1985)

The basic features of the Draft Proposed Program were as follows:

1. Planning Area Boundaries for the Draft Proposed Program

Chief among the planning area boundary changes made by the Draft Proposed Program were its revision of the July 1984 description by establishing outer boundaries for planning areas; reconfiguring the OCS from 24 to 26 planning areas by dividing the South Atlantic into two areas (South Atlantic and Straits of Florida) to allow a more concentrated review of those areas under the provisions of section 18; and reconfiguring the planning areas offshore California from two to three to allow a more concentrated section 18 review of those areas as well as to respond to public comments.

2. The Leasing Schedule for the Draft Proposed Program

Over the period mid-1986 through mid-1991, the Draft Proposed Program provided for 33 standard sales, 5 frontier exploration sales, and 5 supplemental sales.

This contrasts with the current program (as approved in July 1982), which provided for 40 standard sales and 1 reoffering sale. The new draft schedule proposes the continuation of annual sales in the two highest-value, highest-interest areas: the Central and Western Gulf of Mexico. The Draft Proposed Program scheduled triennial sales in 15 other areas and thus slowed the pace of leasing in contrast with the biennial pace in the current 5-year program.

The first OCS sale for the area offshore Washington and Oregon since 1964 was proposed for 1991, given the value of that area's resources and industry interest. The schedule also proposed the first sale in Hope Basin, offshore Alaska, also in 1991. /1 The sales for these areas were proposed late in the 5-year period to allow time for the necessary environmental studies to be performed.

a. The Base Schedule

The base schedule proposed 33 standard sales in 17 planning areas. Eleven of those sales were sales carried over from the current to the new program.

b. Frontier Exploration Sales Offshore Alaska

Five frontier exploration sales were proposed offshore Alaska to increase the flexibility of the schedule to respond to possible future changes in prices

/1 The June 1980 program had proposed a sale in Hope Basin in May 1985.

and other economic conditions or improved geologic and geophysical data. These five sales were proposed for the Gulf of Alaska, Cook Inlet, Shumagin, Hope Basin, and Kodiak.

These frontier exploration sales would include an additional presale step: a Request for Interest scheduled for 4 months prior to the Call for Information and Nominations. Responses to each Request would be used to help determine whether the approximately 2-year sale process should proceed in those areas. The scheduling of these sales was designed to provide for flexibility in the program. Under current conditions, and if these sales were to be held this year, the Department would not necessarily regard sales in these areas as viable. Yet conditions could change so that having the option to initiate and hold these sales could be in the Nation's interest. The annual review of the program under section 18(e) will also be used to determine whether to proceed with these sales.

c. Supplemental Sales

The schedule also included an annual sale for a small number of selected blocks in areas other than the Central and Western Gulf of Mexico: drainage and development blocks; and blocks on which bids were rejected in the preceding year. These sales would provide for: (1) The expeditious offering of blocks in which serious industry interest can reasonably be anticipated; (2) orderly development of OCS resources (increasing the potential for actual development and reducing the time necessary to bring new fields into production); and (3) reduction of costs of delay. These blocks would only be offered after compliance with the requirements of the National Environmental Policy Act, the OCS Lands Act, and other applicable statutes. The environmental assessment documentation for each of these sales would be released at approximately the same time as the Proposed Notice of Sale. If it is determined that an EIS is required for one of these sales, revised presale milestones would be issued.

d. Areas in Which No Sales Were Proposed in the Draft Proposed Program

The schedule proposed no sales in St. Matthew-Hall, Aleutian Arc, Aleutian Basin, and Bowers Basin so as to concentrate management resources on other areas with higher resource potential and industry interest. No sale was scheduled for the Straits of Florida since this area was not yet analyzed as a separate planning area.

e. Acceleration (Flexibility) Provision

The Draft Proposed Program included a provision to accelerate sales from triennial to biennial offerings in eight areas of higher value and/or higher interest (but not so as to increase the total number of sales in any planning area in the approved program). The areas where such acceleration was to be considered included: Southern California; Eastern Gulf of Mexico; Central California; Northern California; Navarin Basin; Beaufort Sea; North Aleutian Basin; and St. George Basin. Specific guidelines for the implementation of the acceleration provision were to be developed for the Proposed Program.

3. Size of Lease Sales in the Draft Proposed Program

It was proposed that the size of lease sales be determined by a presale process which results in focusing on promising acreage. Promising acreage is that which is reasonably determined to be likely to lead to exploration and/or development of oil and gas resources. That determination would be made by means of a consultative process which will provide for the early resolution of conflicts based on information and nominations obtained from affected Federal Agencies, State and local governments, the public, and potential bidders, as well as Minerals Management Service analysis. Where strong environmental or other conflicts exist the focusing on promising acreage concept provides that these issues be addressed early so that, depending on the merits of each case, deferral of areas can be considered.

The offering of promising acreage was designed to give effect to DOI's desire to make available for lease areas of hydrocarbon potential as identified by industry and MMS, while remaining cognizant of the particular circumstances relevant to each sale. The various OCS areas and the adjacent onshore regions vary significantly in terms of exploration and development history, onshore support capability, and possible multiple-use conflicts. In preparing for leasing activity, regional differences would be taken into account on a case-by-case, sale-by-sale basis, with the emphasis on consultation, and, wherever possible, consensus.

4. Assurance of Receipt of Fair Market Value in the Draft Proposed Program

Section 18(a)(4) provides that leasing activities are to be conducted so as to assure receipt of fair market value for lands leased and rights conveyed. The policy option selected for the Draft Proposed Program maintained current procedures for assuring the receipt of fair market value. The option selected also provided for a review of the question of whether the minimum bid level should be changed either in general or on a variable basis for different planning areas.

The Proposed Program (February 1986)

Based on a consideration of comments on the Draft Proposed Program and a revised section 18 analysis, the Secretary issued a Proposed Program.

The Proposed Program was announced to the Governors of coastal States and to interested Federal Agencies in letters dated February 4, 1986, and in a Federal Register Notice published on February 7, 1986 (51 FR 4816). The Proposed Program retained a number of features of the Draft Proposed Program, but modified others.

The Proposed Program schedule contained sales in 21 of the 26 OCS planning areas for the period 1987-1991: 27 standard sales; 10 frontier exploration sales (the same 5 as in Draft Proposed Program [Kodiak, Gulf of Alaska, Hope Basin, Cook Inlet, Shumagin] plus the addition of this designation for sales in the Washington-Oregon, and North, South, and Mid-Atlantic areas); and 5 small supplemental sales. The Draft Proposed Program acceleration provision was retained and a variety of criteria for its implementation were proposed. Based on a consideration of comments, 15 subareas were proposed for deferral from the new program and 13 others were highlighted for further analysis and comments. The presale process continued to be specified as focusing on promising acreage, emphasizing consultation with coastal States and other affected parties with a view to the early resolution of conflicts. Fair market value provisions remained the same, except that sale-by-sale reconsideration of the minimum bid was specified.

The Draft Proposed Final Program for the OCS Offshore California (February 1987)

Pursuant to P.L. 99-591, on February 2, 1987, the Secretary issued the Draft Proposed Final Oil and Gas Leasing Program for the (OCS) offshore California. The Draft Proposed Final Program covered the 5-year period from mid-1987 through mid-1992 and included the following key features:

SIZE OF SALES--THE PRESALE PROCESS

The proposed presale process was referred to as "focusing on promising acreage." In the case of OCS sales offshore California, the focus will reflect the geologic character of the OCS offshore California and the results of the extensive OCS consultation process. The amount of acreage actually offered for lease offshore California will be restricted not only for environmental reasons but also because of other ocean uses, including military operations offshore. A phased leasing provision concerning the Camp Pendleton Amphibious Assault Area and the Encinitas Naval Electronics Testing Area was incorporated into the Draft Proposed Final Program. Each of those areas would be divided into two sectors; active leases would be allowed in only one sector of each at any one time. Only one of two tracts nearest shore in a sector could be leased at one time for the Encinitas area.

SCHEDULE OF SALES

The acceleration provision of the Proposed Program was dropped. This provision contemplated a return from the 3-year cycle of sales to a 2-year cycle, if activated.

The Draft Proposed Final Program proposed five standard sales at a triennial pace: 1989 and 1992 sales were proposed for the Northern and Southern California planning areas; and a 1990 sale was proposed offshore Central California.

Tentatively scheduled to be held in late 1988, the first annual supplemental sale would offer a small number of blocks from any planning area other than the Central and Western Gulf of Mexico. Rejected and forfeited bid blocks and development blocks (including those susceptible to drainage) could be considered for offering. Consideration for offering could be given to blocks on which bids were rejected or forfeited during the preceding fiscal year. Should an annual supplemental sale not occur for any reason, a subsequent supplemental sale might include rejected and forfeited bid blocks which could have been included in the sale not held. The development of a modification of existing Interior regulations governing OCS sales for the implementation of supplemental sales was announced.

PROPOSED SUBAREA DEFERRALS

The proposed deferrals in the Draft Proposed Final Program included deep water areas generally beyond the 900 meter isobath in all three California OCS planning areas and, in addition, the following areas:

Northern California

°Coastal buffers offshore the Redwoods National Park Area of Special Biological Significance (ASBS), Trinidad Head ASBS, Kings Range National Conservation Area (the area offshore Cape Mendocino/Punta Gorda), and the Pygmy Forest Ecological Staircase

Central California

°A coastal buffer offshore the Kelp Beds at Saunders Reef ASBS, the Del Mar Ecological Reserve, and Gerstle Cove ASBS
°The area offshore Point Reyes, the Point Reyes - Farallon Islands National Marine Sanctuary, offshore San Francisco Bay, and the immediate vicinity of Cordell Bank
°A coastal buffer offshore the James V. Fitzgerald Marine Reserve
°A coastal buffer offshore Point Ano Nuevo Point and Island ASBS and overlapping the northern portion of the Sea Otter Range
°The large area offshore Monterey Bay and Big Sur
°A coastal buffer south of the Big Sur proposed deferral, overlapping the southern portion of the Sea Otter Range and adjacent to the Mouth of Salton Creek ASBS

Southern California

°The Santa Barbara Federal Ecological Preserve and Buffer Zone
°The Channel Islands National Marine Sanctuary
°The area offshore Santa Monica from Point Dume to Point Fermin
°A coastal buffer offshore Newport Beach and Irvine Coast Marine Life Refuges and Heisler Park ASBS
°A coastal buffer offshore San Diego Marine Life Refuge and San Diego-La Jolla Ecological Reserve ASBS
°The area offshore San Diego; and the San Nicolas Basin Navy Operating Area

FAIR MARKET VALUE

The fair market value element of the program would confirm the decision announced in the Proposed Program. The minimum bid would remain $150/acre as the basic approach subject to reconsideration on a sale-by-sale basis. Likewise, current bid acceptance criteria (as dicussed in Appendix K of the Secretarial Issue Document) would be retained as the basic approach, subject to sale-by-sale reconsideration

STIPULATIONS

Interior announced the intention to include levels of protection similar to those recommended in Governor Deukmejian's proposal in individual leases at the time of the sale. The Draft Proposed Final Program highlighted all proposed stipulations for consideration during the sale-specific consultation process (in particular, the EIS scoping process pursuant to the National Environmental Policy Act and the consultations with the Governor at the time of issuance of the Proposed Notice of Sale required by section 19 of the OCS Lands Act) for OCS sales offshore California.

New Features of the SID for the Proposed Final Program

The new 5-year program is now planned to cover the period mid-1987 through mid-1992. The Proposed Program covered the period 1987 through 1991. The period covered by the new program has moved by 6 months because of various administrative considerations, including additional time allotted for the study of subareas which are potential candidates for deferral from the new program and timing of the release of the Proposed Final Program so that Congress would be in session during the 60-day congressional notification period. The assumptions of the section 18 analyses have been made consistent with the new period to be covered by the program.

The SID for the Proposed Program contained updated and revised analyses required by section 18. In response to the DOI's February 1986 request for comments, many commenters provided helpful comments and criticism of the analysis. This SID contains the final version of those analyses and decision options. The final section 18 analyses and the final EIS will be a part of the decision materials for the Proposed Final Program.

The Proposed Final Program will contain a schedule of proposed lease sales "indicating, as precisely as possible, the size, timing, and location of leasing activity" and program policies selected by the Secretary. The schedule will indicate the proposed timing of presale steps for sales to be held beyond the current schedule. Sales will continue to be held in accordance with the current schedule until the new program receives final approval.

The Consultation Process

An extensive consultation process for the development of the new program is prescribed by the OCS Lands Act. Under section 18(d)(2) of the OCS Lands Act and 30 CFR 256, the Proposed Final Program and the analyses on which it is based will be transmitted to the President and the Congress. Copies of or citations for all Federal Register Notices requesting comments on the new program appear in Appendix M.

Comments were received from Governors, State and Federal Agencies, State legislators, local government entities, oil and gas industry members and associations, and from the general public. Responses are briefly summarized below and all are detailed in Appendix B of this SID. Summaries of comments relevant to decision options also appear in Part III of this SID.

Development of the new program has also been the subject of consultation under the auspices of the OCS Advisory Board's Policy Committee, pursuant to regulations at 30 CFR 256.19. Development of the new 5-year program was discussed at meetings of the Policy Committee on April 10-11, 1985, November 6-7, 1985, March 12-13, 1986, and October 29-30, 1986.

Nine public hearings held pursuant to the National Environmental Policy Act are described in the EIS.

Furthermore, development of the new program has been the subject of testimony before the House Merchant Marine and Fisheries Subcommittee on the Panama Canal/OCS on April 3, 1985, by Secretary Hodel and on May 13, 1986, by MMS Director Bettenberg.

The development of the new program has also overlapped with discussions mandated by Public Law 99-190 "...to resolve the outstanding conflicts with respect to the future leasing and protection of lands on the California outer continental shelf for oil and gas exploration and development." Bimonthly reports to Congress summarized the progress of those discussions. The relevant requirements of Public Law 99-591, which resulted from the consultation process, are set forth in detail in the California Analysis document.

Comments on the February 1987 Draft Proposed Final Program for the OCS offshore California are summarized in an attachment to the Decision Memorandum.

### I.A.3 General Summary of Comments on the Proposed Program

Over 3,400 comments were received on the Proposed Program, including some 1,500 received directly by the Department of the Interior and some 1,800 received as enclosures to letters from the Governors of California, Florida, North Carolina, Oregon, and Texas. The comments came from Federal Agencies; Governors of 20 coastal States; agencies and legislators of 9 coastal States; local governments in 4 coastal States; petroleum and related industries and associations; environmental and other interest organizations; members of Congress; and private citizens. These comments are summarized by topic in Appendix B and in Part III of this SID as they relate to decision options.

#### Overview of Comments

#### -Comments on Section 18(a)(2) Factors Exclusive of Industry Rankings

Respondents frequently cited potential impacts that could result from OCS development, including potential effects on navigation and shipping, especially off California; effects on environmentally sensitive areas; potential conflicts with other uses of the sea and seabed including military uses; and potential fishing conflicts. Governors commented on onshore impacts on air quality, coastal infrastructure and the potential environmental and long-term economic impacts that could result from a disregard for equitable sharing. The States also expressed concern over potential conflicts with local coastal management plans. The biological significance and productivity of fisheries and their role in the Nation's food supply were identified as possible conflicts. Coastal tourism and recreation were cited as concerns by several States and local governments. Among the many concerns expressed in comments from environmental and other interest organizations, the following issues were most frequently cited: cumulative impacts; air quality; environmental sensitivity; deep water technology; public involvement; pace of leasing; fiscal impacts; other uses of the seabed and coasts; vessel traffic lanes; oil spill risks and response; effects of discharged drilling muds and cuttings and formation waters; infrastructure burdens; effects on coastal dependent economies; oil and gas transportation strategies; and effects on whales and other marine animals.

Numerous comments focused on the need for equitable sharing of developmental benefits and environmental risks. Louisiana commented that the 5-year program would place an even greater burden on the Gulf Coast, citing scheduling concessions to all areas of the country except the Central and Western Gulf of Mexico. The high risks of exploration and low hydrocarbon potential were frequently cited as reasons in support of removing California's north coast from leasing consideration. Local governments, especially in California, frequently commented that developmental benefits and environmental risks were inadequately considered in the Proposed Program.

With respect to relative marine productivity and environmental sensitivity, California, Georgia, and Massachusetts questioned specific assumptions on which the Proposed Program's analysis of these factors is based. Numerous State and local government agencies in California and several environmental organizations stated that the Proposed Program does not adequately consider the relative marine productivity and environmental sensitivity of planning areas.

With regard to oil and gas transportation networks and strategies, several commenters cited navigation concerns and shipping safety. The California Coastal Commission recommended that oil transportation by pipeline be required for all areas of the Pacific coast. Numerous local governments in California called for adequate consideration of navigation and sealanes. Ventura County recommended that navigational hazards posed by offshore platforms be addressed by stipulation in future lease sales. The City of Santa Barbara recommended deleting tracts located in Santa Barbara Channel shipping lanes from the leasing program. Where mentioned in comments, pipeline transportation was generally favored over tankers.

Most comments on the topic of relevant environmental and predictive information recommended continuation of the environmental studies program, and several specific suggestions were made regarding this program. Florida endorsed development of a 5-Year Environmental Studies Program Management Plan and requested that areas with ongoing studies needed for management decisions be deferred from the leasing program. Louisiana recommended that environmental studies be focused on areas of most promising acreage where sales are held more frequently. Oregon expressed concern that there is insufficient lead time to plan and execute necessary environmental studies before conducting a lease sale in the Washington-Oregon planning area. The National Oceanic and Atmospheric Administration made suggestions for aligning the 5-Year Environmental Studies Program Management Plan with the leasing schedule to ensure that sufficient data are acquired prior to the Request for Interest step for frontier exploration sales in Alaska OCS planning areas.

-Comments on Possible Changes to the Leasing Process

Many commenters expressed strong support for the Secretary's emphasis on consultation and consensus, the focusing on promising acreage concept, and the triennial pace of leasing in most areas outside the Central and Western Gulf of Mexico.

The presale process was the focus of numerous comments. The Governors of Maine, New Hampshire, Massachusetts, Rhode Island, Delaware, Maryland, Virginia, North Carolina, Florida, and California expressed general agreement with the proposed presale process. Texas and Alaska, several local governments, and most environmental organizations called for a return to a tract selection process. Industry continued to favor the areawide approach.

Comments on the presale process also addressed proposed modifications which would entail submitting more detailed industry interest information, submitting more detailed negative nomination information (i.e., information requesting deletion of an area from a sale), and announcing the proposed Call area in the Federal Register prior to issuance of a Call for Information and Nominations. Maine, Massachusetts, New Jersey, and North Carolina recommended that nomination procedures be revised to request more detailed information from industry concerning areas of interest. Industry commenters opposed such a revision, citing concerns about disclosure of proprietary data. Most industry commenters did endorse the proposal to revise negative nomination information requirements. Maine opposed this proposal. Maine and a majority of industry commenters also opposed announcement of the Call area before issuance of the Call for Information and Nominations. The American Petroleum Institute, National Ocean Industries Association, and Exxon suggested several modifications to the presale process, the most notable of which is a flexible Call for Information and Nominations which would allow nomination of areas outside the Call area.

The proposed means for pursuing flexibility in the leasing process drew numerous and various responses. The Environmental Protection Agency (EPA) and Maine, New Hampshire, Massachusetts, Rhode Island, Connecticut, New Jersey, Delaware, Maryland and North Carolina endorsed the addition of a Request for Interest as an early pre-sale step for frontier exploration sales. Oregon and Washington and several environmental organizations commented that frontier exploration sales would introduce uncertainty to the lease schedule contrary to the requirements of the OCS Lands Act, as amended. Chevron and Shell expressed some support for frontier exploration sales, and Exxon noted that the Request for Interest step for such sales might invite additional legal challenge.

Several commenters questioned the legal authority for scheduling supplemental sales and expressed concern about the environmental assessment process for such sales. EPA and Florida, California, and Alaska endorsed supplemental sales provided that pertinent regulations are promulgated and environmental safeguards are established. Connecticut, Alabama, and many industry commenters gave a general endorsement of supplemental sales. Several State and local government agencies and environmental organizations expressed opposition to this flexibility provision.

The majority of comments concerning the acceleration provision either flatly opposed the concept or questioned the adequacy of the criteria proposed to be considered as a basis for accelerating lease sales. Some respondents, including Conoco and Sun, expressed doubt that the acceleration provision would be an effective means for providing necessary flexibility to the 5-year leasing program.

-Commenters' Timing and Location Recommendations

Opinions on the size of sales as determined by the prelease process were divided. Areawide leasing was generally advocated by industry and opposed by others. Those opposed frequently called for a return to tract selection procedures. The concept of focusing on promising acreage was generally well received, but many commenters called for further definition and refinement of the process.

On the topic of location, EPA specifically recommended that leasing be deferred in the North Atlantic, Straits of Florida, and North Aleutian Basin planning areas. The Governor of Florida and several State and local government agencies expressed opposition to leasing in the Straits of Florida planning area. Gulf Coast States generally indicated that more sales should be held outside the Central and Western Gulf of Mexico.

The Governor of California agreed with the reconfiguration of planning areas offshore California, but recommended substantial additional subarea deferrals beyond those incorporated in the Proposed Program. California State agencies and local governments generally opposed leasing in the Central and Northern California planning areas. The City of Eureka, however, endorsed leasing in the Northern California planning area. Two congressional proposals calling for substantial subarea deferrals offshore California were submitted as a result of the negotiating process initiated under P.L. 99-190.

Industry stated general agreement with the location of proposed sales. Some industry commenters called for renewed emphasis on leasing in Alaska and California OCS regions, citing the potential for new resources that exists there. Citizen comments generally opposed leasing off California. Alaska recommended that leasing be deferred in the North Aleutian Basin planning area.

The triennial pace of leasing was generally viewed favorably. Exceptions included the following: Louisiana and Texas commented that slowing the pace of leasing outside the Central and Western Gulf of Mexico planning areas would result in an unbalanced program; Alabama stated that the pace of leasing outside the Central and Western Gulf is insufficient; and Massachusetts expressed reservations over the timing of sales in the North Atlantic planning area and stated that only one sale there during the 5-year period is warranted.

Certain California State and local government agencies commented that the reconfiguration, coupled with the introduction of supplemental sales, would accelerate, rather than slow, the pace in some areas. Several California respondents alleged there is no slowing of the sale pace, since the number of planning areas has been increased from 2 to 3. Numerous industry respondents expressed a preference for biennial leasing in most areas outside the Central and Western Gulf of Mexico. Alaska requested specific limits on the number of sales scheduled off the State's coast per year and during the 5-year period covered by the leasing program.

-<u>General and Miscellaneous Comments</u>

Topics most commonly addressed apart from section 18 considerations and those requested in the February 1986 <u>Federal Register</u> Notice included the following: expressions of support for OCS revenue sharing; calls for speedy and efficient implementation of 8(g) revenue distribution procedures; requests for reinstatement of a Congressional moratorium and negotiation of a long-term agreement to protect environmentally sensitive areas off California; the need for alternative energy strategies based on renewable energy sources and conservation; and concern for the onshore impacts on coastal-dependent economies. State and local governments suggested that OCS revenue be shared to fund their participation in the leasing program. Heavy citizen response (mostly from California) called for reinstatement of the moratorium off California. Local governments in California frequently called for a leasing moratorium unless a long-term agreement on the status of sensitive areas can be achieved. Elements of congressional proposals beyond the size, timing, and location of sales during mid-1987 through mid-1992 are discussed in the California Analysis document. The IRM Bering Sea proposal included not only a substantial subarea deferral element but also called for the creation of a Bering Sea Advisory Committee to recommend sale-specific stipulations in accordance with specified principles.

The following pages contain a copy of section 18 and a copy of maps depicting the 26 planning areas of the OCS pursuant to the decision on the Proposed Program.

Section 18 of the OCS Lands Act

"SEC. 18. OUTER CONTINENTAL SHELF LEASING PROGRAM.—(a) The Secretary, pursuant to procedures set forth in subsections (c) and (d) of this section, shall prepare and periodically revise, and maintain an oil and gas leasing program to implement the policies of this Act. The leasing program shall consist of a schedule of proposed lease sales indicating, as precisely as possible, the size, timing, and location of leasing activity which he determines will best meet national energy needs for the five-year period following its approval or reapproval. Such leasing program shall be prepared and maintained in a manner consistent with the following principles: 43 USC 1344.

"(1) Management of the outer Continental Shelf shall be conducted in a manner which considers economic, social, and environmental values of the renewable and nonrenewable resources contained in the outer Continental Shelf, and the potential impact of oil and gas exploration on other resource values of the outer Continental Shelf and the marine, coastal, and human environments.

"(2) Timing and location of exploration, development, and production of oil and gas among the oil- and gas-bearing physiographic regions of the outer Continental Shelf shall be based on a consideration of—

"(A) existing information concerning the geographical, geological, and ecological characteristics of such regions;

"(B) an equitable sharing of developmental benefits and environmental risks among the various regions;

"(C) the location of such regions with respect to, and the relative needs of, regional and national energy markets;

"(D) the location of such regions with respect to other uses of the sea and seabed, including fisheries, navigation, existing or proposed sealanes, potential sites of deepwater ports, and other anticipated uses of the resources and space of the outer Continental Shelf;

"(E) the interest of potential oil and gas producers in the development of oil and gas resources as indicated by exploration or nomination;

"(F) laws, goals, and policies of affected States which have been specifically identified by the Governors of such States as relevant matters for the Secretary's consideration;

"(G) the relative environmental sensitivity and marine productivity of different areas of the outer Continental Shelf; and

"(H) relevant environmental and predictive information for different areas of the outer Continental Shelf.

"(3) The Secretary shall select the timing and location of leasing, to the maximum extent practicable, so as to obtain a proper balance between the potential for environmental damage, the potential for the discovery of oil and gas, and the potential for adverse impact on the coastal zone.

Fair market value.

"(4) Leasing activities shall be conducted to assure receipt of fair market value for the lands leased and the rights conveyed by the Federal Government.

(continued)

Appropriations and staff, estimates.

"(b) The leasing program shall include estimates of the appropriations and staff required to—

"(1) obtain resource information and any other information needed to prepare the leasing program required by this section;

"(2) analyze and interpret the exploratory data and any other information which may be compiled under the authority of this Act;

Environmental studies and impact statement.

"(3) conduct environmental studies and prepare any environmental impact statement required in accordance with this Act and with section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332(2)(C)); and

"(4) supervise operations conducted pursuant to each lease in the manner necessary to assure due diligence in the exploration and development of the lease area and compliance with the requirements of applicable law and regulations, and with the terms of the lease.

"(c)(1) During the preparation of any proposed leasing program under this section, the Secretary shall invite and consider suggestions for such program from any interested Federal agency, including the Attorney General, in consultation with the Federal Trade Commission, and from the Governor of any State which may become an affected State under such proposed program. The Secretary may also invite or consider any suggestions from the executive of any affected local government in such an affected State, which have been previously submitted to the Governor of such State, and from any other person.

"(2) After such preparation and at least sixty days prior to publication of a proposed leasing program in the Federal Register pursuant to paragraph (3) of this subsection, the Secretary shall submit a copy of such proposed program to the Governor of each affected State for review and comment. The Governor may solicit comments from those executives of local governments in his State which he, in his discretion, determines will be affected by the proposed program. If any comment by such Governor is received by the Secretary at least fifteen days prior to submission to the Congress pursuant to such paragraph (3) and includes a request for any modification of such proposed program, the Secretary shall reply in writing, granting or denying such request in whole or in part, or granting such request in such modified form as the Secretary considers appropriate, and stating his reasons therefor. All such correspondence between the Secretary and the Governor of any affected State, together with any additional information and data relating thereto, shall accompany such proposed program when it is submitted to the Congress. Publication in Federal Register.

"(3) Within nine months after the date of enactment of this section, the Secretary shall submit a proposed leasing program to the Congress, the Attorney General, and the Governors of affected States, and shall publish such proposed program in the Federal Register. Each Governor shall, upon request, submit a copy of the proposed leasing program to the executive of any local government affected by the proposed program. Leasing program, submittal to Congress. Publication in Federal Register.

"(d)(1) Within ninety days after the date of publication of a proposed leasing program, the Attorney General may, after consultation with the Federal Trade Commission, submit comments on the anticipated effects of such proposed program upon competition. Any State, local government, or other person may submit comments and recommendations as to any aspect of such proposed program.

"(2) At least sixty days prior to approving a proposed leasing program, the Secretary shall submit it to the President and the Congress, together with any comments received. Such submission shall indicate why any specific recommendation of the Attorney General or a State or local government was not accepted. Leasing program, submittal to President and Congress.

"(3) After the leasing program has been approved by the Secretary, or after eighteen months following the date of enactment of this section, whichever first occurs, no lease shall be issued unless it is for an area included in the approved leasing program and unless it contains provisions consistent with the approved leasing program, except that leasing shall be permitted to continue until such program is approved and for so long thereafter as such program is under judicial or administrative review pursuant to the provisions of this Act.

(continued)

Review.

"(e) The Secretary shall review the leasing program approved under this section at least once each year. He may revise and reapprove such program, at any time, and such revision and reapproval, except in the case of a revision which is not significant, shall be in the same manner as originally developed.

Regulations.

"(f) The Secretary shall, by regulation, establish procedures for—

"(1) receipt and consideration of nominations for any area to be offered for lease or to be excluded from leasing;

Public notice.

"(2) public notice of and participation in development of the leasing program;

"(3) review by State and local governments which may be impacted by the proposed leasing;

State and local governments, consultation.

"(4) periodic consultation with State and local governments, oil and gas lessees and permittees, and representatives of other individuals or organizations engaged in activity in or on the outer Continental Shelf, including those involved in fish and shellfish recovery, and recreational activities; and

"(5) consideration of the coastal zone management program being developed or administered by an affected coastal State pursuant to section 305 or section 306 of the Coastal Zone Management Act of 1972 (16 U.S.C. 1454, 1455).

Such procedures shall be applicable to any significant revision or reapproval of the leasing program.

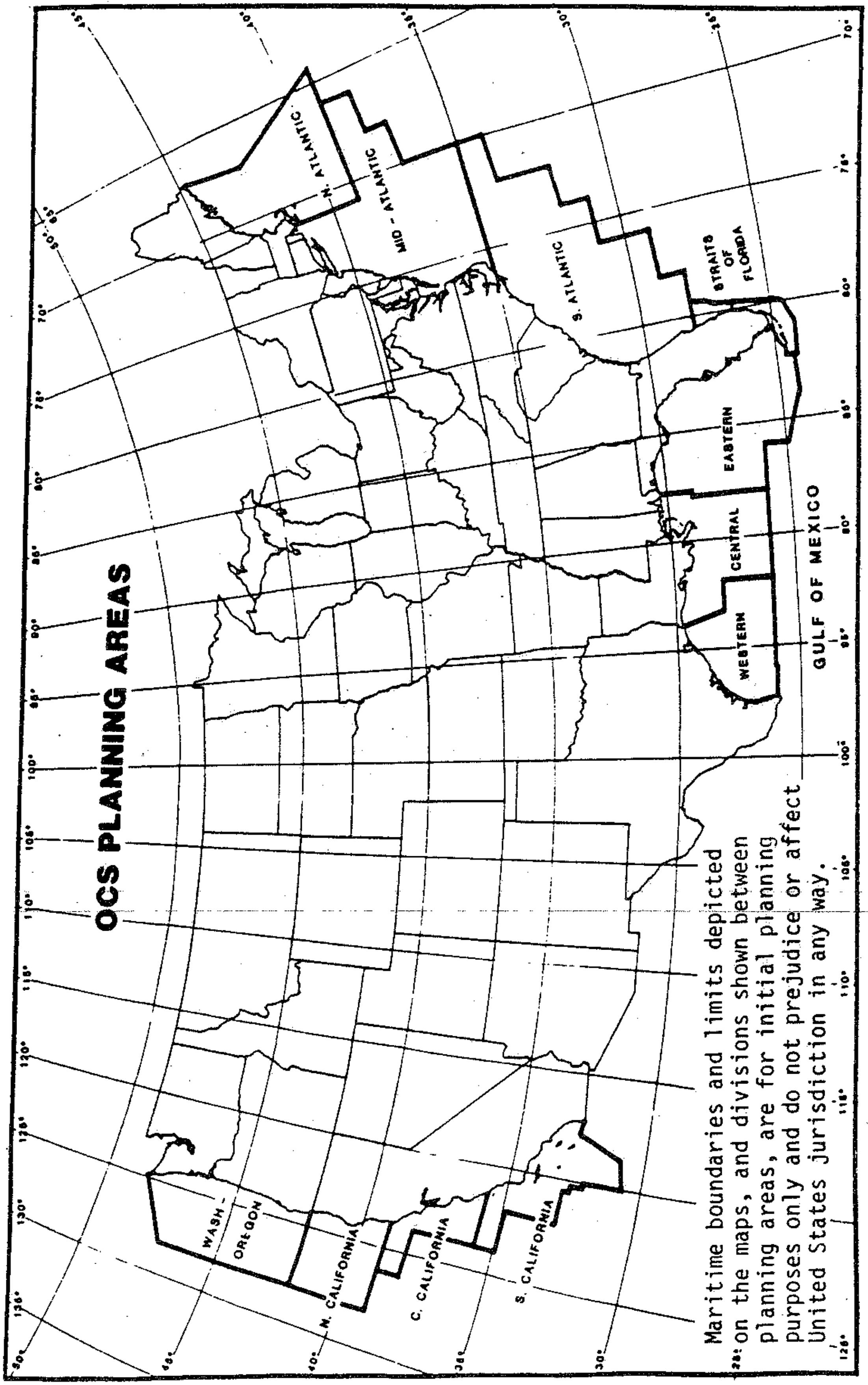
Information, availability to Secretary.

"(g) The Secretary may obtain from public sources, or purchase from private sources, any survey, data, report, or other information (including interpretations of such data, survey, report, or other information) which may be necessary to assist him in preparing any environmental impact statement and in making other evaluations required by this Act. Data of a classified nature provided to the Secretary under the provisions of this subsection shall remain confidential for such period of time as agreed to by the head of the department or agency from whom the information is requested. The Secretary shall maintain the confidentiality of all privileged or proprietary data or information for such period of time as is provided for in this Act, established by regulation, or agreed to by the parties.

"(h) The heads of all Federal departments and agencies shall provide the Secretary with any nonpriviledged or nonproprietary information he requests to assist him in preparing the leasing program and may provide the Secretary with any privileged or proprietary information he requests to assist him in preparing the leasing program. Privileged or proprietary information provided to the Secretary under the provisions of this subsection shall remain confidential for such period of time as agreed to by the head of the department or agency from whom the information is requested. In addition, the Secretary shall utilize the existing capabilities and resources of such Federal departments and agencies by appropriate agreement.

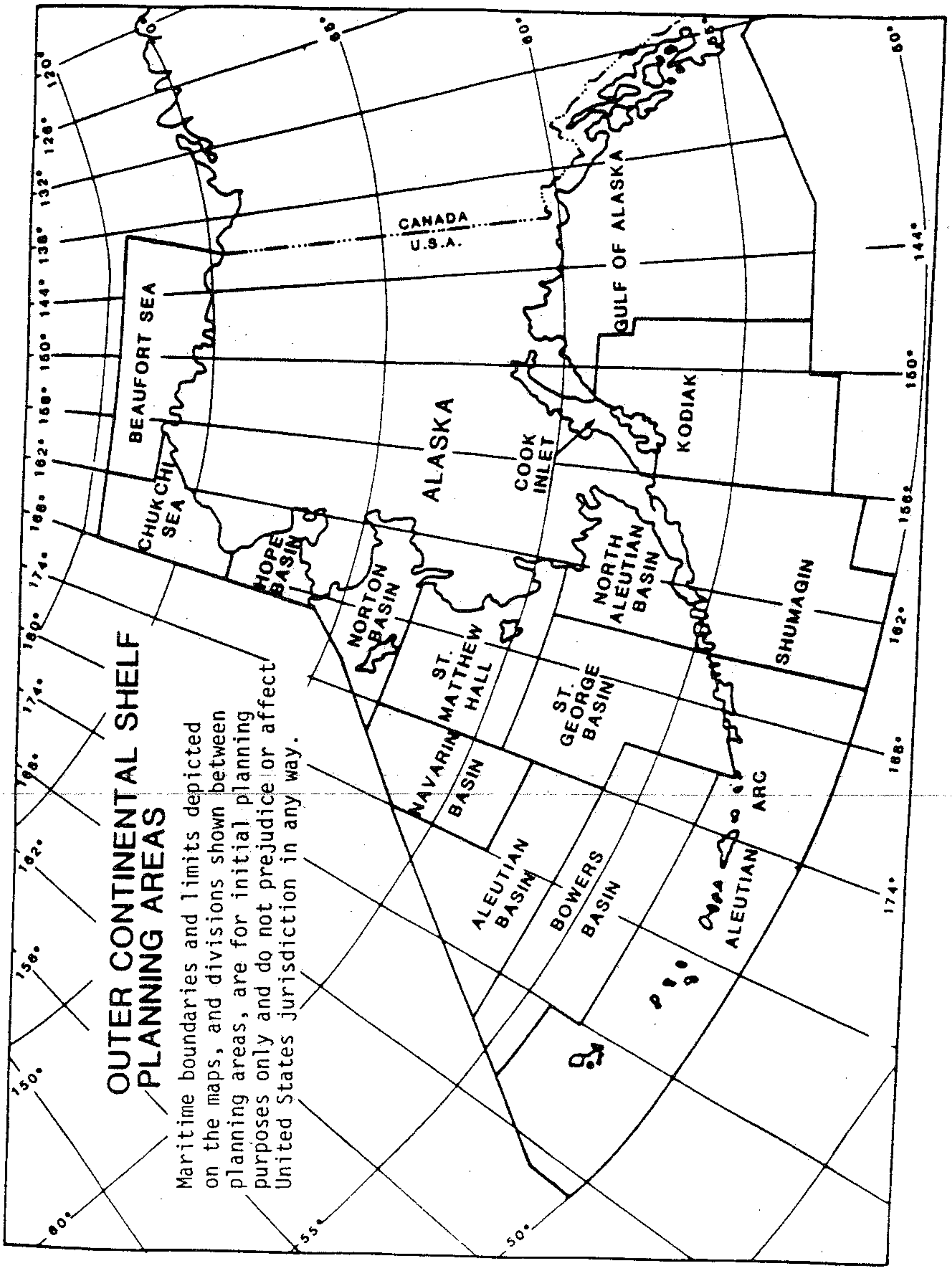
Map 1
OCS Planning Areas per The Proposed Program





Map 2

OCS Planning Areas per the Proposed Program



## I.B. Framework for Analysis: Planning for an Uncertain Future with Limited Information

Past court rulings (California v. Watt (I) and (II)) have interpreted the provisions of section 18 as requiring the consideration and weighing of the costs and benefits of OCS oil and gas exploration, development, and production through an area-by-area comparison. The benefits are primarily the net economic and energy security benefits from the additional supply of energy to the country from production of OCS oil and gas, as well as the assessment of the oil and gas resources of the OCS. The costs to be considered are a variety of social costs such as potential damages to environmental resources or conflicts with other uses of marine resources. The social costs considered here are those which are generally not included in the economic costs which lessees pay for exploration, development, and production. An analysis of marine productivity and environmental sensitivity has been prepared to serve both as an input and as a complement to the analysis of social costs.

### I.B.1. Potential Benefits and Costs

The new OCS Leasing Program, proposed for 1987 through 1992, can achieve substantial net benefits through production of the oil and gas deposits that may be discovered on the portions of the OCS that are not leased as of the start of the new program. The detailed analysis of benefits and costs and the summation of the net social value (net economic value minus social costs) of leasing appear in Part II of this SID.

The MMS estimates that as of mid-1987, unleased undiscovered risked OCS oil and gas resources in leasable prospects will have a net economic value of between about $20 billion and $84 billion ($1987), over the range of assumed starting oil prices (see Appendix F). The potential net benefits actually realized will depend on many factors: how much oil and gas are actually discovered in OCS acreage leased in the new program; their resource and economic characteristics; future conditions in world energy markets; the ways in which oil and gas companies respond in making investments in OCS resources ; and the actual effects of OCS oil and gas activities on the environment. The potential benefits from unleased acreage can also change in response to changes in the amount of unleased acreage in the national inventory, the size of the private lease inventory, and the amount of available resource information. Estimates of net benefits projected to be realized are presented in the valuation of program alternatives which appears in Part III below and in Appendix R.

Since section 18 requires that the Secretary's selection of a leasing program be based on a consideration of the required technical analyses, it is important to indicate the limitations and implications of the assumptions made in those analyses. Appendix S describes this subject in detail.

A recognition of those limitations has important implications for the formulation of a leasing program, especially with respect to the issue of flexibility.

### I.B.2. Limitations on Assessing the Effects of OCS Leasing

It is important in reviewing the materials in this document to recognize the limitations inherent in assessing the effects of OCS leasing and subsequent OCS activities. Because of such limitations, the information assembled for the Secretary's consideration required the development of new methods of analysis, the projection of numerous future events and conditions, and professional judgments on a wide variety of technical issues.

Section 18(a)(2) speaks in terms of the "Timing and location of exploration, development, and production of oil and gas . . . ." One fundamental limitation on planning for those activities is that the Federal Government can only offer OCS oil and gas leases for purchase by private firms. In OCS lease sales, qualified bidders are given the opportunity to bid on the clearly defined and limited rights to explore, develop, and produce oil and gas which are set forth in the lease, the applicable stipulations, and the large body of applicable laws, regulations, and operating orders. Firms issued leases may then make the additional investments needed to seek, find, and produce oil and gas. The limits of predicting firms' investment decisions thus become, in turn, limits on predicting OCS activities.

The offering of OCS blocks for bids does not in itself cause bids to be submitted or leases to be issued on blocks which are bid upon. In fact, it is very difficult to predict the patterns of bidding and leasing which will occur at a given lease sale. For oil and gas exploration, firms have alternatives to U.S. OCS oil and gas leasing. Firms can lease in the U.S. and foreign onshore markets and in the State and foreign offshore markets. Additionally, the issuance of leases does not necessarily cause investments in exploratory drilling and development. Such investments occur in response to continually changing perceptions about the potential payoffs that might result. In fact, many leased blocks are not drilled because of information obtained after leasing.

All of the subsequent effects--both costs and benefits--of OCS exploration, development, and production depend upon the patterns of leasing and investment in combination with the actual location, quantity, and value of the hydrocarbons discovered--if any. Those quantities and values, in turn, can only be estimated in probabilistic terms in advance of lease sales and exploratory investments. Further, discovery of new fields and the amount discovered often bear little relation to the level of leasing and exploration costs, especially in frontier areas. Thus, the very nature of the activity of offering leases and awaiting the results of subsequent investment and exploratory drilling severely limits the precision possible in the prediction of the resultant effects.

### I.B.3 Recognition of the Limitations of the Technical Analyses

The precision with which future OCS oil and gas activities can be planned is further limited by the kinds of considerations on which the 5-year program is to be based, pursuant to section 18 as interpreted by the court. The factors which section 18(a)(2) requires the Secretary to consider and the balancing which section 18(a)(3) requires the Secretary to perform are the legal bases for the technical analyses which appear in Part II.B of this document. These analyses serve as a key basis for the development of the 5-year program. Notwithstanding the sound technical basis of those analyses, the exercise of judgment not reducible to technique is a crucial element in every one of them. This issue is examined in greater detail in Appendix S.

## II. Section 18 Analyses

### A. National Energy Needs and the OCS Oil and Gas Leasing Program

Section 18(a) of the OCS Lands Act mandates that the OCS Oil and Gas Leasing Program prepared by the Secretary shall be one "which he determines will best meet national energy needs for the five-year period following its approval or reapproval . . . ." The provision that the 5-year program be keyed to national energy needs reflects the first purpose of the OCS Lands Act Amendments:

> Section 102. The purposes of this Act are to--
>
> (1) establish policies and procedures for managing the oil and natural gas resources of the Outer Continental Shelf which are intended to result in expedited exploration and development of the Outer Continental Shelf in order to achieve national economic and energy policy goals, assure national security, reduce dependence on foreign sources, and maintain a favorable balance of payments in world trade. . . .

It is also relevant to note here that the Mining and Minerals Policy Act of 1970 (30 U.S.C. 21a) provides that:

> The Congress declares that it is the continuing policy of the Federal Government in the national interest to foster and encourage private enterprise in
>
> (1) the development of economically sound and stable domestic mining, minerals [defined to include oil and gas], metal and mineral reclamation industries, [and]
>
> (2) the orderly and economic development of domestic mineral resources, reserves, and reclamation of metals and minerals to help assure satisfaction of industrial, security, and environmental needs . . . .

#### National Economic and Energy Goals

The 1985 National Energy Policy Plan issued by the Department of Energy states that

> For the rest of this century, oil and gas are likely to remain the principal energy sources of the American people. They now provide about two-thirds of the commercial energy used in the United States, and they are projected still to be furnishing more than half in the year 2000.
>
> In addition to promoting a free-market economy and full deregulation of natural gas, the most vital component of Federal action is the timely development of oil and gas resources on federally managed areas of the Outer Continental Shelf . . . .

While U.S. production of oil has recovered from the lows of a few years ago, the Nation's oil and gas reserves have not risen. In response to the price rises of the 1970's and very early 1980's, they have only stopped falling sharply--oil reserves have fallen by less than 5 percent and gas reserves by less than 1 percent from 1980 to 1984. If this country fails to find and develop new oil and gas fields--and to squeeze every economical drop from existing reservoirs--it stands a chance of letting the progress of the past few years slip away. At the same time, the Interior Department's estimated (not proved) reserves on the OCS have been greatly diminished because the experience in the frontier areas of Alaska and the Atlantic coast has been disappointing. In spite of all the past optimism, there is not a single producing well in Federal waters off Alaska at present, and it is not clear to what extent there will be.

Because of the foregoing, the Administration opposes any moratorium on OCS leasing. By preventing development of domestic resources that are known to be available, delaying work on the OCS only strengthens OPEC's efforts to control production and raise prices. The Nation's dependence on imported oil increases, its energy security is lessened, and the pace of economic growth is inevitably slowed (pp. 4-5).

Need for the Long-Term Perspective

Our perspective on OCS leasing must be long-term because the lead-times needed to bring new offshore fields into production are substantial. Once a sale is scheduled on a 5-year program, the presale process leading up to holding the sale can take over 2 years. Several more years are needed by industry to evaluate leases, determine whether drilling is warranted, and drill exploratory and delineation wells. The time elapsed from leasing to initial production can extend from about 4 to 13 years, depending on infrastructure needs, proximity to markets, transportation problems, and operating conditions in the different regions.

Another constraint on OCS leasing is the extensive exploration and development permitting process, which often requires operators to obtain multiple Federal, State, and local permits.

Thus, the new 5-year OCS leasing program is designed to help meet domestic energy supply requirements during the 1990s and the first quarter of the 21st century. It is therefore not today's market conditions that should dominate our planning, but conditions anticipated in 10 to 30 years.

In 1985, imports of crude oil and petroleum products represented about 33 percent of the petroleum products consumed in the United States. Even before recent price declines and attendant increases in oil imports, the Annual Energy Outlook 1985, issued in early 1986 by the Energy Information Administration, projected that in 1995, imports of crude oil and refined products could range between 47 and 65 percent of the petroleum products consumed in the United States, with 55 percent as the base case projection.

The consequence of the long-term character of OCS development is that decisionmaking about it should not be guided by the trend of the day. Leasing of OCS acreage is unusually vulnerable to short-term phenomena which can disrupt it in ways that can be made up only at substantial cost in time and opportunity. Public policy concerning OCS leasing should, therefore, be guided by a steady, long-term perspective on the potential seriousness of the risks involved in oil supply disruptions, their unpredictability, and the long lead-times necessary to make OCS production available for use. Without the assurance that OCS leasing policy will remain firm, industry would likely be reluctant to invest the huge sums required to develop OCS resources.

What this means can be illustrated by examining the argument that potential oil and gas resources be withdrawn from leasing in certain areas and saved as a "reserve" for use in a national emergency. Given the years of lead time needed to bring OCS resources to market, the only way in which potential oil and gas resources can constitute a useful reserve in case of an emergency is if they are not withdrawn from the normal course of exploration and development through which drilling can locate and delineate the reserve and the necessary production infrastructure can be put in place.

Contribution of OCS Leasing to Meeting National Economic and Energy Goals

OCS production provides a great source of national wealth and nationwide employment. OCS oil and gas produced at a cost lower than prices found in the world oil market contribute to the Nation's economic productivity. The greater the amount of OCS oil and gas produced at costs less than world oil prices, the greater is that contribution. Economic productivity is increased by allowing firms a range and sequence of opportunities that will encourage an economically efficient path of investments in OCS exploration and production. In general, this will increase the available knowledge concerning potential OCS hydrocarbon resources and, hopefully, the amount of oil and gas discovered and produced, thus benefiting the economy.

In addition, domestic OCS production has the potential to contribute to the reduction of other payments to foreign nations. The Nation's production of oil and natural gas liquids peaked in 1970 and dry natural gas production peaked in 1973. The lower levels of production since the 1970s parallel the lower levels of oil and gas reserves which have resulted because America has not been finding enough new petroleum reserves to replace the oil and gas we have been using. Since onshore resources are declining, it is expected that the relative contribution from OCS production will increase. Economically recoverable reserves from existing OCS leases are estimated at over 13 billion barrels of oil equivalent (BOE). In addition, the potential for future discoveries on the OCS is still significant (see Appendix F).

In 1985, the United States spent over $52 billion to purchase foreign crude oil and petroleum products. If the United States did not need to import those hydrocarbons, our 1985 balance of trade deficit could have been reduced by over 35 percent. Oil and gas from the OCS represented about one-eighth of our domestic oil production and over one-fourth of our domestic natural gas production in FY 1985. On a BOE basis, OCS production provided about 3.29 million BOE per day in FY 1985, of which about 67 percent came from natural gas and about 33 percent came from oil and natural gas liquids. Importing an equal amount of oil in 1985 would have added roughly $40 billion to the balance of payments deficit.

In addition to benefiting from the use of domestic oil and gas to fuel the general level of economic activity, the American people benefit in their roles as owners, through the Federal Government, of the resources of the OCS. The benefits came from production of any OCS resource costing less to find and produce than the price at which it can be sold (see Appendix F.)

In addition, OCS oil and gas production helps to ensure national prosperity and energy security by providing a secure supply of the fuels essential to the production and distribution of virtually all other products.

Means of Pursuing National Energy and Economic Goals

The Nation's dependence on imported oil for the pursuit of national energy and economic goals makes it vulnerable to the damaging effects of oil supply disruptions. Disruption of supplies of oil from abroad causes disruption in the production and consumption of goods and reduces economic productivity. This causes decreases in income and increases in consumer price levels. The 1984 Office of Technology Assessment (OTA) Report, U.S. Vulnerability to an Oil Import Curtailment, estimates that a significant disruption of oil imports could result in a reduction of the Gross National Product of 3.5 to 6.2 percent, accompanied by increased unemployment of 1.7 to 2.3 percent (pp. 146-147; see also Appendix F of this SID).

However, most measures to assure that our national energy needs will be met have economic costs. Thus, the economy needs to adjust continually, balancing the costs of those measures against their economic benefits. The OCS leasing program can contribute to meeting both national energy and economic needs by helping to reduce oil imports and providing a source of domestic supply in periods of future disruptions and higher prices.

Over the long run, OCS oil and gas resources will make a contribution to economic productivity if investment and production decisions can adjust quickly to changing world energy markets. An OCS leasing program can help meet the Nation's energy and economic needs by providing opportunities for investments in exploration and development when they are economically timely. Such a program would allow rapid increases in leasing and investment if world oil prices were to increase to higher plateaus while allowing a lower investment and production rate during periods of lower prices. On the one hand, it is possible that world oil prices in the 1990s will be sufficiently low to render uneconomic many of the oil and gas prospects remaining to be leased on the OCS. On the other hand, oil prices may not decline further or remain low for very long. Higher oil prices would increase the number of good prospects for discovery of oil and gas on the OCS. The rate of leasing and investment in exploration would be higher. The resulting production would help the economy use less high cost imported oil, thus increasing its economic productivity (see Part II.B.1).

Allowing a quicker shift from imported to domestic oil when oil prices increase reduces the economic costs of abrupt changes in the world oil supply. Ensuring such flexibility in the OCS leasing program can contribute to meeting our national energy needs--but the long lead time for the development of OCS oil and gas resources requires that flexibility be ensured throughout the program and well in advance of emergency situations. This point is discussed further at the end of this section.

## National Security Concerns Relevant to OCS Leasing

The actual disruptions in oil imports which the United States has suffered make clear the nexus of national security policy and economic policy with respect to the oil import issue. The disruptions of 1973 and 1979 both arose in the international arena and both had substantial recessionary effects on the United States economy. Thus, planning for the future involves consideration of both the national economy and the national security policy aspects of the oil import issue.

National security considerations clearly point to the need for flexibility in the OCS leasing program. The continuing dependence of the United States on oil imports for a substantial part of our oil consumption creates a number of national security concerns. This is especially so because of the dependence of the world oil market on oil supplies concentrated in Middle East OPEC nations.

The potential for an oil supply disruption imposes political limits on the flexibility of our national security policy, including our ability to respond to foreign security threats.

Our dependence on foreign nations for so essential a commodity as oil creates the potential for the United States to be drawn into dangerous political and military situations involving those nations.

Dependence on oil imports entails dependence on extended supply lines (tanker routes) which present a target for attack and thus add to our defense burden. This added defense burden involves both the deterrence of attacks as well as actual defense in the event of an attack.

Many other nations, including our allies, are faced with the same set of problems. The restraints on them indirectly but effectively pose further limits on our own national security flexibility. Thus, any improvement in our ability to assist them in meeting their energy needs in turn improves our ability to pursue our own national security goals and fulfill our role as leader of the Western alliance and as a participant in the energy security program of the International Energy Agency

Furthermore, if there were a world oil shortfall, all of our suppliers, including non-OPEC suppliers, might reduce oil shipments to us in order to honor all of their export contracts equitably. Thus, our oil import vulnerability is not limited to the amount of our OPEC imports.

In normal times, oil can be obtained through the international marketplace, where considerations are primarily economic. In times of hostilities, however, production and transportation of oil can be significantly affected by non-economic forces and the physical control of oil becomes more important. In contemplating such a possible state of affairs, it is important to recognize that key weapons systems in the Nation's current arsenal and under development for future use are designed to use liquid hydrocarbon fuel. In Fiscal Year 1983, for example, the armed forces used over 177 million barrels of oil, which was the equivalent of over 58% of OCS oil production in that year. The most secure sources of supply for such fuel are, clearly, domestic sources. Given the legal tie between leasing and exploration/development and the long lead-time involved in finding and developing OCS oil and gas, the only way that OCS resources could be made readily available for this purpose is to allow leasing and development to be pursued in peacetime.

This consideration is reflected in section 12(b) of the original OCS Lands Act:

> In time of war, or when the President shall so prescribe, the United States shall have the right of first refusal to purchase at the market price all or any portion of any mineral [including oil and gas] produced from the outer Continental Shelf.

National security concerns over dependence on imported oil are highlighted by the effect of recent price declines. That decline has led to a contraction within the oil and gas industry which reduces its ability to respond quickly to sudden price increases that could result if there were a disruption of oil imports.

OCS Leasing in Perspective

The question of how to control our reliance on imported oil over coming decades can be seen as a question of balancing the economic productivity gained by using cheaper imported oil during times when world prices are lower against the potential costs of supply disruptions. Furthermore, it is quite possible that the total U.S. endowment of oil and gas resources will not be sufficient in amount and low enough in cost for production to keep pace with demand through the coming decades during which relatively low cost reserves in the Middle East and elsewhere are depleted. Nonetheless, the OCS oil and gas leasing program can continue to make a significant contribution to meeting national energy needs.

In order to understand the contribution which OCS oil and gas leasing can make to long-term energy supplies, it is useful to review some of the other efforts and proposals which have been made to reduce our vulnerability to oil supply disruptions. While these approaches have a great deal to offer, they nonetheless have limitations which call for the kind of contribution which the OCS leasing program can make to the pursuit of national energy goals. These approaches include: conservation; the creation of the Strategic Petroleum Reserve; the diversification of supply; the concept of developing an oil replacement capability; and reliance on alternative energy sources.

--Conservation

The 1985 National Energy Policy Plan identifies conservation as ". . . the most expeditious way to reduce the need for new or imported energy resources; and in fact it contributes more to balancing our national energy ledger than does any single fuel source" (p. 5). Even taking conservation effects into consideration, however, DOE projects the need to import substantial amounts of petroleum products over the next decades. In addition, one unfortunate side-effect of the recent decline in oil prices is that the economic incentive to incur the costs of energy conservation investments is likely to be reduced.

--The Strategic Petroleum Reserve

At its current level of about 500 million barrels, the Strategic Petroleum Reserve (SPR) can substitute for several months of oil imported at current rates of supply and demand. The SPR's greatest usefulness is in blunting supply cuts and the resultant price spikes in the short-run. In the case of a disastrous reduction of oil supply over a sustained period, the SPR--even if filled to its ultimate capacity, once envisioned as one billion barrels, but now set at three-quarters of a billion barrels--would prove of limited usefulness. While such a disaster is not currently anticipated it cannot be dismissed as a possibility. After all, the West's supply of oil is disproportionately dependent on the oil production of a handful of nations whose political future cannot be said to be assured.

--Diversification of Sources of Supply

The diversification of sources of supply which the United States and, to a lesser extent, its allies, have been able to achieve presents the prospect of significant protection against the disruption of oil supplies from the Middle East. Yet its potential to insulate the United States from vulnerability to such disruptions also has limits. First, it could well be that during a significant supply disruption, remaining suppliers might ration the added supplies which they are capable of providing in ways that may not be particularly favorable to the United States. Second, under the auspices of the International Energy Agency, the United States and many of its allies are obliged to share oil in the event of a major disruption of oil supplies. That sharing system has never been put to a real test, however. Furthermore, by relying on other nations to share their limited supplies with us in order to meet our great oil consumption demands, we could well strain our relations with the nations on which we relied for such sharing and with those with whom we would be competing for supplies. Thus, the less we need to depend on such sharing agreements, the better off we would be in terms of both certainty of supply and relations with other nations.

--Oil Replacement Capability

Another useful concept is investment in oil replacement capacity--i.e., incurring the costs of developing the capacity to deploy technologies and strategies which minimize the effects of a long-term oil supply shortfall. Examples of oil replacement capacity include fuel switching and increased efficiency of fuel use. The development and maintenance of oil replacement capacity, however, can be more costly than the reduction in imports achieved by increased OCS oil production. Furthermore, an oil replacement strategy does not exhaust the range of useful responses to the problem posed by our vulnerability to the disruption of oil supplies from abroad. An oblique confirmation of the continuing importance of increased domestic supplies of hydrocarbon fuel is implicit in the OTA oil replacement study's discussion of the desirability of the deregulation of the price of natural gas so as to increase its supply (at pp. 27-28, 30).

--Alternative Energy Sources

Several energy sources other than oil and gas are expected to be used in this Nation during the remainder of this century and the first quarter of the next. These sources include coal, hydroelectric, nuclear, oil shale, tar sands, and geothermal energy. Nonconventional forms such as wind, solar, and converted biomass energy may also be used to a much lesser extent. Coal will probably be the most heavily used alternative source of energy, followed, in order, by hydroelectric, nuclear, and geothermal energy (see Appendix F).

Notwithstanding use of the several alternative forms of energy discussed above, the U.S. Department of Energy projects that over 46 percent of the Nation's energy demand in the year 2010 will be met by oil and gas. About 40 percent of this needed oil and gas is projected to be imported. /1

By providing opportunities to increase our domestic supplies of oil and gas, the OCS leasing program makes an important--and less costly--contribution to energy security, in addition to the three strategies described above. Leasing of the OCS also provides supplies which are available over the long-term.

Information Benefits

Information benefits are another type of benefit from OCS leasing, exploration, and development. Information benefits are the benefits to the Nation--beyond economic benefits--of greater knowledge about the extent of oil and gas resources on the OCS.

The generation of information benefits is one of the specified purposes of the 1978 OCS Lands Act Amendments. Section 102(9) of the Amendments states that one of the purposes of that act is to "insure that the extent of oil and natural gas resources of the Outer Continental Shelf is assessed at the earliest practicable time"(43 U.S.C. 1802 (9)). It is the nature of oil and gas resource assessment that only drilling can confirm the existence and size of an oil and gas accumulation. On the OCS, drilling for oil and gas is essentially tied to leasing and thus to the 5-year leasing program.

As in the case of production, the contribution to the overall picture made by any particular lease may be small, but without the small pieces, the overall picture cannot be created. Of all the small pieces, the first wells in an area generally provide the most information. Where the existence of commercial accumulations of hydrocarbons has not been demonstrated, there is usually a high degree of dependence among estimates of resources on prospects. In these cases, the information generated by exploration on a given prospect generally sheds a great deal of light on the resource potential of the surrounding acreage. /2

The estimated size of the resource base of the OCS has major implications for the country's energy and national security policies. Clearly, if U.S. oil and gas resources were very great or very limited, the implications for our foreign policy would be very different. While the resource potential of the U.S. is estimated to be somewhere between those two extremes, it is very useful for the Nation to know better where it stands.

The Department of State is also particularly concerned with estimates of OCS oil and gas resources regarding international boundary negotiations with neighboring nation-states concerning jurisdiction over those resources. Such negotiations are ongoing concerning several planning areas.

The Department of Energy has made explicit use of estimates of undiscovered OCS oil and gas resources in developing its report, Replacement Costs of Domestic Crude Oil (1985), which is designed to aid in planning for fossil energy research and development.

/1 U.S. Department of Energy, National Energy Policy Plan Projections to 2010, 1985, Tables 3-4 and 3-5.

/2 See, for example, MMS, Estimates of Undiscovered, Economically Recoverable Oil and Gas Resources for the OCS as of July 1984, (OCS Report MMS 85-0012), p. 22.

The OTA Report on Oil and Technologies for the Arctic and Deepwater (May 1985) provides a useful summary of this issue in stating that

> If Congress wishes to pursue the objectives of the OCS Lands Act, it is important that the oil and gas industry have access to Federal offshore lands to more accurately determine the resource potential of frontier areas. A "second-round" leasing strategy may also be needed to assess the extent of smaller offshore reservoirs that could cumulatively contribute to the Nation's energy security [p. 5].

The OTA report also states that

> Accurate knowledge of the resource potential of the Nation's offshore areas is critical to overall energy planning and to making decisions about the offshore leasing program and alternative energy programs [p. 11].

That report highlighted the decline from previous levels of the most recent MMS OCS estimates of oil and gas resources offshore Alaska and in the Atlantic and examined its implications for U.S. energy policy. Some interpretations of the latest data have focused on that decline as supporting policies of energy conservation and alternative energy research. Others have gone so far as to suggest that somehow the new data mean that OCS leasing, exploration, and development are not worth pursuing--even for the substantial economically recoverable resources which are still estimated to exist. The Department of the Interior--complementing the first view and opposing the second--emphasizes the substantial contribution which OCS leasing, exploration, and development will continue to make in terms of net social value, national security, and information benefits. For only through actual exploratory drilling can more knowledge be obtained about the extent of our remaining oil and gas resources.

## Consideration of Revision of OCS Leasing Policies

In response to the recent decline in oil prices, on June 6, 1986, the President announced an initiative to preserve the Nation's energy resources. On October 31, 1986, MMS published a notice in the Federal Register requesting comments on policies under consideration to encourage leasing, exploration, and production on the OCS (51 FR 39810). In particular, comments were requested on: returning to the former minimum bid level of $25 per acre; using some form of a work commitment bidding system; employing variable rentals; offering larger sized tracts; and deferring payment of 80 percent of the bonus on leased tracts. These policies are being considered for adoption on a sale-specific rather than a programmatic basis.

## Consideration of the March 1987 Report on Energy Security

The March 1987 report by the Department of Energy entitled Energy Security--A Report to the President of the United States presents a comprehensive analysis of the current and projected energy needs of the United States within the context of our energy and national security interests in the next decade. The report analyzes and projects the supply of and the demand for all our sources of energy - oil, coal, natural gas nuclear power, electricity, renewables - as well as the opportunities for achieving greater efficiency in energy use. It is clear that oil is and will continue to be a vital component of our energy mix well beyond the year 2000. Domestic oil is characterized in the report as our critical resource at risk. Our economy's use of oil is concentrated in our large transportation sector, which accounts for over 60 percent of the oil we consume as a Nation.

Because of the precipitous drop in oil prices in the first half of 1986, U.S. domestic oil production has fallen sharply by almost one million barrels of oil a day. Imports rose to approximately one-third of our domestic consumption in 1986. In the 1990's, imported oil is expected to increase to approximately 50 percent of our oil consumption. The major source of our increasing oil imports has been and is projected to be the politically unstable region of the Middle East with its tremendous reserves and low costs of extraction.

The report cautions that despite the many gains the U.S. has made in building a stronger foundation of energy security, the enormous toll in our domestic petroleum sector resulting from the recent world oil price declines portends serious problems for the future. Decontrol of oil prices and the large strategic petroleum reserves that have been established in the U.S. will make it possible to respond more effectively to any future supply disruptions than has been the case in the past. If adequate supplies of oil and other energy resources continue to be available at reasonable prices, the importation of low-cost crude oil will provide a boost to the U.S. economy. At the same time, however, increased reliance on relatively few oil suppliers implies certain risks:

- If a small group of leading oil producers can dominate the world's energy markets, this can result in artificially high prices (or just sharp upward and downward price swings), which would necessitate difficult economic adjustments and cause hardships to all consumers.

- Revolutions, regional wars, or aggression from outside powers could disrupt a large volume of oil supplies from the Persian Gulf, inflicting severe damage on the economies of the United States and allied nations. Oil price increases precipitated by the 1978-79 Iranian revolution contributed to the largest economic recession since the 1930's. Similar or larger events in the future could have far-reaching economic, geopolitical, or even military implications.

The price declines of 1986, uncertainty about future prices, and disappointing domestic drilling results have resulted in a precipitous decrease in exploration for oil in the U.S. The high cost of exploration in the U.S. relative to the Middle East will direct future drilling efforts to those areas with a chance of yielding large finds. The report indicates that some offshore regions and North Alaska now offer the best chance of yielding large new oil fields. The coastal plain of the Arctic National Wildlife Refuge is considered to have the potential for oil reserves the size of those in Prudhoe Bay. In addition, in the high case, about 4 billion barrels of recoverable undiscovered oil resources are estimated to be in the Outer Continental Shelf off the California coast. It may be incongruous to restrict access to areas offshore which have high potential to contribute to our domestic energy production in a way that benefits the taxpayer and the economy and in an environmentally safe manner, at a time when other options to increase energy security have the potential to impose substantial costs to the taxpayer, the economy, and the environment.

## II.B. Planning Area Analyses

Pursuant to California v. Watt (II), the Secretary is provided with both quantitative estimates and qualitative information indicating the benefits of oil and gas development and its various costs for all of the acreage that is expected to be unleased in each planning area at the beginning of the new 5-Year Program. The results of these statutorily required comparisons of planning areas provide a basis for determining the timing and location of lease sales in the program. It also indicates whether there is a basis to exclude any planning area from leasing during the 1987-1992 period. These analyses also provide input for the discussion of the equitable sharing of developmental benefits and environmental risks in Part II.C. and the discussion of balancing in Part II.D.

In the July 1984 request for comments on the development of the new 5-year program, the entire OCS was divided into 24 planning areas. For the March 1985 Draft Proposed Program, the OCS was reconfigured into 26 planning areas. First, the area offshore California was reconfigured from two planning areas (Southern California and Central/Northern California) to three planning areas (Southern California, Central California, and Northern California). Second, the southern part of the South Atlantic planning area and the Florida Keys out to the Dry Tortugas were made the Straits of Florida planning area. This reconfiguration was used as the basis for the section 18 analyses and the schedule options for Secretarial decision on both the Proposed Program and the Proposed Final Program.

The planning areas analyzed are described in Appendix N. The planning areas as so described are for planning purposes only and should have no application or effect whatsoever as to the possible extent of present or future U.S. jurisdictional claims. For the Proposed Final Program, Option A.1.a would extend the seaward boundaries of the three Gulf of Mexico planning areas and the Straits of Florida planning area. Note that four planning areas (Aleutian Basin, Bowers Basin, St. Matthew-Hall, and Aleutian Arc) have been deleted from further consideration because they were estimated to contain negligible resources and have very low industry interest.

This SID includes refined section 18 analyses for the Proposed Final Program. For analyses in this final stage, the estimates of resource values for certain planning areas have been revised to account for 15 subareas which were proposed for deferral in the Proposed Program (see discussion in part III). Subarea deferrals at the 5-year program stage can affect not only the acreage available for leasing but also its estimated value. All estimates of resources and net economic value in this part are for the remainder of affected planning areas, assuming the exclusion of the 15 subareas proposed for deferral as part of the Proposed Program. The estimates are revised to show the remainder of the planning area because the Section 18 analysis and decision requirements apply to the area to be scheduled for lease sale, as distinguished from the areas deferred from leasing. Other subareas which the Secretary may consider for possible deferral are treated independently and the results are displayed in the Subarea Attachment. Results are shown for resources remaining in a planning area after individual subarea candidates are assumed to be deferred as well as a cumulative case which shows remaining resources and net economic value (NEV) if all candidates in the area were selected for deferral.

In a number of cases, deferral of subareas does not materially change the conditional mean estimate of resources remaining in a planning area. However, it should not necessarily be concluded that the subarea being considered therefore has no resource potential. Even if there appears to be no material change in the estimates, the uncertainties inherent in projections of undiscovered resources make it imprudent to conclude that the subarea is without resource potential. Until an area has been leased and explored, no definitive conclusions should be drawn. The results of the quantitative assessment of remaining resources (after the 15 subareas deferrals) will help to indicate a planning area's revised resource potential for comparison with other planning areas for the purpose of designing a lease sale schedule.

The area-by-area analysis of relative values based on estimates of costs and benefits exclude the effects of lease sale timing by assuming that all resources are leased at the beginning of the 5-year program. This approach was upheld by the court in California v. Watt (II). (The Court agreed that lease sale timing for an area within the program was to be some function of its relative value. Since there are numerous times and frequencies possible for lease sales within each area, it was determined to be reasonable to assess relative value in a manner that did not first require the specification of the outcomes that the assessment was to yield, namely the timing of sales in each area).

To provide for comparability of value estimates among the planning areas the following general approach was employed:

1. All OCS oil and gas resources estimated to be worth acquiring by private industry under specified economic conditions were assumed to be leased as of mid-1987 in each planning area. Exploration, development, and production would then follow according to scenarios characteristic of the planning area.

2. Net present value estimates were calculated for more than 2400 geological prospects. A base case economic scenario was stipulated having July 1984 starting prices of oil of between $14 and $29 per barrel, a 1-percent real annual price growth rate, a 5-percent annual inflation rate and an 8 percent real discount rate (equal to a 13.4 percent nominal discount rate). Sensitivity analyses were conducted around the base case estimates which allowed for variations in the assumptions for the range of starting prices of oil, the ratio of oil to gas prices on a BTU-adjusted basis, the annual average growth in oil prices, and the discount rate. The results for the low and high starting prices (i.e., $14/bbl. and $29/bbl.) are displayed in Part II of the SID. The remaining sensitivity calculations are included in Appendix F.

It is important to note that the MMS aggregate estimates of resources and net social value, as well as industry rankings for various planning areas, do not distinguish between areas in which high-valued resources and industry interest are concentrated in a portion of a planning area and those in which low-valued resources and industry interest are widely distributed throughout the planning area. It should also be noted that the presale process provides ways of adjusting the size of the area offered in lease sales in order to accommodate these differences within areas. The presale process is discussed further in Part III and Appendix P.

For the Proposed Program and the Proposed Final Program, once the options for schedules were developed, an analysis was made of value which incorporates the costs and benefits of leasing given the lease sale timing options. (See Part III.A and Appendix R.) For analyses of alternative schedule options, such as appears in the SID, EIS and Appendix R, resource estimates reflect the range of values resulting from potential subarea deferrals (ranging from no deferrals to the cumulative deferral case).

## II.B.1. Estimates of Hydrocarbon Resources and Economic Benefits

Estimates of the oil and gas resources and their net economic values were made to facilitate the Secretary's consideration of the potential for oil and gas discovery and the contribution to the Nation's energy and economic needs that could result from leasing in each of the OCS planning areas. Three major improvements were made over the estimating procedures used in the formulation of the 1982 program:

1. The estimate of oil and gas resources in each area was based upon an extensive evaluation of an inventory of identified unleased prospects rather than upon calculations employing the aggregate volumes of oil and gas likely to be found (used in the 1982 analysis).

2. The estimates of resources and net economic values in each area were based upon a wider range of characteristics (e.g., variation in prices and discount rates) that influence the economics of various prospects than was the case in the 1982 analysis.

3. Three different categories of undiscovered hydrocarbon resource estimates were developed for use in the 5-year program analyses. Each type of resource estimate provides important information about the OCS planning areas for use in scheduling decisions:

   - conditional economically recoverable oil and gas resources;
   - risked economically recoverable oil and gas resources; and
   - leasable oil and gas resources.

These improvements make it possible for the Secretary to consider in more detail the aspects of each planning area that characterize its potential for yielding oil and gas discoveries and economic benefits. The economic measure of the benefits which the Nation can realize from OCS oil and gas exploration and development is the net economic value of the hydrocarbon resources. The net economic value of an oil and gas accumulation measures the difference between the revenues from the sale of oil and gas produced and the costs of exploration, development, production, and transportation--both costs and revenues being appropriately discounted to present value. Estimates of net economic value take into account the probabilities of the various events that affect the resource and economic outcomes of investment in an unexplored prospect. Net economic value is also a measure of the benefits to the economy in the form of cash bonuses, royalties, rental fees, incremental taxes, and after-tax business profits. The sum of the amounts expected to be captured in these forms is equal to the difference between expected production revenues and costs (see introduction in Appendix F).

Hydrocarbon Resources

In selecting the size, timing and location for leasing, one factor which the Secretary is directed by the Act to consider is the potential for hydrocarbon occurrences in each planning area. Since the location and extent of undiscovered hydrocarbon resources are, of course, unknown, the MMS has adopted an analytical methodology which will yield estimates based on current knowledge of the geology of each planning area with consideration of existing engineering and economic constraints. In some planning areas, such as those in the Gulf of Mexico, there is extensive geological and geophysical information on which to base projections about potential resources. Other areas, especially in Alaska, are considered frontier areas because there has been little or no exploration activity and therefore less is known about their potential. It is noteworthy that the possibility of discovering a very large field is greater in frontier areas than in areas where exploration has already located most of the large accumulations. The extent of geological and geophysical data for each planning area is discussed in Appendix E and in Part II.D.

The methodology employed for estimating hydrocarbon resources /1 and economic benefits begins with a detailed assessment of identified hydrocarbon prospects in all OCS planning areas.

There are many uncertainties surrounding the variables used to estimate potential resources associated with these geologic basins. For this reason, a statistical sampling technique is used which allows a wide range of possible inputs for variables such as prospect area extent, zone thickness, oil recovery factor, etc. Use of this methodology results in a range of possible resource values with an associated probability of occurrence.

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/1 A description of this methodology, which uses a computer model known as PRESTO, can be found in a 1985 MMS report, "Estimates of Undiscovered, Economically Recoverable Oil and Gas Resources for the OCS as of July 1984".

/2 March 1985 estimates include changes from July 1984 estimates to reflect resources expected to be leased in intervening lease sales and changes associated with minor boundary revisions.

-Conditional Economically Recoverable Resources

The estimates of resource potential, such as in Table 1 (estimated as of March 1985), and in Table 6 of Appendix F are called "conditional estimates."/2 This means that the resource estimate results hinge upon the condition that the area is hydrocarbon-prone --that is, at least one prospect in the basin contains economically recoverable hydrocarbons. The term "economically recoverable oil and gas resources" refers to the amount of recoverable resources in accumulations sufficiently large that they can be produced at a profit; that is, the revenues from the oil and gas produced cover the costs of development and production, as well as royalties and taxes, while allowing a normal rate of return. Table 6 in Appendix F shows conditional estimates as of Mid-1987 to account for the reduction in resource availability from the Proposed Program 15 subarea deferrals and from resources expected to be leased in sales scheduled to be held between the time that conditional resources were estimated and the beginning of the 5-year program.

Due to inherent uncertainty of estimating undiscovered resources, especially in frontier areas, a range of estimates has been used. To represent the low end of the range, an estimate is given for which there is a 95 percent probability of that amount or more occurring. The high estimate reflects a 5 percent probability of that amount or more occurring. A conditional mean estimate is the average amount one would expect to find if at least one of the prospects in the area contained economically recoverable accumulations of hydrocarbons.

The conditional estimates are important to understanding the ultimate potential of an individual area should future drilling prove that the identified basins contain hydrocarbons. These conditional resource estimates help explain why certain companies are at times willing to take seemingly extraordinary risks by investing in unexplored or high-cost areas. These companies are projecting that sufficient resources exist in the tracts evaluated to provide economic returns which will justify the risks of investing in that area. The conditional estimates are also useful for analyzing potential environmental consequences associated with hydrocarbon development (as was done for the EIS prepared for this 5-Year Program) since the environmental risks are non-existent if the area is not hydrocarbon-prone. In other words, if industry invests in a planning area which proves to contain no hydrocarbons, there will be no environmental consequences of development and the only loss would be the opportunity costs associated with the exploration investments and lease sale planning.

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/1 Note that this risk factor is related to hydrocarbon potential of the entire planning area and is not the same as geologic basin and prospect risk (dry hole risk), which is taken into account in the determination of the conditional resource estimates. (See 1985 MMS report, "Estimates of Undiscovered, Economically Recoverable Oil and Gas Resources for the OCS as of July 1984".)

Table 1

Ranges of Conditional Estimates of Unleased Undiscovered Economically Recoverable Oil and Gas Resources as of March 1985/1

| | Conditional Oil (BBO)/2 | | | Conditional Gas (TCF)/3 | | |
|---|---|---|---|---|---|---|
| Planning Area | 95% Case | Mean Case | 5% Case/4 | 95% Case | Mean Case | 5% Case/4 |
| Central Gulf of Mexico | .95 | 2.66 | 4.97 | 7.57 | 20.64 | 36.53 |
| Western Gulf of Mexico | .45 | 1.69 | 3.31 | 7.23 | 22.61 | 41.05 |
| Eastern Gulf of Mexico | .03 | .36 | 1.48 | .04 | 1.63 | 8.88 |
| Southern California | .44 | .89 | 1.46 | .64 | 1.30 | 2.00 |
| Northern California | .15 | .42 | .76 | 1.17 | 1.86 | 2.48 |
| Central California | .08 | .30 | .59 | .16 | .56 | 1.08 |
| Washington-Oregon | .04 | .18 | .54 | 2.20 | 3.26 | 3.62 |
| South Atlantic | .36 | .87 | 1.51 | 6.62 | 16.22 | 28.18 |
| Mid-Atlantic | .07 | .24 | .51 | 1.39 | 4.21 | 8.18 |
| North Atlantic | .10 | .26 | .43 | 1.98 | 5.06 | 9.03 |
| Straits of Florida | .01 | .11 | .50 | .27 | 1.13 | 2.88 |
| Navarin Basin | 1.81 | 3.28 | 5.09 | 2.34 | 4.26 | 6.75 |
| Beaufort Sea /5 | .11 | .65 | 1.66 | * | * | * |
| St. George Basin | .37 | 1.12 | 1.98 | 3.42 | 9.24 | 18.04 |
| Chukchi Sea /5 | .96 | 2.68 | 4.88 | * | * | * |
| Gulf of Alaska | .12 | .49 | .86 | 1.60 | 8.00 | 18.26 |
| North Aleutian Basin | .08 | .36 | .76 | .56 | 2.62 | 5.25 |
| Norton Basin | .05 | .28 | 1.02 | .31 | 1.55 | 4.26 |
| Kodiak | .04 | .15 | .26 | .58 | 2.92 | 7.13 |
| Hope Basin | .13 | .17 | .40 | .53 | 1.81 | 4.12 |
| Shumagin | .05 | .05 | .09 | .49 | 1.42 | 2.65 |
| Cook Inlet | .03 | .18 | .40 | .04 | .32 | .69 |

* Negligible

/1 Source: "Estimates of Undiscovered, Economically Recoverable Oil and Gas Resources for the OCS as of July 1984", MMS 1985. These estimates were updated (to March 1985) to reflect resources sold in intervening sales. ~~Revisions to the March 1985 estimates were made to reflect the 15 Proposed~~ Program subarea deferrals plus corrections associated with minor boundary changes in the South Atlantic and Straits of Florida planning areas. See Appendix F Table 6, for further revisions in conditional estimates to account for resources expected to be leased in sales scheduled before the beginning of the 5-Year Program.

/2 BBO = Billion barrels of oil

/3 TCF = Trillion cubic feet of gas

/4 Due to the inherent uncertainty of estimating undiscovered resources, a range of estimates has been used. To represent the low end of the range, an estimate is given for which there is a 95 percent probability of that amount or more occurring. The high estimate reflects a 5 percent probability of that amount or more occurring. The conditional mean estimate is the average amount one would expect to find if at least one of the prospects in the area contained economically recoverable hydrocarbons.

/5 In the Chukchi Sea and Beaufort Sea planning areas, water depth of 200 feet is considered to be the limit of current arctic production and development technology. Based on current cost/price relationships and foreseeable technological advances, the conditional mean gas resources estimated to exist are assumed to be noneconomic.

Note that the estimates of the conditional resources for the Proposed Final Program (See Table 1 of SID and Table 6 of Appendix F) reflect resources remaining in planning areas after excluding the 15 subareas proposed for deferral in the Proposed Program.

that an area contains hydrocarbons is known as the marginal probability and should only be applied directly to the conditional mean estimate. The marginal probability varies by planning area and is based on a quantitative assessment of relevant factors by the senior staff of MMS geologists, geophysicists, and engineers.

The estimates of risked economically recoverable estimates for each planning area are displayed in Appendix F, Table 6.

The impact on resource estimates of factoring in the marginal probability of hydrocarbon occurrence is to greatly reduce the estimates for frontier areas. This is appropriate when analyzing "expected" values for the economic analysis that will be used to make relative comparisons among the very diverse OCS planning areas. The risked numbers therefore provide the better guide for determining the timing and frequency of leasing in one area compared to other planning areas.

In deciding if leasing would be economically appropriate in any particular planning area, however, the conditional numbers--along with the assessment of industry interest--provide an important signal. This is the case because the conditional numbers reflect potential, which reflects the fundamental purpose for leasing--to locate undiscovered resources. If industry drills and explores an entire area and discovers oil and gas, the potential recoverable resource is best measured by the range of conditional values, not the "risked" estimate (i.e., the marginal probability becomes 1.00 and therefore no longer deflates the conditional estimate). This is the reason for using conditional estimates when discussing potential environmental consequences in the EIS.

-Leasable Resources

The estimates of both conditional and risked economically recoverable resources do not take into account costs incurred in searching for oil and gas, primarily exploratory drilling and lease acquisition expenses. As a consequence, some unexplored prospects with estimated small amounts of economically developable resources will be uneconomical to explore. The potential payoff will be insufficient to warrant the investment in exploratory drilling, given the risk of finding no oil or gas. Such prospects would not receive a bid based on this assessment of their value. In order to provide the Secretary with aggregate estimates of these oil and gas resources and net economic values likely to be influenced by decisions relating to the new 5-Year Program, a new category of resources called "leasable resources" has been defined. Leasable resources are those in prospects that are sufficiently attractive economically to be leased and explored by private firms.

Leasable resources are estimated as follows. An assessment is conducted of each prospect to determine its (risked) economic value at the time of sale to both the lessee and to the Nation as a whole. If the private value (after tax net present value to the lessee), as estimated by MMS, is found to be greater than zero, then the economically recoverable resources associated with the prospect are considered leasable. If the private value of the prospect is zero or less, then the entire amount of the prospect's economically recoverable resources are deemed to be unleasable at the time of sale for the given economic assumptions.

Thus, the estimate of leasable resources in a planning area is the sum of economically recoverable resources associated with prospects calculated by MMS to be worth acquiring, i.e., those with positive private values. /1

The estimates of leasable resources as of mid-1987, are somewhat understated because resources which may become leasable after mid-1987, due to possible real oil price growth, are not factored into the estimates. /2

Table 2 contains the estimates of leasable resources for each of the planning areas. The basic analysis is framed by a low and high case. In the low case, the price of oil in 1984 (at the start of the analysis for this program) is assumed to be $14 per barrel. In the high cases, the comparable price is assumed to be $29 per barrel. The variations in prices were analyzed for their effects on the risked mean economically recoverable resource estimates from March 1985. The leasable resource estimates reflect resources remaining in the planning area after accounting for 1) projected leasing in sales appearing on the current OCS sale schedule through mid-1987, and 2) 15 subarea deferrals specified in the Proposed Program./3 As Table 2 shows, the Central and Western Gulf of Mexico areas are estimated to have more resource potential in acreage unleased as of 1987 than all the other planning areas combined. The Southern California planning area ranks next with considerably more resources than any other planning area. Significant changes in the resources occur in certain

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/1 The resource estimates were prepared using assumptions (prices, price growth, discount rates, etc.) developed for the 5-Year Program analyses. These estimates may not reflect the economic parameters and assumptions used for upcoming sale-specific analyses, and may not be appropriate for sales scheduled prior to the beginning of the new 5-Year Program (i.e., prior to mid-1987).

/2 Estimates of leasable resources obviously may differ among evaluators because of different expectations of resources, prices, and costs. Moreover, an evaluator's conclusion that a prospect contains leasable resources does not ensure that the evaluator will bid on those resources. The reason could be due to capital constraints, a large inventory of undrilled tracts, or simply that the Government's minimum bid requirement exceeded the evaluator's estimate of private value.

/3 These further refinements in resource estimates serve to exacerbate the inherent uncertainty of resource projections. The estimates will vary not only with different geologic and economic assumptions, but also with different assumptions about upcoming sales, resources projected to be leased in these sales, and which subareas will be deferred from the program.

Table 2



Sensitivity of Leasable Resource Estimates to the Starting Oil Price /1

| Planning Area /2 | Leasable Resources (MMBOE)/3 Low Price | High Price |
|---|---|---|
| Western Gulf of Mexico | 3,790 | 4,630 |
| Central Gulf of Mexico | 3,930 | 4,110 |
| Southern California | 380 | 820 |
| Navarin Basin | * | 790 |
| South Atlantic | 250 | 770 |
| Eastern Gulf of Mexico | 180 | 470 |
| Northern California | 180 | 410 |
| Beaufort Sea /4 | * | 310 |
| Mid-Atlantic | 90 | 230 |
| Central California | 120 | 230 |
| St. George Basin | * | 260 |
| Washington-Oregon | 50 | 60 |
| North Atlantic | 10 | 70 |
| Straits of Florida | * | 10 |
| Chukchi Sea /4 | * | 400 |
| Gulf of Alaska | * | 30 |
| North Aleutian Basin | * | 20 |
| Norton Basin | * | 20 |
| Kodiak | * | * |
| Hope Basin | * | * |
| Shumagin | * | * |
| Cook Inlet | * | * |

* Negligible (estimated to be less than 0.5 million BOE).

/1 Variation in risked estimates of unleased undiscovered oil and gas resources projected to be in leasable prospects ("leasable resources") as of mid-1987. Leasable resources are those which, prior to exploration, are expected to bring positive net benefits to the lessees after deducting royalties, rentals, and taxes. The 1984 starting oil prices were varied from a low price of $14 per barrel to a high price of $29 per barrel. These 1984 prices equate to about $15.75 and $32.50, expressed in 1987 dollars. (Note that prices actually used in the analysis varied by Region to reflect differences in expected quality of OCS crude and transportation costs--see Appendix F). The price estimates used in the analyses were computed from the starting prices assuming a real annual oil price increase of 1 percent per year (and a 5 percent annual inflation rate). An annual real discount rate of 8 percent (13.4 percent nominal) was used to determine 1987 discounted value of all costs and benefits. All calculations of leasable resources, net economic value, and social costs in this SID and its appendices were based on these assumptions unless otherwise specified (see Appendix F).

/2 The planning areas are ordered by "leasable resources" for the $24/bbl. starting price case.

/3 MMBOE = Millions of Barrels of Oil Equivalent. Risked oil and gas resource estimates are obtained by multiplying the conditional mean resource estimate by the marginal probability of the presence of commercial accumulations of hydrocarbons. Resource estimates exclude projections of resources expected to be leased in sales scheduled to be held before the start of this 5-year program, and excludes the potential associated with the 15 subareas proposed for deferral by the Secretary's Proposed Program.

/4 Calculations exclude Beaufort Sea and Chukchi Sea natural gas (see Appendix F).

frontier planning areas as the starting oil price assumption moves from $29 to $14 per barrel because of the high development costs in these areas.

Past and projected leasing in the 1982-1987 period, unpromising exploration results in many areas to date, and lower price expectations have substantially reduced the resource potential remaining to be leased, as compared to the situation anticipated in 1982. This is especially the case in areas such as the Beaufort Sea and the North and Mid-Atlantic areas which were ranked relatively higher in the 1982-1987 program. Most of these areas could show increased potential assuming higher price expectations or positive results from exploration. This is also true of areas where there has been little or no exploration.

Economic Benefits

For each planning area, estimates were made of the net economic value of the prospects containing leasable resources. As explained above, these estimates were based on the hypothetical assumption that all leasable prospects were acquired by private industry in mid-1987 and subsequently explored, developed, and produced over time periods typical of each area and water depth.

In the Proposed Program, the base case estimates of net economic value for each of the planning areas' leasable oil and gas resources assumed a $24 per barrel starting price of oil. Price sensitivity results were incorporated into the net economic value estimates to reflect the great uncertainty in projecting future oil prices. This sensitivity analysis showed how estimates of potential benefits from OCS development will vary depending upon assumptions about future prices.

About the time that the Proposed Program was completed, events in the world crude oil market were driving the market price of oil down to levels not seen since the mid-1970's. Consequently, many commenters recommended that the SID price assumptions be revised downward (see Appendix B, Section B(3)). To provide resource and net economic value information that will reflect an appropriate range of future price scenarios over the development timetable of expected production, the Proposed Final Program analysis was prepared for a wider range in the low and high starting price cases. /1

Additional sensitivity analyses of the net economic value estimates are presented

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/1 Initially, the starting price ranged from $24 to $34 per barrel in the Draft Proposed Program and from $19 to $29 per barrel for the Proposed Program. For the Proposed Final Program, the low and high starting oil price cases used were $14 and $29 per barrel--with further sensitivity analyses at $9 and $34 per barrel. The $14 and $29 per barrel starting prices of oil are expressed in July 1984 dollars, which was when this analysis began. For the analysis, starting prices were escalated for inflation (at 5% annually) and real price growth (at 1% annually) to arrive at future prices for the expected period of production in each planning area. Note that prices used in the analysis varied by Region to reflect differences in expected quality of OCS crude oil and differences in transportation costs--see Appendix F, section VII.D.

in Table 13 of Appendix F to demonstrate the variability of the estimates to changes in assumptions of real price growth (at a 0 percent and 2 percent annual rate) and to changes in assumptions for the real discount rate (to 6 percent from the base case of 8 percent). As can be seen from the sensitivity analysis, the variation in net economic value estimates is much greater when considering these further changes in assumptions.

It should be noted that while this analysis reflects the sensitivity of net economic value to changes in price assumptions it does not incorporate the effects of geologic and economic resource uncertainty conveyed by the ranges of resource estimates. Such a combined range would be even broader than the one presented--so broad, in fact, to be of questionable use for the primary decision options that emerge from this document. It should also be noted that while the variation in net economic value is keyed to alternative starting oil prices, the resulting variation of net economic value is an indication of the variety of uncertainties affecting the leasing program for which quantitative sensitivity measures are not provided (e.g., with respect to resource estimates and the variability of oil and gas prices within the range depicted in Figure 1). Figure 1 graphically approximates the variation in prices which were used in the development of the leasable resources and net economic value estimates (the graph shows real price growth after 1987 and ends in the year 2010 for ease of display). /1 As can be seen from this graph, actual prices (yearly averages) from 1984 to 1986 have been declining (Department of Energy (DOE), refiner acquisition cost of imported crude oil).

These price paths are not projections of future prices, but were chosen to present an appropriate range of possible future prices for consideration by the Secretary. For example, published price projections from a sample of forecasting groups, including those price projections from the DOE National Energy Policy Plan (NEPP), are included in Figure 1 to display how the results of the SID price assumptions track with various price forecasts. Note that some projections were made to 1995, others to 2010. In the years beyond 1995, forecasts from DOE and Data Resources Inc. (DRI) show a sharper rise in expected prices than is assumed in the SID. Obviously, the SID estimates of leasable resources and net economic value are somewhat conservative relative to the results which would be obtained by using assumptions of higher real price growth in later years.

As can be seen with the various price projections shown in Figure 1, there is no clear agreement among forecasting groups as to future price paths. However, it seems that many experts contend that the longer current prices stay relatively low, the more likely it is that real future prices will rebound faster and to higher levels, due primarily to the increased consumer demand for oil brought about by the lower prices. On the other hand, the lesson of the 1980's may well be that the longer oil prices are held at relatively high levels by

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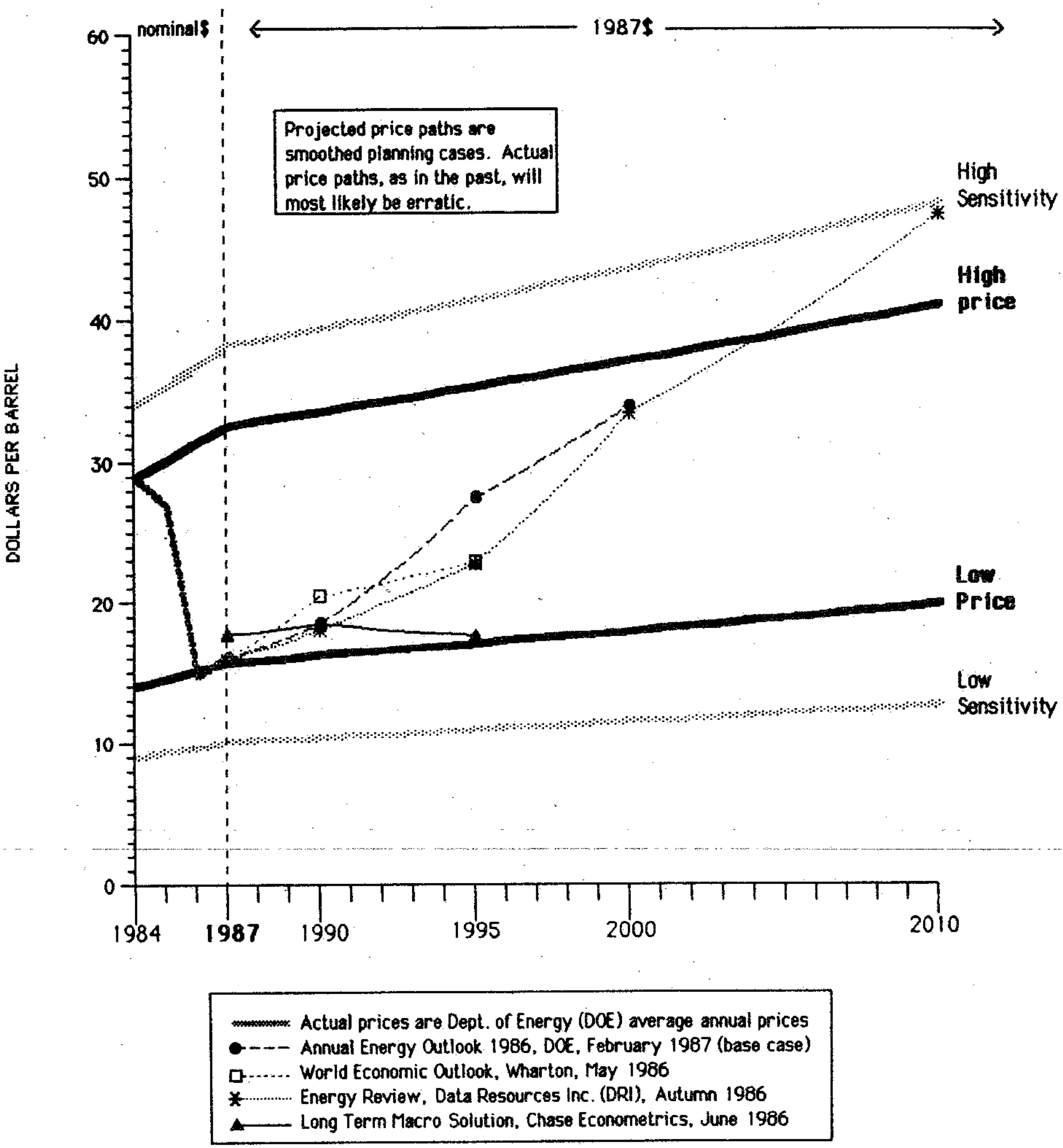
/1 Note that prices actually used in the analyses varied by region to reflect differences in expected quality of OCS crude and differences in transportation.

FIGURE 1

OIL PRICE SCENARIOS FOR THE 5-YEAR PROGRAM




The variation in oil prices used to estimate leasable resources and net social value for the 5-Year OCS Leasing Program is depicted by the bold lines. The $14 and $29 starting prices reflect a range of weighted average FOB prices of U.S. imports of oil at the time when the analysis began in 1984. These prices are then adjusted for real price growth and inflation (nominal price growth) to arrive at mid-1987 starting prices of oil for the 5-Year Program. Thereafter, prices are adjusted assuming a 1% annual real price growth. The shaded lines reflect a wider range of real price growth assumptions for sensitivity analysis. Projections from price forecasting groups are included to show how the 5-Year Program price scenarios track with various forecasts. These forecasts have been converted to $1987 using comparable GNP deflator asssumptions of between 3 and 5 percent annually.

restricted production of OPEC resources, the more likely it is that prices will fall.

The OPEC producers with massive amounts of low-cost resources set prices in the 1970's that were so high that the resulting increases in other sources of oil production and decreases in demand reduced their market share and sales. Recently, they have been trying to regain their share of world production by underpricing other producers and expanding their production to meet the demand for oil.

Once a substantial share of world demand is being met by production from low-cost producers, any cutback in their production could well cause oil prices to rise rapidly unless there are sufficient low-cost substitutes readily available.

An important point to note when thinking about these price scenarios is that production revenues from most 5-year program leasing will not be realized until many years in the future. For this reason, future prices assumed in the analyses will be the major influence on how much resource is projected to be leasable and the associated net economic value of those resources. The stipulated starting prices are simply a convenient way to index the entire vector of relevant future prices.

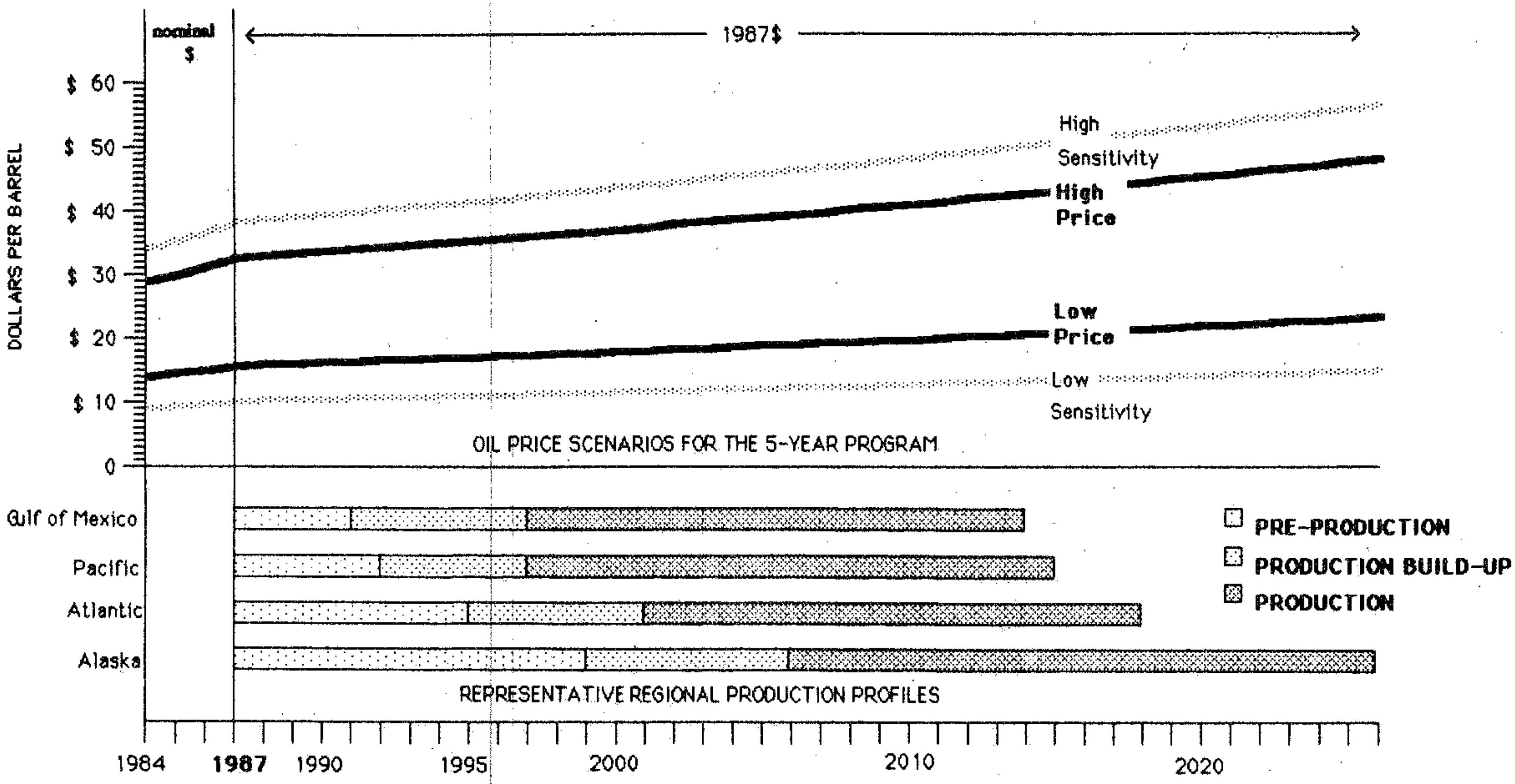
The lead-times needed to bring new offshore fields into production are substantial and will vary by region. Once a sale is scheduled in a 5-year program, the pre-sale process leading up to holding the sale can take over 2 years. Several more years are needed by industry to evaluate leases, determine whether drilling is warranted, and drill exploratory and delineation wells. The time elapsed from leasing to initial production can extend from about 4 to 12 years, depending on operating conditions in the different regions. Figure 2 includes a graph of representative regional production profiles showing the "earliest" years of production, the number of years for production build-up, and years of possible production. When comparing the production profiles to the price scenarios for the timeframe of production in the different regions, it can be seen that future price expectations are the relevant component of the economic analyses.

A further comparison with Figure 1 will reveal that some forecasting groups are predicting future price paths that greatly exceed our high price case for the relevant timeframes. Therefore, a range of scenarios should be considered when interpreting the quantitative analyses over the entire range of prices. Depending upon the future price scenario that one expects, even the quantitative results using the high price case may be viewed as too conservative. The resource and economic benefits results for the "high price sensitivity" case, or for the case of higher real price growth assumptions, may be more appropriate. (See Appendix F, Table 13.)

The low price case assumptions, when considering the current projections, may well underestimate future prices. In the Department of Energy's most recent short-term energy outlook (July 1986), the refiner acquisition cost of crude oil for 1987 is projected to average $16.30 per barrel, up from the average of $14.70 projected for 1986. Longer term price projections (see Figure 1) are

**FIGURE 2**

COMPARISON OF PRICE SCENARIOS
WITH REGIONAL PRODUCTION PROFILES




A comparison of oil price scenarios with production profiles from 1987 through 2026 shows the prices used in the SID analysis for the expected times of production, assuming all leasable resources are sold in 1987. As can be seen from this comparison, it is the future prices (not today's prices) which ultimately determine the estimates of resources and economic value.

A further comparison with price forecasts shown in Figure 1 shows that the 5-year program range of prices examined in the short-term is consistent with those projections of selected forecasting groups. In later years, over the timeframes of production, the SID conservative assumptions of constant low real price growth will tend to understate the value of resources relative to the results which would be obtained from these other price forecasts.

for continued increases in the rate of real price growth, resulting in a price path diverging widely from the low price case scenario of this analysis.

Results of Economic Benefits Analysis

Table 3 shows the variation of net economic value estimates (1987 dollars) indicating the great variability in the values over a $15 starting price spread. Table 4 shows these same results on a per barrel basis. The sum of the net economic value estimates for all planning areas show a range of potential economic benefits to the economy from $19 to $84 billion as one moves from the low case to the high case (hypothetically assuming that all leasable resources are sold in mid-1987). See Part III.A. for discussion of value for Program Alternatives.

The high case estimates for certain Alaska areas in Table 3 indicate the potential profitability of oil and gas with the higher price scenario in these locations. Results for the low starting oil price case show that the Gulf of Mexico and California OCS areas continue to have leasable resources. Additionally, certain other planning areas--in the Atlantic, and Washington-Oregon planning areas--were found to contain some leasable resources when accounting for lower production cost estimates from reduced demand for drilling services associated with declining oil prices.

In addition to the total net economic value estimates for leasable resources in each planning area, estimates were prepared showing the distribution of these undiscovered resources in each area by dollar categories of the net economic value. Table 5 shows the leasable oil and gas resources in each of three net economic value categories: $0.00 to $3.00; $3.00 to $6.00; and $6.00 to $10.00 per barrel for the low ($14 per barrel) and high ($29 per barrel) starting price cases. These disaggregated estimates of resources allow more detailed consideration of the economic characteristics of the oil and gas resources within each area. For example, in the high price case, the results indicate that the Western and Central Gulf have substantial resource potential in the highest net economic value categories. This means that there will be a substantial number of good investment opportunities to be found there even with a large drop in the price of oil.

Similarly, the three California areas, and the Eastern Gulf of Mexico and the Washington-Oregon planning areas, also have significant resource potential in the highest value categories for the high price case. The estimates of resource potential in the upper value categories means that some leasing and investment in exploration will likely be worthwhile over the entire range of prices examined. On the other hand, the large proportion of resources in the low value category in planning areas such as the Navarin Basin, St. George, and Beaufort Sea make these areas highly sensitive to a drop in oil prices.

Estimates were also made of the effect of delaying leasing and the investments leading to production in each area. As explained in Appendix F, if oil prices are expected to increase at a constant annual rate, the highest-cost, lowest-valued prospects are expected to increase in net economic value enough to yield benefits from delays while the lowest-cost, highest-valued prospects are

Table 3

Sensitivity of Net Economic Value Estimates to the Starting Oil Price /1

| Planning Area /2 | Estimated Net Economic Value (Millions of 1987 Dollars) Low Price | High Price |
|---|---|---|
| Central Gulf of Mexico | $ 9,432 | $ 31,236 |
| Western Gulf of Mexico | 7,201 | 31,484 |
| Southern California | 1,566 | 6,336 |
| South Atlantic | 400 | 3,157 |
| Northern California | 390 | 2,460 |
| Eastern Gulf of Mexico | 180 | 2,397 |
| Navarin Basin | * | 2,054 |
| Central California | 187 | 1,430 |
| Mid-Atlantic | 90 | 897 |
| St. George Basin | * | 754 |
| Washington-Oregon | 130 | 486 |
| Beaufort Sea /3 | * | 682 |
| North Atlantic | 17 | 245 |
| Straits of Florida | * | 55 |
| Chukchi Sea /3 | * | 600 |
| Gulf of Alaska | * | 36 |
| North Aleutian Basin | * | 26 |
| Norton Basin | * | 34 |
| Kodiak | * | * |
| Hope Basin | * | * |
| Shumagin | * | * |
| Cook Inlet | * | * |

* Negligible (estimated to be less than 0.5 million of $1987)

/1 Variation in estimated net economic value of unleased undiscovered oil and gas resources in leasable prospects as of mid-1987. The 1984 starting oil prices were varied from a low price of $14 per barrel to a high price of $29 per barrel. (See text and footnote 1 of Table 2 for further explanation of price assumptions). Net economic value is the revenue obtained by the sale of oil and gas less the exploration, development, production, and transportation costs necessary to bring the oil and gas to market. Estimates of net economic value for resources projected to be leased in sales scheduled to be held before the start of this 5-year program are not included in these estimates.

/2 The planning areas are ordered by net economic value for the $24/bbl. starting price case.

/3 Net economic value calculations exclude Beaufort Sea and Chukchi Sea natural gas (see Appendix F).

Table 4

Range of Average Net Economic Value Per BOE For Leasable Resources /1

| Planning Area | Average Net Economic Value ($/BOE) Low Price | High Price |
|---|---|---|
| Central Gulf of Mexico | $ 2.40 | $ 7.60 |
| Western Gulf of Mexico | 1.90 | 6.80 |
| Southern California | 2.60 | 6.10 |
| South Atlantic | 1.60 | 4.10 |
| Northern California | 2.60 | 6.60 |
| Eastern Gulf of Mexico | 1.00 | 5.10 |
| Navarin Basin | * | 2.60 |
| Central California | 2.00 | 6.90 |
| Mid-Atlantic | 1.00 | 3.90 |
| St. George Basin | * | 2.90 |
| Washington-Oregon | 2.60 | 8.10 |
| Beaufort Sea | * | 2.20 |
| North Atlantic | 1.70 | 3.50 |
| Straits of Florida | * | 5.50 |
| Chukchi Sea | * | 1.50 |
| Gulf of Alaska | * | 1.20 |
| North Aleutian Basin | * | 1.30 |
| Norton Basin | * | 1.70 |
| Kodiak | * | * |
| Hope Basin | * | * |
| Shumagin | * | * |
| Cook Inlet | * | * |

* Negligible

/1 BOE - Barrels of Oil Equivalent
See footnote 1, Table 2, for price and discount rate assumptions.
Data taken from Appendix F, Table 8.

Table 5

Distribution of Risked Economically Recoverable Resources
by Net Economic Value Per Barrel Category
for the Low and High Price Cases

(Millions of barrels of oil equivalent (BOE))

| | Recoverable but/1 not Leasable | | Leasable Resources /2 Net Economic Value per barrel Category /3 | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | Below $3.00 | | $3.00 to $6.00 | | $6.00 to $10.00 | |
| Planning Area | Low | High | Low | High | Low | High | Low | High |
| Central Gulf of Mexico | 640 | 460 | 2,450 | * | 1,480 | 110 | * | 4,000 |
| Western Gulf of Mexico | 840 | * | 3,790 | * | * | 540 | * | 4,090 |
| Southern California | 740 | 300 | 180 | * | 200 | 440 | * | 380 |
| South Atlantic | 690 | 170 | 250 | 290 | * | 480 | * | * |
| Northern California | 270 | 40 | 180 | * | * | 180 | * | 230 |
| Eastern Gulf of Mexico | 400 | 110 | 180 | 50 | * | 210 | * | 210 |
| Navarin Basin | 1,090 | 300 | * | 270 | * | 520 | * | * |
| Central California | 130 | 20 | 120 | * | * | 120 | * | 110 |
| Mid-Atlantic | 900 | 760 | 90 | 120 | * | 110 | * | * |
| St. George Basin | 610 | 350 | * | 260 | * | * | * | * |
| Washington-Oregon | 100 | 90 | 10 | * | 40 | 10 | * | 50 |
| Beaufort Sea | 460 | 150 | * | 310 | * | * | * | * |
| North Atlantic | 340 | 280 | 10 | 40 | * | 20 | * | 10 |
| Straits of Florida | 20 | 10 | * | * | * | 10 | * | * |
| Chukchi Sea | 540 | 140 | * | 400 | * | * | * | * |
| Gulf of Alaska | 150 | 120 | * | 30 | * | * | * | * |
| North Aleutian Basin | 90 | 70 | * | 20 | * | * | * | * |
| Norton Basin | 70 | 50 | * | 20 | * | * | * | * |
| Kodiak | 30 | 30 | * | * | * | * | * | * |
| Hope Basin | 10 | 10 | * | * | * | * | * | * |
| Shumagin | 10 | 10 | * | * | * | * | * | * |
| Cook Inlet | 10 | 10 | * | * | * | * | * | * |

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* Negligible (estimated to be less than 0.5 million BOE).

/1 Recoverable resources are those that would be profitable for a lessee to produce, given that they have already been discovered.

/2 See definition in footnote 1 to Table 2. The data in Table 4 are taken from Table 7 in Appendix F.

/3 Note that where leasable resource estimates appear to decline at higher prices, the resources have actually been reclassified into higher net economic value categories.

expected to decrease in net economic value if investments are delayed. Estimates of the simple average annual dollar changes in net economic value per barrel were calculated assuming that real oil prices increase at 1 percent per year. It is important to note that these are average figures for an entire planning area which do not display the range of values which would be seen if individual prospects were examined.

Table 6 of the SID displays the results of applying the per barrel delay costs for the \$14 and \$29 per barrel price cases to the leasable resources estimated for each planning area. The results yield estimates of the average (NEV per barrel) annual costs of delaying leasing for all leasable resources in each planning area. For most cases, in most planning areas, a delay in leasing would be expected to result in an overall decline in net economic value for the planning area. Comparing the results in Table 6 with those in Table 4 demonstrates that areas with more low cost, high-valued resource prospects such as the Gulf of Mexico and Pacific areas tend to have higher costs of delay. Areas with predominantly lower valued resource prospects have lower delay costs.

To test the sensitivity of the delay cost analyses to changes in the assumptions about real price growth and the discount rate, a 2 percent real price growth and a 6 percent discount rate assumption, were also examined. The results are displayed in Table 9 of Appendix F.

### Assessing the Results of the Resource Estimates and Net Economic Value Analysis for Decision Options

Decision options on scheduling sales and subarea deferrals will be treated further in Part III. While the 5-year program decisions call for a consideration of all section 18 factors, it is worth focusing on how resource and net economic value data can contribute to that process.

As explained above, a low or negligible resource or economic value estimate should not necessarily lead to the conclusion that the planning area has no resource potential. Rather, the area should be viewed as likely to have relatively less potential compared to certain other planning areas for that particular set of price and cost assumptions.

For example, in the Chukchi Sea planning area, in the low price case, the estimate of leasable resources is negligible. This is one piece of information to consider in comparing planning areas for the decision on sale scheduling but is not the entire picture. Resource estimates for the higher price cases are substantially larger. It is also important to note that the Chukchi Sea planning area has a sizable mean conditional resource estimate and a wide range of potential resources. Results for the economically recoverable resources for the 5 percent probability case indicate that there is a 1 in 20 chance that the planning area could contain up to 5 billion barrels of oil, if the area proves to be hydrocarbon-prone (See Table 1). Additionally, industry interest rankings show that this planning area rates fairly high in interest and potential relative to many other planning areas. Thus, the Secretary needs to consider the range of estimates reflecting various future price expectations and the range of conditional resource estimates which indicates the hydrocarbon potential of the planning areas (see Table 13.3).

Table 6

Average Dollar Change in Net Economic Value Per Barrel for Leasable Resources from a One-Year Delay in Leasing, Showing Variation by Starting Oil Price /1

| Planning Area | Change in Net Economic Value (per barrel) Low Price | High Price |
|---|---|---|
| Central Gulf of Mexico | $ -.13 | $ -.46 |
| Western Gulf of Mexico | -.09 | -.40 |
| Southern California | -.14 | -.34 |
| South Atlantic | -.07 | -.21 |
| Northern California | -.14 | -.37 |
| Eastern Gulf of Mexico | -.01 | -.29 |
| Navarin Basin | * | -.11 |
| Central California | -.09 | -.40 |
| Mid-Atlantic | -.02 | -.19 |
| St. George Basin | * | -.12 |
| Washington-Oregon | -.13 | -.40 |
| Beaufort Sea | * | -.10 |
| North Atlantic | -.08 | -.16 |
| Straits of Florida | * | -.31 |
| Chukchi Sea | * | -.09 |
| Gulf of Alaska | * | -.02 |
| North Aleutian Basin | * | -.02 |
| Norton Basin | * | -.04 |
| Kodiak | * | * |
| Hope Basin | * | * |
| Shumagin | * | * |
| Cook Inlet | * | * |

* These planning areas are estimated to have neglible amounts of leasable resources for the subject price case. Cost of delay for these areas has been analyzed further in Appendix F.

/1 See footnote 1, Table 2, for price and discount rate assumptions. Data taken from Appendix F, Table 9.

The average dollar change estimates above reflect the potential loss in net economic value per barrel from a one-year delay in leasing. The same estimates for subsequent one-year delays could be inferred to be approximately the same. However, due to the effects of discounting, the analysis for dollar changes associated with multiple year delays would result in lower average annual values.

The results of the analysis are an important indication of lower economic potential in the OCS under lower price assumptions. Nonetheless, it must be remembered that the 5-Year Program analysis and the options developed for scheduling lease sales covers a wide range of future price uncertainty and primarily a qualitative assessment of other considerations, such as national security, industry interest, and equitable sharing of development costs and benefits. Moreover, the 5-year program scheduling decisions will be made in 1987 for sales to be held in 1987 through 1992. Hence, it would be unwise to limit our planning for leasing in the period 1987 through 1992, and the associated exploration and development for the ensuing 30 years, by concentrating only on the current state of economic and geologic variables, e.g., by structuring a program based on the low price scenarios.

If the program were based on lower prices, and prices subsequently rose more than expected, it would take two or more years to revise the schedule to add sales. On the other hand, it is a relatively simple matter to cancel a sale if prices cause industry interest to wane. (This was done recently for sales in Alaska and in the Atlantic.) The costs associated with canceling a sale are those costs of proceeding with the initial steps in the leasing process, such as contracts for studies and Environmental Impact Statement preparation, and geological and geophysical data acquisition.

After the economic analysis for the SID was completed, the President signed into law the Tax Reform Act of 1986, which includes changes in the tax laws which would affect taxes paid by oil and gas producers. The major features of the new law, as they relate to the oil and gas industry, are a reduction in the marginal tax rate from 46 to 34 percent; repeal of the investment tax credit; lengthening of the average time required to depreciate capital items; and a limitation on the use of expensing intangible drilling costs.

For purposes of assessing net economic value to the Nation of OCS oil and gas production, changes in taxes are not treated as causing changes in public benefits unless they promote changes in private decisionmaking. Otherwise, changes in taxes merely redistribute the project benefits between the private and public sector.

Typically, changes in corporate taxes primarily influence private decisions on marginal projects even though the profitability of all other ventures may be affected. Accordingly, it can be inferred that the new tax act may somewhat change the magnitude of leasable resources without substantially affecting the public value of the original set of leasable prospects. In order to assess these effects, a preliminary evaluation was made for selected prospects. Conclusions from this assessment are discussed in Part VII.D. of Appendix F.

In assessing the results of the analysis, it should be recalled that there is a high degree of uncertainty surrounding resource estimates, costs, technology, economic parameters, and therefore each area's net economic value. These estimates reflect a detailed, thorough, quantitative analysis by MMS professionals, but the estimates are subject to significant limitations. (See Appendix F and Appendix S.) Prudent use of these estimates should be limited to drawing general distinctions among planning areas.

## II.E.2 Estimated Social Costs

### Background

In compliance with California v. Watt (I) and (II), a quantitative analysis was made of some of the potential social costs which might be associated with development of the recoverable hydrocarbon resources in each of the OCS planning areas. While the estimated social costs are calculated on the basis of the development of the resources of each of the planning areas, in the aggregate they should be viewed as costs to the Nation as a whole. This is so since not all of the costs resulting from development of the resources in a planning area are necessarily borne by the residents living near the area.

Focusing on costs to the Nation as a whole is also necessary to provide the comparability among areas necessary to the performance of the required cost-benefit analysis since the net economic value estimates measure benefits to the Nation as a whole. The comparability of costs and benefits is also achieved by basing the social cost analysis on the leasable resource estimates used in the net economic value analysis (see Table 2). It should be noted that leasable resources are calculated on a "risked" basis--i.e., incorporating an estimate of the probability of occurrence of potential effects as well as their magnitude. The EIS, on the other hand, is based on "conditional" resource estimates, which are not modified by a risk factor.

A vitally important reason that the estimates of social costs are likely overstated is that development of the United States' OCS oil and gas resources is conducted in an increasingly safe and environmentally sound manner. The program has an excellent record of few personnel and mechanical failures which have resulted in environmental damage or adverse coastal zone impacts (see Appendix Q). While the calculations are based on historical data, advances in technology have lowered and can be expected to continue to lower the chance of such damage and impacts. However, if there were an increase in activities in areas with harsh operating conditions, that trend might change. The substantial OCS oil and gas environmental studies program of the Department of the Interior (DOI) is continuing to shed light on where and how damages may occur and how they can be prevented. The regulatory and operating procedures of the DOI have mitigated and will continue to mitigate many of the potential damages (see Appendix Q).

Furthermore, the OCS Lands Act Amendments of 1978 established funds to compensate those who are adversely affected in the event that OCS oil spill-related damage or commercial fishing gear losses occur. While not taken into account in the computation of social costs, those compensation payments have been used to compute the distribution of costs discussed in Part II.C. Finally, when uncertainty was encountered in making individual social cost estimates, a decision was made to adopt conservative assumptions that may tend to result in an overestimation of those costs.

A full description of all the potential costs estimated for this analysis is presented in Appendix G. The introduction and summary to Appendix G also provides a more detailed explanation of the analytical approach, the meaning of social costs, the method of calculation, the data sources used, and the reliability of estimates.

## Social Costs

Social costs are market and non-market valued environmental and socioeconomic costs which are not normally included in the costs of operations involved in OCS oil and gas exploration, development, production, and transportation.

In this analysis, social cost estimates are computed for potential large oil spills (1,000 barrels or more), small spills (under 1,000 barrels), spill control and cleanup costs, commercial fishing losses, recreation losses, potential ecological damages, real property losses, legal expenses, subsistence losses, the value of oil spilled, research expenses, and other costs. Estimates were also made for the following potential non-oil spill costs: potential air quality losses; wetlands losses; losses resulting from physical conflicts between commercial fishing and OCS oil and gas operations; and infrastructure costs.

Since social costs are costs to the Nation as a whole, they are measured net of the social costs avoided because OCS oil reduces the quantity of oil imported and hence reduces spills of imported oil. Thus, Appendix G first calculates gross social costs and then subtracts from that figure the costs avoided because oil imports are reduced in order to calculate the net social costs displayed in Table 7.

Of the potential OCS oil and gas damages that could occur, the quantitative analysis was restricted to those for which cost data (in dollars) exist and, in the professional judgment of the staff of the MMS could be adapted to the analysis. Additional information about these potential damages as well as information about other potential quantifiable damages and unquantifiable damages which were not included in this analysis will be described in the EIS and elsewhere in the SID. These descriptions, along with this social cost analysis, will allow consideration of variations in potential environmental damage and adverse coastal zone impacts from planning area to planning area in selecting the timing and location of leasing.

## Comparison of the New Analysis and the 1982 Analysis

The analysis of social costs updates, refines, and extends a similar analysis undertaken in formulating the 1982 5-Year OCS Leasing Program. The current analysis reflects three major improvements: (1) updated and considerably lower estimates of unleased oil and natural gas resources; (2) substantially lower tanker oil spillage rates in general, and especially in U.S. waters; and (3) refinements in the analysis. The net effect of these changes is to increase the new estimated potential social costs of developing oil and gas resources in the Central and Western Gulf of Mexico and to decrease the estimated costs of developing hydrocarbon resources in other areas as compared to the 1982 program analysis.

Appendix G demonstrates a number of fundamental differences between the total and per-barrel social costs estimated in connection with the 1982 proposed 5-year leasing program and the social costs estimated for consideration in the formulation of the new program. Estimated oil spill and non-spill costs per unit of production in general are considerably less in this analysis than those estimated in 1982. Lower oil spillage rates because of improved tanker and pipeline safety records, as well as lower resource estimates and the use of refined economic concepts explain the lower costs in this analysis as compared to the 1982 results. The major differences between this analysis and the 1982 analysis are explained in section H of Appendix G.

## The Social Cost Analysis

Social cost estimates are a measure of the total costs accruing to the Nation that may be expected from the proposed OCS oil and gas development in each planning area. The social cost estimates encompass environmental or external costs and private costs not considered in the analysis of the net benefits of developing OCS oil and gas resources. The most important private costs considered are oil spill cleanup and control costs. Whether these costs will actually occur is uncertain and, therefore, they should be regarded as potential costs.

Estimates of the potential costs in each category of damage were based on data and judgments derived from the results of a literature search, the analysis of relative environmental sensitivity and relative marine productivity (see Part II.B.3 and Appendix I), knowledge of the value of other uses of the sea, the estimated amount of oil and gas production, the chance of spills reaching shore, the likelihood of resulting damage in each area, information received in response to requests for comments (summarized in Appendix B), and a number of other factors.

The social cost estimates are summarized in Table 7. Table 7 shows that the estimates associated with the development of all the leasable resources in each planning area range from a total estimated social cost of $32.5 million for the Central Gulf of Mexico to a total social cost of less than $0.5 million for several Alaskan OCS areas, the Straits of Florida, and Washington-Oregon.

Estimated social costs vary considerably depending on the planning area. For instance, recreation losses caused by oil spills are estimated to be relatively low in the Alaskan areas but higher elsewhere. Based on an analysis of commercial fishing landings statistics published by the National Marine Fisheries Service and the State of Alaska, commercial fishing losses per barrel of oil spilled are estimated to be high in the North Atlantic and Central Gulf of Mexico and moderate to low for other areas. Also, it is estimated that per-barrel subsistence losses may be significant in some areas of Alaska, but they are projected to be negligible outside Alaska. The estimated unit cost of oil spill control and cleanup is considerably higher for Alaskan areas vs. the "lower 48" (see Appendix G).

Losses per billion barrels of oil equivalent (BBOE) due to air pollution were judged to be negligible in all the Alaskan areas except Cook Inlet, where they were estimated to be low. Air pollution losses without mitigation in areas of the contiguous 48 States are negligible except for the Southern California area and the Central Gulf of Mexico area, where they are estimated to be low, due in large part to the concentrated coastal population and the topographical features and climate of these areas. (see Appendix G).

Generally speaking, there is a direct relationship between a planning area's total social cost and the total hydrocarbon resources estimated to be produced in the area. However, the oil-gas resource composition, the probability of a spill reaching shore, the value of each area's marine resources, and socioeconomic characteristics influence estimated social costs. The relative marine productivity/environmental sensitivity analysis also provides an input to the estimation of social costs while serving as a separate consideration in itself.

Table 7

Range of Estimated Potential Net Discounted Social Costs
Associated with Production of the Estimated Leasable Resources
in Each Planning Area
(In Millions of $ 1987) /1

| | Low | | High |
|---|---|---|---|
| Central Gulf of Mexico | $ 41.8 | - | 42.3 |
| Western Gulf of Mexico | 30.4 | - | 35.8 |
| Southern California | 6.0 | - | 12.3 |
| South Atlantic | 2.1 | - | 5.0 |
| Northern California | 3.6 | - | 6.3 |
| Eastern Gulf of Mexico | 2.8 | - | 5.6 |
| Navarin Basin | * | - | 15.7 |
| Central California | 2.2 | - | 3.6 |
| Mid-Atlantic | 1.1 | - | 2.0 |
| St. George Basin | * | - | 4.4 |
| Washington-Oregon | * | - | .5 |
| Beaufort Sea | * | - | 4.4 |
| North Atlantic | .5 | - | .7 |
| Straits of Florida | * | - | * |
| Chukchi Sea | * | - | 3.2 |
| Gulf of Alaska | * | - | .5 |
| North Aleutian Basin | * | - | * |
| Norton Basin | * | - | .6 |
| Kodiak | * | - | * |
| Hope Basin | * | - | * |
| Shumagin | * | - | * |
| Cook Inlet | * | - | * |

/1 Present value of net discounted social costs is calculated using a discount rate of 8 percent (see Appendix G). The numbers in the range correspond to resource estimates based on a low starting oil price case and a high starting oil price case. The planning areas are ordered for net economic value @ $24/bbl starting oil price for consistency with other tables in this SID. Compare Table 7 with Table 12.1.

* Estimated to be less than $0.5 million.

The social cost per billion barrels of oil equivalent (BBOE) produced is shown in Table 8. The rankings of the areas in terms of costs per BBOE differ from their total cost rankings. In several cases, areas with relatively low estimated recoverable resources have relatively high social costs per BBOE. This result reflects a combination of factors including environmental sensitivity and productivity, high valued commercial fisheries, recreation losses and cleanup costs, particularly for areas where there is a high chance that any spills which occur will reach the shore.

Wetland losses from onshore development related to OCS production, although considerably lower than similar estimates made in 1982, are estimated to be highest for the Central /1 and Western Gulf of Mexico. The key determinants of these estimates are the additional activity estimated to take place in each area, the extent to which existing facilities can accommodate the additional activity, and the effectiveness of governmental permitting requirements in mitigating these potential losses (see Appendix Q).

While social costs measure the estimated cost of producing the area's unleased leasable resources to the Nation as a whole, the estimate does not indicate the distribution of costs among the population. The distribution of such costs is treated in Part II.C, in the discussion of the equitable sharing of developmental benefits and environmental risks.

Because of the uncertainty and difficulties associated with estimating several categories of cost, a sensitivity analysis was carried out to determine the social cost that would be estimated if specific unit costs are presumed to be even higher than the overstated costs used to develop the estimates of social costs presented in Table 7. The results of the sensitivity analysis in Appendix G indicate that while the costs in each planning area are greater than the results presented in Table 7, the ranking of OCS areas by their net social value (see Part II.D of this SID) does not change. This is because: (1) only a subset of all costs (i.e., the largest and most uncertain costs) is assumed to increase; and (2) when individual oil spill costs increase, the social cost savings from backing out imported oil also increase, thereby moderating the net increase in social costs.

In assessing the results of the analysis shown in Table 7, it is important to keep in mind the high degree of uncertainty associated with the estimates. Given the uncertainty of the data on which the analysis was based, and the necessity of heavy reliance on judgment, the social cost estimates should be considered, at best, as an order of magnitude approximation. As such, prudent use of these estimates would make distinctions between differences from area to area only if they are substantially more than an order of magnitude in size (that is, if one estimate is substantially more than 10 times the other).

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/1 The loss of coastal wetlands has been most pronounced in the Central Gulf of Mexico. Current information on the processes causing wetland loss implicates large-scale geologic and oceanographic processes along the Louisiana coast. In comparison to these other forces, OCS-related activities do not appear to have been a significant contributor to the loss of coastal wetlands in this area. (See Appendix G).

Table 8

Estimated Potential Social Costs Per Billion Barrels of Oil Equivalent (BBOE) Associated With Total Production of Leasable Resources Estimated to be in Each Planning Area (In Millions of $ 1987) /1

| Area | Net Costs Per BBOE |
|---|---|
| Straits of Florida | $37 |
| Norton Basin | 30 |
| Cook Inlet /2 | 21 |
| Navarin Basin | 20 |
| North Aleutian Basin | 19 |
| St. George Basin | 17 |
| Gulf of Alaska | 16 |
| Central California | 16 |
| Kodiak /2 | 15 |
| Northern California | 15 |
| Southern Calfornia | 15 |
| Beaufort Sea | 14 |
| Hope Basin /2 | 13 |
| Shumagin /2 | 13 |
| Eastern Gulf of Mexico | 12 |
| North Atlantic | 11 |
| Central Gulf of Mexico | 10 |
| Mid-Atlantic | 9 |
| Chukchi Sea | 8 |
| Washington-Oregon | 8 |
| Western Gulf of Mexico | 8 |
| South Atlantic | 7 |

/1 Present value of net social costs is calculated with a discount rate of 8 percent for both the low and high starting oil price cases. Results for the high price case are presented because 12 planning areas are estimated to have no leaseable resources for the low price case (see text and Footnote 1 of Table 2 for a discussion of price assumptions). The variation of the BBOE social costs for most planning areas is quite constant across the low price to high price cases for resource estimates. See Appendix G for net social costs per BBOE for planning areas where subarea deferral proposals are being considered.

The Straits of Florida has the highest net social costs per BBOE across all planning areas even though its total social costs are among the lowest (less than $0.5 million). The very high costs per BBOE result from dividing the estimated total net social costs for the Straits of Florida by the estimated leasable resources and then expressing the costs on a per BBOE basis (see Appendix G). The estimated social costs for the Straits of Florida are nearly all fixed costs (wetland loss due to pipeline installation), which would not increase proportionately if the resource estimate increased. Thus, the BBOE cost for the Straits of Florida would be lower if the resource estimate were higher.

/2 The BBOE net social cost estimates for the Cook Inlet, Hope Basin, Kodiak, and Shumagin planning areas were calculated using estimates of developable resources for the high price case (see Appendix G).

## II.B.3. Relative Marine Productivity and Environmental Sensitivity

Section 18(a)(2)(G) of the OCS Lands Act, as amended, requires that the Secretary of the Interior consider the relative marine productivity and environmental sensitivity of the various oil and gas bearing physiographic regions of the OCS in determining the timing and location of oil and gas activities. Analyses of relative marine productivity and environmental sensitivity were conducted to aid in the development of the 1982 OCS leasing schedule (Part II.B and Appendix 10 of the SID for the 1982 program). Those analyses demonstrated the complexity of collecting, analyzing, and interpreting scientific information to satisfy the requirements of section 18(a)(2)(G). In spite of the difficulties described in the 1982 analyses, the approaches to those analyses were upheld as reasonable by the U.S. Court of Appeals for the District of Columbia on July 5, 1983.

In preparation for current analyses, analytical approaches were discussed with the OCS Advisory Board Policy Committee (October 1984) and Scientific Committee (November 1984). The present analysis incorporates the advice and guidance received. Suggestions from these advisory groups were also considered during the preparation of the environmental impact statement (EIS) for the Proposed Final Program. Almost all parties who provided advice agreed that both the productivity and sensitivity analyses required by section 18(a)(2)(G) are complex and difficult. In addition, the Department has received or developed more information on the habitats and biota of the OCS than was available in 1982. The principal mechanism for the Department to develop such information is the OCS Environmental Studies Program administered by the Minerals Management Service.

Appendix I contains a more detailed explanation of the relative marine productivity and environmental sensitivity analyses summarized here. The information developed in the present analyses will be considered in and of itself as well as an input to the social costs analysis in Part II.B.2 and Appendix G of this SID. The assumptions used to determine the environmental sensitivity of a habitat or resource differ from those used in the analysis of social costs in the following ways:

1. The probability of the occurrence of an oil spill is an integral part of the calculation of social costs. This probability is a function of the estimate of oil and gas resources in the planning areas. The environmental sensitivity analysis is based upon the assumption that an oil spill has occurred and that the spilled oil has contacted habitats or biota of the planning area. The environmental sensitivity analysis does not rely upon resource estimates or consider the probability of the occurrence of an oil spill.

2. The calculation of social costs includes potential costs from air pollutant emissions and the loss of coastal wetlands. These impacts are not included in the environmental sensitivity analysis.

3. The analysis of social costs includes losses of commercial and/or subsistence fish resources. The environmental sensitivity analysis includes evaluations of the sensitivity of juvenile and adult fish and shellfish to crude oil. The social use of these resources is not considered in the environmental sensitivity analysis.

## Relative Marine Productivity

The term "productivity" has a distinct meaning to marine biologists. It means the "primary productivity" of marine plants. Primary productivity is the amount of plant tissue produced through photosynthetic fixation of carbon during a standard period of time. Both phytoplankton, microscopic marine plants, and fixed or rooted plants contribute to the primary productivity of most OCS planning areas. However, phytoplankton are the most important primary producers because of their large numbers and their wide distribution. Rooted or fixed plants are generally confined to the shallow portions of the planning areas. Phytoplankton can occupy all surface waters of a planning area and can fix carbon as long as sufficient light and nutrients are available. Riley (1970) estimated the normal range of marine primary productivity to be between 50 and 150 grams of carbon per square meter of ocean surface per year. Productivity in inshore areas and areas of upwelling can be as much as ten times greater than oceanic productivity.

The primary productivity of phytoplankton was used to rank the various planning areas in the 1982 analysis of relative marine productivity. Measurements of phytoplankton productivity have been made in almost all of the planning areas. The methods for measuring phytoplankton productivity are relatively standard. Most of the data used in the present analysis, except that provided by Smith and Kalber (1974), is based on carbon-14 assimilation measurements of phytoplankton productivity. Results of phytoplankton productivity studies are expressed in terms of the amount of carbon fixed during photosynthesis per unit area in a specified time. The figures used in the present analysis are expressed as grams of carbon fixed per square meter per year ($gC/m^2/yr$). By using a period of one year for reporting primary productivity, periods of extremely high or low productivity are incorporated in their appropriate importance in terms of their contribution to the annual productivity. This is especially important in areas where productivity is highly seasonal.

Phytoplankton productivity can vary more significantly within a planning area than between planning areas. For example, O'Reilley and Busch (1984) reported that productivity in the shallow areas of Georges Bank (North Atlantic) averaged 470 $gC/m^2/yr$ while in deeper waters landward of the shelf break, productivity averaged 370 $gC/m^2/yr$. Productivity in the deeper waters of the North Atlantic averaged 230 $gC/m^2/yr$. Determining an appropriate range or average productivity rate for the North Atlantic or any other planning area requires careful attention to the temporal and spatial significance of reported observations.

The 1982 analysis of marine productivity relied upon the "Estimation of organic production in the oceans" (Figure 1.1-5) presented by Smith and Kalber (1974). The productivity ranges provided in that undocumented map were used to rank the OCS planning areas. In the present analysis, the estimates of Smith and Kalber (1974) were compared with more current estimates based upon documented measurements (Table 9.1). In the 1982 analysis, the planning areas were grouped into four productivity classes: highest, next-to-highest, next-to-lowest, and lowest. The North Aleutian Basin and the St. George Basin were the only planning areas in the "highest" class. Based upon the data of Goering and McRoy (1981), the average annual productivity of these planning areas is substantially lower than the values reported by Smith and Kalber (1974). Only three productivity classes (high, moderate, and low) were distinguished in the present analysis (Table 9.2).

Twelve planning areas are included in the "high productivity" class. Further differentiation within this group must await more precise definition of the appropriate ranges or other statistical descriptions. The principal difference between the present analysis and the 1982 analysis is the elimination of the "highest" productivity class from the 1982 analysis and the inclusion of the North Aleutian Basin and the St. George Basin in the "high" productivity class of the present analysis.

In the present analysis, the planning areas designated as having "moderate" productivity are those with reported observations ranging from 50 to 200 $gC/m^2/yr$. Seven planning areas occur in this class. Although some high observations are reported for some of these areas, the overall annual productivity of these areas appears to be in the "moderate" range.

Finally, the three planning areas in the Arctic (Hope Basin, Chukchi Sea, and Beaufort Sea) are the least productive of the OCS planning areas. Information from Carey (1978) and Schell and Horner (1981) confirms the low productivity of these areas.

Additional Measures of Marine Productivity

The phytoplankton productivity data discussed in the present analysis is some of the most consistently expressed data in biological oceanography. Even so, comparisons among observed productivities are tenuous for the reasons described in the preceding discussion. Even with the additional data collected since 1982, available information is not sufficient to support a rigorous evaluation of the relative abundance of various organisms in the OCS planning areas. In many instances, quantitative information on some biota is unavailable, while for others, the development of "planning-area representative" information is not practical.

Nevertheless, information on the relative abundance of eight additional categories of biota was compiled, reviewed, and used in the matrix exemplified in Table 9.3 to complete the environmental sensitivity analysis. Available information on standing stocks and distributions was used to determine whether the "abundance" of the biota in a planning area relative to all other planning areas was high, moderate, or low. Making such determinations generally required extrapolations of existing data and simplifying assumptions. Some of these extrapolations and assumptions are described in the following sections.

TABLE 9.1

Marine Phytoplankton Productivity by Planning Area
Expressed as Grams of Carbon Fixed per Square Meter per Year

| Planning Area | Range of Values Used in the 1982 Analysis ($gC/m^2/yr$)* | More Recent Observations ($gC/m^2/yr$) | Reference |
|---|---|---|---|
| North Atlantic | 200-400 | 230-470 | O'Reilly & Busch (1984) |
| Mid-Atlantic | 200-400 | 260-370 | O'Reilly & Busch (1984) |
| South Atlantic | 50-200 | 130-360 | Haines & Dunstan (1975) |
| | | | Yoder et al. (1983) |
| Straits of Florida | 50-100 | | |
| Eastern Gulf of Mexico | 50-100 | 10-110 | UMES (1985) |
| Central Gulf of Mexico | 50-100 | 10-220 | El-Sayed & Turner (1977) |
| Western Gulf of Mexico | 50-100 | 15-70 | El-Sayed & Turner (1977) |
| Southern California | 200-400 | 180-360 | Eppley et al. (1979) |
| Central California | 200-400 | 10-470 | Riznyk (1977) |
| Northern California | 200-400 | 10-470 | Riznyk (1977) |
| Washington/Oregon | 200-400 | 35-350 | Small et al. (1972) |
| Gulf of Alaska | 200-400 | | |
| Cook Inlet | 200-400 | | |
| Kodiak | 200-400 | | Griffiths et al. (1982) |
| Shumagin | 200-400 | | |
| North Aleutian Basin | 400-7300 | 120-400 | Goering & McRoy (1981) |
| St. George Basin | 400-7300 | | |
| Navarin Basin | 50-200 | | |
| Norton Basin | 50-100 | | |
| Hope Basin | <50 | | |
| Chukchi Sea | <50 | 18-28 | Carey (1978) |
| Beaufort Sea | <50 | 10-20 | Schell & Horner (1981) |

* Data from Smith and Kalber(1974)

TABLE 9.2

Relative Phytoplankton Productivity of the OCS Planning Areas
Expressed as Grams of Carbon Fixed per Square Meter per Year

High Productivity (200 to 500 $gC/m^2/yr$)

North Atlantic
Mid-Atlantic
North Aleutian Basin
St. George Basin
Southern California
Central California
Northern California
Washington and Oregon
Gulf of Alaska
Cook Inlet
Kodiak
Shumagin

Moderate Productivity (50 to 200 $gC/m^2/yr$)

South Atlantic
Straits of Florida
Eastern Gulf of Mexico
Central Gulf of Mexico
Western Gulf of Mexico
Navarin Basin
Norton Basin

Low Productivity ($<50$ $gC/m^2/yr$)

Hope Basin
Chukchi Sea
Beaufort Sea

Relative Environmental Sensitivity

The concept of environmental sensitivity is even more complex than the concept of marine productivity. The 1982 analysis clearly demonstrated this complexity.

The 1982 analysis of environmental sensitivity was based, in large part, on an evaluation of the sensitivity of various coastal and marine habitats and biota to spilled crude oil. Limiting the analysis to spilled crude oil provided the following advantages:

1. Different areas of the OCS could be evaluated against a common factor, in this case, spilled crude oil.
2. Effects from overlapping factors could be avoided.
3. Oil spills, although rare, would cause the largest, most visible, and measurable effects of OCS activities.

The present analysis of environmental sensitivity also concentrates on the effects of spilled oil. However, some other factors are also evaluated in Appendix I-2 which is included in the Administrative Record. These factors include the following:

1. Operational discharges from OCS activities (drilling muds, cuttings, and formation waters).
2. Noise generated by OCS activities.
3. Habitat alteration from the installation of OCS facilities.
4. Air emissions from OCS operations.

These factors are not included in the calculations because of the difficulty of measuring their effects on the same basis as the effects of oil spills. In addition, information on the effects of these factors on habitats and biota throughout the entire OCS is not available. The effects of operational discharges, noise, habitat alteration, and air emissions are considered in environmental analyses prepared for the 5-Year Program and in subsequent sale-specific EIS's. While the cumulative effects of these four factors may be more extensive and long lasting than the effects of a large oil spill, the Department of the Interior and other Federal, State, and local agencies have means available to control some of the adverse effects of these factors.

For the present analysis, environmental sensitivity is defined in terms of the following variables:

1. the severity of damage resulting from the contact of spilled oil with various coastal and marine habitats and biota (this was designated as the persistence of oil in the 1982 analysis), and

2. the time required for the habitat or population to recover from the effects of contact with spilled oil.

The following assumptions are also included in the present environmental sensitivity analysis:

1. Spilled oil has not weathered significantly when it contacts the habitat or population. This assumption is conservative and provides an assessment of the most severe effects of spilled oil by eliminating the mitigating effects of weathering in the analysis. It also eliminates consideration of the distance between sensitive resources and potential oil fields or transportation routes and the mitigating effects of weathering on spilled oil moving from the site of production or transportation to the sensitive resource.

2. All of the biological populations in a planning area are contacted by spilled oil. Migratory species, which may inhabit the planning area for only a short period, are assumed to be present and contacted by spilled oil. Resources with seasonal sensitivities are assumed to be in their most sensitive stage when they are contacted by oil.

Performing an accurate analysis of environmental sensitivity requires a substantial amount of information on the spatial and temporal distribution of resources and the variations in their sensitivities to spilled oil. This is especially true where seasonal phenomena such as changes in productivity or the presence of migratory species would significantly increase or decrease the overall sensitivity of a planning area. If sufficient data were avialable, the overall environmental sensitivity of a planning area would be the sum of the sensitivities of its components integrated over time. This concept was reviewed during the preparation of the present analysis. It was abandoned because the minimum necessary information to conduct such an analysis is not available. Some information on some resources in some planning areas is available, but the data are neither consistent nor available for all planning areas. As a result, the present analysis contains the simplifying assumptions described above. If adequate information were available, it would be possible to develop both expected and worst-case sensitivities. The reliance of the present analysis on conservative assumptions is, nonetheless, appropriate for the purpose of comparing the relative environmental sensitivities of the OCS planning areas.

## Relative Marine Productivity/Environmental Sensitivity

In the present analysis, the distributions and environmental sensitivities of the three ecological components within and/or on the adjacent coast of each OCS planning area are evaluated. These three components are coastal habitats, marine habitats, and biota. Table 9.3 is an example of the calculations performed for each of these components. The calculations for each planning area are included in Appendix I-1.

The relative marine productivity and environmental sensitivity of the OCS planning areas are shown in Table 9.4. Alaskan OCS planning areas occupy the extremes of this table. The Navarin Basin has the lowest score because it has no coastal habitats. The planning areas with the highest scores are Hope Basin, North Aleutian Basin, St. George Basin, and Norton Basin. Since much of the information used in the calculation of relative marine productivity and environmental sensitivity is qualitative, each assigned value in the calculation has some degree of uncertainty. Thus, the scores provided in Table 9.4 should be viewed as estimates surrounded by some undefined variance. Scores with small differences between them should be viewed as relatively equal.

TABLE 9.3

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Hypothetical

Total Score: 290

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 200 | 33 | High | 225 | 74.25 |
| Sandy Beaches | 300 | 50 | Low | 45 | 22.50 |
| Rocky Beaches | 100 | 17 | Moderate | 135 | 22.95 |
| TOTAL | 600 | | | | 119.70 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 1,200,000 | 5.3 | Moderate | 135 | 7.16 |
| Submarine Canyons | None | 0.0 | Low | 45 | 0.00 |
| Coral Reefs | 5,000 | 0.02 | High | 225 | 0.05 |
| Hard Bottoms | 600,000 | 2.6 | Low | 45 | 1.17 |
| Shelf Break Zone | 850,000 | 3.7 | Low | 45 | 1.67 |
| Mud/Sand Bottom | 20,000,000 | 88.2 | Low | 45 | 39.69 |
| TOTAL | 22,655,000 | | | | 49.74 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | High | 5 | High | 5 | 25 |
| Adult Fish/Shellfish | Moderate | 3 | Moderate | 3 | 15 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Moderate | 3 | High | 5 | 15 |
| Marine Birds | High | 5 | High | 5 | 25 |
| Marine Turtles | None | 0 | Low | 1 | 0 |
| Marine Mammals | High | 5 | High | 5 | 25 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 120 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE 9.4

Relative Marine Productivity and Environmental Sensitivity of the OCS Planning Areas

| Planning Area | Overall Total Score |
|---|---|
| Hope Basin | 338 |
| North Aleutian Basin | 326 |
| St. George Basin | 287 |
| Norton Basin | 262 |
| Kodiak | 262 |
| Cook Inlet | 261 |
| Shumagin | 260 |
| Beaufort Sea | 257 |
| Washington-Oregon | 256 |
| Central Gulf of Mexico | 254 |
| Straits of Florida | 238 |
| Central California | 236 |
| Gulf of Alaska | 231 |
| South Atlantic | 230 |
| Northern California | 222 |
| Southern California | 219 |
| North Atlantic | 209 |
| Chukchi Sea | 200 |
| Eastern Gulf of Mexico | 198 |
| Mid-Atlantic | 198 |
| Western Gulf of Mexico | 180 |
| Navarin Basin | 141 |

The results of this analysis are generally consistent with available information on the relative sensitivity of coastal and marine resources to spilled oil. The results are also consistent with the current concepts of the relative sensitivity of coastal and marine habitats (COPRDM, 1981; NRC, 1985). This is most clearly shown for the Navarin Basin where coastal habitats are negligible. In addition, the presence of high populations of sensitive biota (coastal and marine birds, marine mammals, whales, juvenile fish and shellfish) are the major factors supporting the high total scores of the Alaskan planning areas. The ecological component which has the least effect on the total scores is marine habitats. This results from the assumption that spilled oil cannot be transported in significant amounts from the surface of the ocean to most benthic communities. The most sensitive marine habitats that could be affected are submerged vegetation and coral reefs, but these habitats do not occupy a significant portion of any planning area.

Several commentors on the Draft Proposed Program criticized the analysis of relative marine productivity and environmental sensitivity because of their dissatisfaction with the results. In particular, the scores for marine habitats were criticized because the sensitivities of marine habitats in many diverse planning areas were given equal scores due to lack of data. However, this lack of data on areal extent and sensitivity of marine habitats is not considered critical because most marine habitats are judged to have relatively low sensitivity to spilled oil (Appendix I-2) and therefore, are scored equally.

The method used to generate Total Scores was modified to assess the significance of having equal scores for marine habitats in diverse planning areas. The ranking of planning areas as to their relative marine productivity and environmental sensitivity was determined both as a composite of the individual scores for coastal habitats, marine habitats, and biota (Table 9.4) and for coastal habitats and biota without marine habitats (Table 9.5). The final order of planning areas is practically identical whether marine habitats are considered or not. As stated previously, scores with small differences between them should be viewed as relatively equal. Thus, the model is not sensitive to the lack of data on areal extent of low sensitivity marine habitats.

The results of this analysis should not be construed as indicating the level of impacts expected as a result of OCS development. In this analysis, sensitivity is determined from the likely response of the resource to the environmental perturbation without consideration of risk, likelihood of adverse impact, or vulnerability. Thus, the sensitivity ratings represent a conservative analysis. Additional factors would need to be considered to determine the expected level of impacts in a planning area from OCS oil and gas operations. These factors include the projected amount of hydrocarbon resources, their probable location within the planning area, the number and trajectory of hypothetical oil spills, and the location of possible spill sites, among others.

A high total score or the presence of many sensitive resources in a planning area does not necessarily imply a high level of adverse effects from OCS development. Even those areas ranked with relatively low scores possess sensitive resources which will require consideration of specific environmental impacts at the sale stage and evaluation to determine the need for special protective measures.

TABLE 9.5

Relative Marine Productivity and Environmental Sensitivity of the OCS Planning Areas Calculated as the Sum of the Scores for Coastal Habitats and Biota

| Planning Area | Score |
|---|---|
| Hope Basin | 293 |
| North Aleutian Basin | 281 |
| St. George Basin | 242 |
| Norton Basin | 217 |
| Kodiak | 217 |
| Cook Inlet | 216 |
| Shumagin | 215 |
| Beaufort Sea | 212 |
| Washington-Oregon | 211 |
| Central Gulf of Mexico | 209 |
| Central California | 190 |
| Gulf of Alaska | 186 |
| South Atlantic | 184 |
| Straits of Florida | 183 |
| Northern California | 177 |
| Southern California | 173 |
| North Atlantic | 164 |
| Chukchi Sea | 155 |
| Mid-Atlantic | 153 |
| Eastern Gulf of Mexico | 147 |
| Western Gulf of Mexico | 135 |
| Navarin Basin | 96 |

Effects of Subarea Deferrals

Relative marine productivity and environmental sensitivity rankings of the OCS planning areas have been recalculated for the Proposed Final Program based on the Secretary's proposals in the Proposed Program to defer some subareas and to highlight others for further analysis. Appendix I-3 includes calculations for each candidate deferral area and cumulatively for all deferral candidates by planning area. The scores in Table 9.6 are the cumulative scores for the reconfigured planning areas after candidate deferral areas identified by the Secretary or proposed by others have been removed. The number of potential individual subarea deferrals makes it impractical to produce tables for all possible deferral combinations within each planning area.

For several reasons, the calculation of social costs (Appendix G) is based on the relative rankings of the entire planning areas provided in the Proposed Program, rather than from a ranking of planning areas with subareas deferred. First, deferral of a subarea may actually reduce the level of relative risk to living resources, but deferral does not eliminate the risk because other portions of the planning area or adjacent planning areas may be leased for oil and gas development. Thus, with the assumption that an oil spill will occur and that the spilled oil will contact all resources, the score for the entire planning area remains the most consistent basis for ranking relative environmental sensitivity.

Second, the ranking of the areas remaining after subareas are deferred involves an assessment of the relative risk that oil spills will contact the living resources of the subareas. The results of that ranking are inconsistent with those used in the original ranking which were based on the assumption that all living resources within a planning area would be contacted by an oil spill. The assumption used in the original ranking is more appropriate for purposes of measuring relative environmental sensitivity.

Third, the Secretary has already announced his proposal to defer some subareas but the question of which, if any, additional subareas may be deferred will not be resolved until the Secretary decides on the Final Program. Hence, given the large number of possible combinations of subareas, ranking of planning areas with subareas omitted cannot be applied to the calculation of social costs prior to his decision. In view of these analytical considerations, it was decided that the appropriate scores for use in Appendix G should continue to be the scores for the entire planning areas.

Nevertheless, the results provided in Table 9.6 and Appendix I-3 are available for the Secretary's consideration as a sensitivity test in considering the effect of subarea deferrals on the relative marine productivity and environmental sensitivity of the OCS planning areas. Each of the three ecological components used to compute relative environmental sensitivity (coastal habitats, marine habitats, and biota) has a different effect on the total score for the planning area. Subarea deferrals which remove extensive areas of sensitive coastal habitats from probable contact by oil spilled on the OCS generally produce the most significant

Table 9.6

Relative Marine Productivity and Environmental Sensitivity
of OCS Planning Areas Following the Cumulative Deferral of Subareas

| Planning Area | Score |
|---|---|
| Hope Basin | 338 |
| North Aleutian Basin | 326 |
| Kodiak | 262 |
| Cook Inlet | 261 |
| Shumagin | 260 |
| Beaufort Sea | 257 |
| Central Gulf of Mexico | 254 |
| Straits of Florida | 246 |
| Gulf of Alaska | 231 |
| Washington/Oregon | 216 |
| Chukchi Sea | 200 |
| Western Gulf of Mexico | 180 |
| Southern California | 178 |
| St. George Basin | 143 |
| Navarin Basin | 141 |
| Eastern Gulf of Mexico | 137 |
| Norton Basin | 137 |
| South Atlantic | 124 |
| Mid-Atlantic | 118 |
| North Atlantic | 98 |
| Central California | 80 |
| Northern California | 80 |

reductions in overall relative environmental sensitivity. In contrast, marine habitat subarea deferrals generally result in a relatively small effect on the total score. Subarea deferrals have widely varying effects on the scores for biota. The effects range from relatively significant to nearly none depending on the area deferred and the sensitivities and distributions of the different groups or types of species. Subarea deferrals have no significant effect on the ranking of planning areas for relative marine productivity. Marine productivity is an expression of primary productivity in grams of carbon per unit area. The size of the area, therefore, does not affect the expression of productivity. Moreover, the data from which primary productivity has been computed include samples from stations which vary in location and time such that results would be compromised if subsets of samples were used as relative measures of productivity. This variation is especially critical because samples taken at different times may yield a greater range in results than samples taken from different locations and only locational differences are relevant for purposes of subarea analysis.

## II.C. <u>Equitable Sharing of Developmental Benefits and Environmental Risks</u>

Section 18(a)(2)(B) requires that the Secretary base the timing and location of OCS exploration, development, and production on a consideration of, among other things, an

> ". . . equitable sharing of developmental benefits and environmental risks among the various regions."

Compliance with this requirement involves four key elements which will be addressed in this section: 1) the identification and presentation of developmental benefits and environmental risks; 2) the description of their actual sharing among the various regions; 3) the discussion of the concept of equitable sharing; and 4) the discussion of how the "consideration of . . . an equitable sharing. . ." is to be reflected in the scheduling of OCS lease sales.

In <u>California v. Watt (II)</u> (at 594-95), the court upheld the sufficiency of the analysis under section 18(a)(2)(B) which was presented in the SID for the 1982 leasing program. The analysis presented here uses the same approach, but is somewhat expanded.

### <u>Distribution of Benefits and Costs to Regions</u>

The developmental benefits analyzed in this section are the economic benefits of production as described in Part II.B.1 and Appendix F. The environmental risks discussed in this section are the social costs which are analyzed in Part II.B.2 and Appendix G.

Estimates of both economic benefits and social costs have been calculated on a planning area basis. Tables 3 and 7 show how the estimated economic benefits and social costs are distributed among the planning areas. While we can attribute certain benefits and costs to activity in a particular planning area of the OCS, how these benefits and costs are shared by the population onshore is not as obvious.

The court upheld the Secretary's consideration of the equitable sharing of the developmental benefits and environmental risks among the people of seven regions comprised of one or more coastal States in addition to the sharing among OCS planning areas. For this analysis, basically the same seven regional units are also used, as follows:

- Region I - Maine, New Hampshire, Massachusetts, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Delaware, Maryland, Virginia
- Region II - North Carolina, South Carolina, Georgia
- Region III - Florida
- Region IV - Texas, Louisiana, Mississippi, Alabama
- Region V - California
- Region VI - Washington, Oregon
- Region VII - Alaska

The alternative of limiting regions to individual coastal States in all cases would make the analysis less informative. Because there is more uncertainty in estimating the environmental risks borne by individual States as opposed to those borne by the regional grouping in Regions I, II, IV, and VI, the regional approach has been retained in those cases. Where that limitation does not apply, however, single States have been treated as regions--as in the 1982 analysis (e.g., Regions III, V, and VII). It should be noted that Regions V and VI share some of the environmental risks arising from production offshore Alaska (see Appendix G). It should also be noted that Pennsylvania has been added to Region I. While Pennsylvania has no coastline directly adjacent to the OCS, Pennsylvania is defined as an "affected State" under 43 USC 1331 and 30 CFR 256.14.

Equitable Sharing and the Scheduling of OCS Lease Sales

Further discussion of equitable sharing occurred in the court's review of whether the 1982 leasing program was based on the factors listed in section 18(a)(2). It should be noted that the court did not set a specific standard of equitable sharing of developmental benefits and environmental risks which the Secretary was to achieve. Rather, the court sanctioned the Secretary's choice of a program in 1982 which scheduled sales based on a consideration of equitable sharing of environmental risks among OCS regions pursuant to section 18.

In its opinion, the court held that in some circumstances it was appropriate to determine the location of sales in various planning areas on a basis other than relative net social value. Net social value is the measure of the overall value of oil and gas production to the Nation calculated by subtracting the social costs of such production (analyzed in Part II.B.2 and Appendix G) from its net economic value (analyzed in Part II.B.1 and Appendix F).

In particular, the court found that it was appropriate to schedule sales so as to expedite exploration in frontier areas (California v. Watt (II) at 599). Thus, leasing need not be scheduled in a manner that strictly reflects the projections of high value and potential for discovery in higher net social value areas in contrast to frontier areas. One basis for such an approach is the recognition that net social value estimates are only approximate indicators of what will result from OCS leasing. As was discussed in Part I, many effects are not quantifiable and thus cannot be included in the net social value calculation. In addition, actual hydrocarbon deposits may well prove to be distributed quite differently than as predicted by today's best estimates. Indeed, the court also recognized in a different but still relevant context that ". . . the Secretary realized that the cost-benefit analysis [i.e., the calculation of the net social value of planning areas and alternative schedules] should be used only for generalized conclusions. He did not think that the analysis would provide an adequate basis for making distinctions between planning areas" (California v. Watt (II) at 605).

In light of the court's opinion, the factors which need to be considered in making a determination about the equitable sharing of developmental benefits and environmental risks include numerous significant factors not under the control of the MMS to wit: the natural distribution of oil and gas resources among the areas of the OCS; the history of development of technology for oil and gas exploration, development, and production; the history of industry exploration and production strategies in State waters as well as the OCS; and the congressional and injunctive constraints which have been imposed on OCS leasing. The MMS's estimates of the natural distribution of economically recoverable oil and gas can be found in Appendix E. A brief summary of the history of leasing offshore can be found in Appendix F.

The court sanctioned the scheduling of more sales in frontier areas than would result from relative net social value alone. This fact has to be interpreted in light of the overall purposes of the OCS Lands Act Amendments (OCSLAA), the first of which is "to achieve national economic and energy policy goals, assure national security, reduce dependence on foreign sources, and maintain a favorable balance of payments in world trade" (OCSLAA section 102(1)). In this context, the court explicitly upheld "...the Secretary's interpretation of the congressional intent to expedite offshore lease sales, particularly in frontier areas" (California v. Watt (II) at 599), (emphasis in the original). The Secretary is required to consider equitable sharing in addition to all the other factors and objectives he must consider.

Thus, the court upheld the grouping of OCS planning areas by their relative net social value as the general basis for scheduling OCS lease sales. The court also provided, however, for the modification of the net social value basis of scheduling sales with respect to frontier areas so that the regional contribution to the achievement of the overall purposes of the OCSLAA could be made more equitable. The full discussion of the scheduling of sales in Part III of this SID reflects the court's interpretation cited just above.

Comments concerning equitable sharing were received on the Proposed Program from State Governors, State Agencies, local governments, industry, and public interest groups. A few commenters, especially the Governor of Louisiana and the Louisiana Association of Business and Industry, stated that the Proposed Program does not treat areas with high resource potential and high industry interest equally and that the Proposed Program fosters dependence on the Gulf of Mexico's reserves while deferring exploration in other planning areas. On the other hand, the California legislature and California's Lieutenant Governor asserted that California produces a large amount of OCS oil and gas and therefore should have certain areas placed off limits to leasing. Local governments and interest groups in California expressed concern over the uneven burden of environmental risk that the region would bear under the Proposed Program. The comments received on both sides of the issue were to the effect that the overall objective of equitable sharing of developmental benefits and environmental risks would not be met.

In evaluating these comments, it should be kept in mind that equitable sharing should be viewed from a national perspective, taking into account the benefits that would occur as well as the risks to individual areas. Further, in balancing objectives the statute requires as one consideration focusing on acreage with the highest economic value and industry interest among the planning areas. But this is not without full regard for environmental risks and the need to explore frontier areas.

Developmental Benefits and their Distribution

Developmental benefits are largely captured for subsequent distribution in the form of Federal revenues and to a lesser extent in the form of corporate profits. Within each region, some individuals and firms whose labor, land, materials, equipment, or other factors of production are used in OCS development regard the purchase of those resources as a benefit. In this respect, OCS production can result in development of the kind that States and localities often seek under a variety of local, State, and Federal development programs. From the viewpoint of the Nation, however, the costs of these inputs are subtracted from production revenues in estimating net economic value.

In the context of equitable sharing of benefits among regions, it is worth noting that the States and localities can use tax policies and user fees to capture some of these developmental benefits to pay for the additional public services which may be required by any additional population attributable to OCS development. In fact, it was in this context, with particular regard to perceived infrastructure costs burdening local governments as a result of OCS activities off their jurisdictions that numerous comments were received from local governments and public interest groups. This issue is treated in Appendix G and in Part II of the SID, where infrastructure costs are included in social costs. However, while these costs may be real, they do not come without benefits. Indeed, the demands for additional public services as a result of OCS activity comes from increased economic activity and employment that increase the output and income of the locality and are subject to the taxing decisions of the State and the affected localities. While it is recognized that the incidence of costs and benefits may not be perfectly matched, the same may be said of the impact of other major economic or institutional changes, such as the opening of a new automobile plant. The net effect, regionally and nationally, is that economic benefits usually exceed social costs. In Alaska, however, benefits may be lower than in other regions because fewer OCS workers may take up residence in local communities.

The sharing of benefits among the populations of coastal States varies depending upon the form of the benefit. For example, approximately $1.5 billion in revenues was recently distributed, as specified by the OCS Lands Act Amendments of 1985, to seven coastal States having Federal oil and gas leases adjacent to State waters. These monies consisted of $1.4 billion of funds deposited in a special account plus 27 percent of royalties and accrued interest. Revenues were distributed in the following amounts: Louisiana, $616 million; Texas, $425 million; California, $338 million; Alabama, $66 million; Alaska, $51 million; Mississippi, $14 million; and Florida, $.03 million. Further, in California, coastal communities receive a portion of the State's share of Federal offshore revenues. These funds are specifically earmarked to help local governments offset the environmental and economic costs imposed by growth in offshore oil and gas development.

The distribution of revenues provided by the OCS Lands Act Amendments of 1985 resolved a long-standing dispute between the States and Federal government regarding receipts held in special accounts established pursuant to section 8(g) of the OCSLA. In addition to the accumulated receipts from past leases, the April 1986 amendments to the OCSLA require that 27 percent of bonuses, rents, and royalties, derived from Federal leases which lie within 3 nautical miles of the seaward boundary of any coastal State is transmitted on a monthly basis to the State along with any interest accrued thereon. The Congress noted that the payment authorized by the 1986 amendments would "... provide affected coastal States and localities with funds which may be used for the mitigation of adverse economic and environmental effects related to the development of [oil and gas] resources."

Most developmental benefits, however, are captured for subsequent distribution in the form of Federal revenues from lessees' cash bonus payments, rentals, royalties, income taxes, and other sources. There are a variety of ways to view how the benefits derived from increased Federal revenues would be shared. From one perspective, they would be distributed in about the same way Federal tax payments are collected because without OCS revenues the Federal Government would have to collect equivalent receipts through more taxes to sustain a given level of Federal expenditures. From another perspective, the distribution would be proportional to population because Federal programs benefit the public in general. A third perspective would distribute the benefits in proportion to Federal funds provided to State and local governments. All three ways of sharing benefits could be considered to be equitable because the revenues from the OCS are appropriated by law on behalf of the public as a whole.

Benefits that arise in the form of corporate profits are distributed to people directly or indirectly in the form of stock dividends or the value of company stock. This distribution tends to be quite wide nationally speaking--it is certainly not likely to be concentrated in coastal areas. Thus, the distribution of company benefits is not unlike the distribution of Federal benefits. On the other hand, many of the perceived benefits from the purchase of factors of production used in OCS development tend to fall within the coastal areas providing the labor and materials used offshore. However, neither of these forms of benefit is likely to be large in comparison to the increases in Federal revenues. For these reasons, consideration of an equitable sharing of developmental benefits in this section is based primarily on the distribution to the various regions of benefits that are captured in the form of Federal revenues.

Table 10 shows how the total net economic value of the OCS oil and gas resources would be distributed under each of the three perspectives suggested above. Table 10.1 shows the distribution of total net economic value reflecting subarea deferrals. There are relatively few differences among the three. The one exception is that Alaska's share of Federal grants to State and local governments is two to three times greater than its share of tax payments and population.

## Environmental Risks and their Distribution

As stated earlier in this section, environmental risks are based on the analysis of social costs in Appendix G. While net social costs measure the estimated non-development costs of producing an area's leasable resources to the Nation as a whole, they do not indicate the distribution of costs and in particular what the costs are to residents of each onshore area adjacent to the planning area.

The distribution of costs among the population tends to be skewed toward residents of coastal States. These people are more likely to be adversely affected by OCS development than inland residents.

To assess the costs borne by residents of coastal States adjacent to OCS areas resulting from the production of the leasable resources unleased as of Mid-1987, estimates were developed of regional cost. Regional cost as defined in Appendix G is a measure of the costs borne by the users of and onshore residents adjacent to an OCS planning area from OCS production in that area. The regional costs in Table 11 have been estimated by subtracting from the gross social cost associated with OCS production in an area, the compensation payments paid to residents for oil spill damages (assumed to be 50 percent of oil spill losses), and for commercial gear conflict losses (assumed to be 60 percent of all losses). Also

Table 10. Three Approaches to the Estimated Regional Distribution of Approximately $19.1 to $83.4 Billion Variation of Net Economic Value (N.E.V.) Resulting from Total Production of Leasable Resources as of Mid-1987 /1 (Dollar amounts in billions)

| Regions /2 | Region's Share of Total Federal Tax Payments/3 | Resulting Share of N.E.V. Low - High | Regions's Share of Total U.S. Population/4 | Resulting Share of N.E.V. Low - High | Region's Share of Total Federal Grants/5 | Resulting Share of N.E.V. Low - High |
|---|---|---|---|---|---|---|
| I | 28.2 | $5.4 - 23.5 | 25.3 | $4.8 - 21.1 | 27.3 | $5.2 - 22.8 |
| II | 5.4 | 1.0 - 4.5 | 6.5 | 1.2 - 5.4 | 5.5 | 1.1 - 4.6 |
| III | 4.7 | 0.9 - 3.9 | 4.6 | 0.9 - 3.8 | 3.0 | 0.6 - 2.5 |
| IV | 10.7 | 2.0 - 8.9 | 11.4 | 2.2 - 9.5 | 8.7 | 1.7 - 7.3 |
| V | 12.2 | 2.3 - 10.2 | 10.8 | 2.1 - 9.0 | 10.0 | 1.9 - 8.3 |
| VI | 2.9 | 0.6 - 2.4 | 3.0 | 0.6 - 2.5 | 3.1 | 0.6 - 2.6 |
| VII | 0.3 | 0.1 - 0.3 | 0.2 | * - 0.2 | 0.6 | 0.1 - 0.5 |

/1 Net economic value was calculated on planning area basis (see Part II.B and Appendix F). Net economic value was allocated to the adjacent coastal regions in proportion to each region's share of the national total in three specific categories: the region's share of total Federal tax payments; the region's share of population; and in proportion to total Federal intergovernmental grants. The estimated regional share of total net economic value for this table was calculated by multiplying the total net economic value for all planning areas by each region's proportional share (expressed as a percentage) of each of the three variables in the table. The variation of total net economic value equals about $19.1 to $83.4 billion. Thus, Region I's share of the total N.E.V., if the distribution were based on its share of total Federal tax payments, would be 28.2 percent, or $5.4 to $23.5 billion. Regional percentages total less than 100 because only coastal States are included in the calculation. The remainder of the net economic value not accruing to the coastal Regions may be apportioned to the non-coastal States.

/2 Regions are--I. Maine, New Hampshire, Massachusetts, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Delaware, Maryland, Virginia; II. North Carolina, South Carolina, Georgia; III. Florida; IV. Texas, Louisiana, Mississippi, Alabama; V. California; VI. Washington, Oregon; and VII. Alaska.

/3 Source: Tax Foundation; Tax Features Vol. 30, No. 4; April, 1986.

/4 Source: U.S. Bureau of the Census, Current Population Reports, Series P-26, No. 84, 1984 Population and 1983 Per Capita Income Estimates for Counties and Incorporated Places, U.S. Government Printing Office, Washington, D.C., 1986.

/5 Source: U.S. Department of Commerce; Bureau of the Census; Federal Expenditures By State for Fiscal Year 1986; March 1986.

* Negligible (estimated to be less than 0.5 million $1987)

Table 10.1 Three Approaches to the Estimated Regional Distribution of Approximately $18.2 to $78.2 Billion Variation of Net Economic Value (N.E.V.) Resulting from Total Production of Leasable Resources as of Mid-1987 Reflecting Cumulative Subarea Deferrals /1 (Dollar amounts in billions)

| Regions /2 | Region's Share of Total Federal Tax Payments/3 | Resulting Share of N.E.V. Low - High | Regions's Share of Total U.S. Population/4 | Resulting Share of N.E.V. Low - High | Region's Share of Total Federal Grants/5 | Resulting Share of N.E.V. Low - High |
|---|---|---|---|---|---|---|
| I | 28.2 | $5.1 - 22.1 | 25.3 | $4.6 - 19.8 | 27.3 | $5.0 - 21.3 |
| II | 5.4 | 1.0 - 4.2 | 6.5 | 1.2 - 5.1 | 5.5 | 1.0 - 4.3 |
| III | 4.7 | 0.9 - 3.7 | 4.6 | 0.8 - 3.6 | 3.0 | 0.5 - 2.3 |
| IV | 10.7 | 1.9 - 8.4 | 11.4 | 2.1 - 8.9 | 8.7 | 1.6 - 6.8 |
| V/6 | 12.2 | 2.2 - 9.5 | 10.8 | 2.0 - 8.4 | 10.0 | 1.8 - 7.8 |
| VI | 2.9 | 0.5 - 2.3 | 3.0 | 0.5 - 2.3 | 3.1 | 0.6 - 2.4 |
| VII | 0.3 | 0.1 - 0.2 | 0.2 | * - 0.2 | 0.6 | 0.1 - 0.5 |

/1 Net economic value was calculated on planning area basis (see Part II.B and Appendix F). Net economic value was allocated to the adjacent coastal regions in proportion to each region's share of the national total in three specific categories: the region's share of total Federal tax payments; the region's share of population; and in proportion to total Federal intergovernmental grants. The estimated regional share of total net economic value for this table was calculated by multiplying the total net economic value for all planning areas by each region's proportional share (expressed as a percentage) of each of the three variables in the table. The variation of total net economic value equals about $18.2 to $78.2 billion. Thus, Region I's share of the total N.E.V., if the distribution were based on its share of total Federal tax payments, would be 28.2 percent, or $5.1 to $22.1 billion. Regional percentages total less than 100 because only coastal States are included in the calculation. The remainder of the net economic value not accruing to the coastal Regions may be apportioned to the non-coastal States.

/2 Regions are--I. Maine, New Hampshire, Massachusetts, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Delaware, Maryland, Virginia; II. North Carolina, South Carolina, Georgia; III. Florida; IV. Texas, Louisiana, Mississippi, Alabama; V. California; VI. Washington, Oregon; and VII. Alaska.

/3 Source: Tax Foundation; Tax Features Vol. 30, No. 4; April, 1986.

/4 Source: U.S. Bureau of the Census, Current Population Reports, Series P-26, No. 84, 1984 Population and 1983 Per Capita Income Estimates for Counties and Incorporated Places, U.S. Government Printing Office, Washington, D.C., 1986.

/5 Source: U.S. Department of Commerce; Bureau of the Census; Federal Expenditures By State for Fiscal Year 1986; March 1986.

/6 Share of net economic value for California was calculated for the Panetta Proposal.

* Negligible (estimated to be less than 0.5 million $1987)

deducted from the gross social cost associated with OCS production in an area are the costs avoided because OCS oil production in an area reduces oil imports into that area, and hence imported oil-related spills.

The production of OCS oil, though it may result in oil spills, also reduces the amount of oil imported and thus reduces the spills that would occur from tankers carrying imports in U.S. coastal waters. While the social cost analysis does not assume the backing out of imported oil by domestic natural gas production, it should be noted that OCS exploration and development more often leads to the production of natural gas resources rather than oil. In FY 1985 about 25 percent of domestic production of natural gas was from the OCS and, on a barrel of oil equivalent basis, natural gas accounted for approximately two-thirds of the hydrocarbons produced on the OCS. The discovery of natural gas resources can increase the beneficial economic and environmental effects of backing out imported oil or can result in additional benefits for two reasons: (1) OCS gas production can displace some imported oil thereby reducing imported oil-related spills; and (2) the greater availability of more OCS natural gas may lead to fuel switching from oil to natural gas, which is a cleaner-burning fuel. This effect can in turn be enhanced by the fact that the rollover of capital stock which often occurs during fuel switching results in a general upgrading of the level of efficiency with which fuel is used.

It should be pointed out that Table 11 indicates that the Gulf of Mexico Region is estimated to incur higher costs in this analysis than was estimated to be the case in the 1982 analysis. However, Table 10 indicates that the benefits which accrue to the Gulf of Mexico Region far outweigh those costs--as is the case for all Regions. In addition, as discussed above in this section, consideration of the scheduling of OCS lease sales in frontier areas further addresses the requirements of section 18(a)(2)(B) with respect to the consideration of equitable sharing of costs vis-a-vis mature production areas such as the Gulf of Mexico. Finally, in the context of the benefits to the Nation as a whole, Tables 1, 2, and 3 make clear the loss to the Nation which could result from unduly restricting oil and gas leasing in the Gulf of Mexico.

In conclusion, the developmental benefits of OCS leasing are shared widely while the environmental risks are concentrated in regions adjacent to the areas of the OCS in which most of the unleased oil and gas resources are expected to be leased and produced. The uneven burden of environmental risk should be reduced substantially by compensation that will be provided to those suffering damages from oil spills and commercial fishing gear losses. Further reductions in the unevenness of environmental risk could be achieved by increasing compensation, by imposing stricter controls or stipulations, or by restricting leasing in areas of higher environmental risk. As noted above, however, the court found that restricting leasing in frontier areas can lead to an inequitable sharing of environmental risks (California v. Watt (II) at 599). In addition, restrictions would need to be substantial in order to change markedly the distribution of environmental risk. Such restricted leasing would, however, substantially reduce benefits to the Nation as a whole.

Table 11. Distribution of Range of Social Costs by Region from Production of All Estimated Leasable Resources Unleased as of Mid-1987 (Millions of 1987 Dollars)

| Regions | Regional Costs/a Low | Regional Costs/a High | Regional Costs Reflecting Cumulative Subarea Deferrals/a Low | Regional Costs Reflecting Cumulative Subarea Deferrals/a High |
|---|---|---|---|---|
| I. Maine, New Hampshire Massachusetts, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Delaware, Maryland, Virginia | .5 | .4/c | .5 | .3/c |
| II. North Carolina, South Carolina, Georgia | .9 | 2.0 | .8 | 1.7 |
| III. Florida | 4.0 | 8.9 | 3.9 | 8.5 |
| IV. Texas, Louisiana, Mississippi, Alabama | 59.0 | 49.6/c | 59.0 | 49.6/c |
| V. California | 14.2 | 28.6 | 7.1/d | 16.2/d |
| VI. Washington, Oregon | .5 | 1.2 | .5 | 1.2 |
| VII. Alaska /b | * | 25.8 | * | 25.2 |

/a The regional cost is estimated on a planning area basis as the gross social cost estimated to result from the production of that area's resources minus compensation pursuant to provisions of the OCS Lands Act Amendments of 1978 for potentially resultant oil spill and commercial fishing gear conflict losses, and minus the social cost avoided when oil production in the area backs out oil imports to the area (see Appendix G). Regional costs are calculated to include the costs associated with transshipment of oil produced in other OCS areas to or through that one OCS area. These planning area figures are allocated as follows: where a Region's coastline corresponds to one or more planning areas, for example, California, the total costs from the adjacent planning areas are allocated to the Region by adding them together; where adjacent planning areas do not coincide with State offshore boundary extensions, costs are allocated to Regions in proportion to their State coastline mileages.

/b The wide variability in regional costs for Alaska occurs because none of the planning areas has leasable resources at the $14 per barrel starting price. See Table 8 in Appendix F.

/c Regions I and IV incur higher regional social costs under the low oil price scenario versus the high oil price scenario. Net regional costs are higher for the North and Mid-Atlantic and the Central and Western Gulf of Mexico planning areas at the $14 starting oil price compared to net regional costs for these areas at $29. Regional costs for the Mid-Atlantic planning area are negative at the $29 starting oil price. Negative net regional costs occur when oil spill and non-oil-spill costs are more than offset by compensation payments and by reduced oil spill damages from foreign tankers when imports are replaced by OCS oil and gas production. Higher net regional costs in the Central and Western Gulf of Mexico at $14 starting oil price occurs because the amount of natural gas leasable in the Western Gulf of Mexico, and in general the amount of resources available in all areas, drops as the initial oil price is decreased from $29 to $14. As a result, more oil is imported and spillage from foreign tankers is greater.

/d Regional costs based on the Panetta Proposal

* Negligible (estimated to be less than 0.5 million of $1987)

## II.D. Balancing Considerations

Section 18(a)(3) requires that:

> "The Secretary shall select the timing and location of leasing, to the maximum extent practicable, so as to obtain a proper balance between the potential for environmental damage, the potential for the discovery of oil and gas, and the potential for adverse impact on the coastal zone."

In California v. Watt (II) (at 606), the court upheld the cost-benefit analysis used in the formulation of the July 1982 5-Year OCS Oil and Gas Leasing Program as a means of compliance with section 18. In that 1982 analysis, as in the current analysis, the general interpretation of this requirement is that there is a presumption that an area should be included on the schedule if the expected benefits of oil and gas activities there exceed the expected costs, and that the most valuable areas should be offered first and most frequently. Estimates of the benefits from discovery and production of oil and gas and of the social costs, including a consideration of the factors listed in section 18(a)(2), have been calculated as discussed in Part II.B and Appendices F and G. These estimates have been used to calculate estimates of the net social value by planning area.

Net social value is the difference between the net economic value and the social cost estimated for total production of an area's unleased leasable resources, assuming that all are leased as of mid-1987 and developed in the normal timeframe thereafter. Table 12.1 displays the variation of estimated net social value by planning areas for the assumed range of starting oil prices. Table 12.2 balances benefits and costs on a per barrel basis for low value areas for which the method used for Table 12.1 was not applicable.

The presumption that areas with positive net social value estimates are to be included on the schedule is subject to modification based on the qualitative information not included in the net social value calculations. Such qualitative information appears in Part II.A, Part II.B.3, and Appendices B, C, H, I, and J. Further qualitative information is contained in the EIS.

Careful examination of section 18(a)(3) and the methods used in the calculation of net social value indicates that the three considerations to be balanced ("the potential for environmental damage, the potential for the discovery of oil and gas, and the potential for adverse impact on the coastal zone") are not mutually exclusive. For example, there is an overlap between the potential for adverse impact on the coastal zone and the potential for environmental damage. Also, increased domestic production of OCS oil and gas can cause environmental damage and adverse impacts on the coastal zone--but can also reduce tankered imports of oil and thus reduce the potential for environmental damage and adverse impact on the coastal zone. The discovery of OCS natural gas in particular has the added potential for environmental and economic efficiency improvements, as discussed above with respect to equitable sharing. Furthermore, the beneficial effects which rigs can have as fishing reefs in some areas also shows that there can be gains which can offset to some extent the potential social costs of production.

It is worth reiterating that the section 18 analyses have been conducted such that the net economic benefits of leasing tend to be understated and the social costs of leasing tend to be overstated. In addition, it is noteworthy that even if all social cost figures were 59 times greater, the net social value of leasing and production would remain positive for all the areas where it is not negligible.

Table 12.1

Range of Estimated Net Social Value of Total Production of Unleased, Undiscovered OCS Oil and Gas Leasable Resources as of Mid-1987 by Planning Area Showing Variation by Starting Oil Price Cases /1

| Planning Area | Column 1 Variation of Estimated Net Economic Value of Leasable Resources ($ 1987 Millions) | | Column 2 Variation of Estimated Social Cost of Producing Leasable Resources ($ 1987 Millions) | | Column 3 Variation of Estimated Net Social Value ($ 1987 Millions) | |
|---|---|---|---|---|---|---|
| | (1A) Low Price Case | (1B) High Price Case | (2A) Low Price Case | (2B) High Price Case | (1A-2A) Low Price Case | (1B-2B) High Price Case |
| Central Gulf of Mexico (E)/2 | 9,432 | $31,236 | 42 | 42 | 9,390 | 31,194 |
| Western Gulf of Mexico (E) | 7,201 | 31,484 | 30 | 36 | 7,173 | 31,448 |
| Southern California (F-E) | 988 | 5,002 | 6 | 12 | 982 | 4,990 |
| South Atlantic (P-F) | 400 | 3,157 | 2 | 5 | 398 | 3,152 |
| Northern California (P-G) | 468 | 2,706 | 4 | 6 | 464 | 2,700 |
| Eastern Gulf of Mexico (G) | 180 | 2,397 | 3 | 6 | 177 | 2,391 |
| Navarin Basin (F-G) | * | 2,054 | * | 16 | * | 2,038 |
| Central California (P-G) | 240 | 1,587 | 2 | 4 | 238 | 1,583 |
| Mid-Atlantic (G) | 90 | 897 | 1 | 2 | 89 | 895 |
| St. George Basin (G) | * | 754 | * | 4 | * | 750 |
| Washington-Oregon (P) | 130 | 486 | * | 1 | 130 | 485 |
| Beaufort Sea (F-G) | * | 682 | * | 4 | * | 678 |
| North Atlantic (G) | 17 | 245 | 1 | 1 | 16 | 244 |
| Straits of Florida (VP) | * | 55 | * | * | * | 55 |
| Chukchi Sea (P) | * | 600 | * | 3 | * | 597 |
| Gulf of Alaska (F-G) | * | 36 | * | 1 | * | 35 |
| North Aleutian Basin (G) | * | 26 | * | * | * | 26 |
| Norton Basin (F-G) | * | 34 | * | 1 | * | 33 |
| Kodiak (G) | ** | ** | ** | ** | ** | ** |
| Hope Basin (F) | ** | ** | ** | ** | ** | ** |
| Shumagin (VP) | ** | ** | ** | ** | ** | ** |
| Cook Inlet (G) | ** | ** | ** | ** | ** | ** |

*Estimated to be less than 0.5 million $1987.

**Resources for these areas are estimated to be negligible (see Table 2), thus no production is expected, and social costs are estimated to be less than 0.5 million $1987. (See Table 12.2 for the balancing of benefits and costs of OCS leasing and production for these areas).

/1 See Figure 1 of this SID and Appendix F for the basic assumptions and results of the net economic value analysis and Appendix G for the basic assumptions and results of the social cost analysis. The planning areas are ordered in this table by net economic value @ $24/bbl starting oil price. The high price case uses the $29/bbl starting reference oil price and the low price case uses the $14/bbl starting reference oil price. The $14 and $29 per barrel starting prices are expressed in 1984 dollars, as of the start of this analysis. That range corresponds to a reference price range from $15.75 to $32.50 per barrel as of the start of the new program in mid-1987 (see Table 2).

/2 In parentheses after each planning area is the evaluation of the grid coverage/quality of geologic and geophysical data for regional resource estimates for that planning area: E = Excellent; G = Good; F = Fair; P = Poor; and VP = Very Poor (see Appendix E).

Table 12.2

Balancing of Benefits and Costs
in Low Value Planning Areas /1
($ 1987)

| | Estimated Net Economic Value Per Barrel | Estimated Social Costs Per Barrel |
|---|---|---|
| Cook Inlet | $2.13 | $0.02 |
| Shumagin | 2.52 | 0.01 |
| Kodiak | 2.16 | 0.01 |
| Hope Basin | 1.98 | 0.01 |

/1 This table indicates the estimated balance of costs and benefits for planning areas estimated to have some developable resources, but only negligible leasable resources. Since the balancing analysis presented in Table 12.1 depends on the presence of estimated leasable resources in a planning area, a different method had to be used to estimate the balance of costs and benefits of OCS leasing and production for these four areas.

This table is based on the assumptions that if some or all of the developable resources in these areas were leased, their expected private value (the after-tax net present value for the bidder) would have to be equal to or greater than zero; that--on the low side--private value is equal to zero for each of those planning areas; and that the starting oil price is $29/bbl.

Furthermore, both the total benefits and the costs are the result primarily of the resource potential of an area. There are no areas in which the estimated resource potential is substantial while the estimated costs of environmental damages and adverse impacts on the coastal zone are greater than the estimated leasable resources. Areas estimated to have low resource potential have low benefits and even lower costs. Should such areas turn out to have more oil and gas than estimated, the benefits and the costs would both be higher, but the benefits would exceed the costs. Thus, areas in which the estimated resource potential and estimated economic benefits are low to negligible should not be regarded as areas in which the costs exceed the benefits.

The timing and location of sales in the alternative schedules presented as options in this SID depends on numerous considerations which are discussed in connection with the decision options in Part III of the SID.

The court in California v. Watt (II) (at 599) specifically upheld the scheduling of lease sales on the basis of section 18 interests other than relative net social value alone. Indeed, in this context it should be noted that section 18(a)(3) specifies that one of the three elements to be balanced is "the potential for the discovery of oil and gas" (emphasis added). The great dependence of knowledge about the location and size of oil and gas accumulations on drilling information needs to be recognized in the use of the net social value rankings which are in turn based on resource estimates. Resource estimates generated by the Government and by private parties are subject to substantial uncertainty especially where there is a paucity of seismic and drilling information available for an area (see Appendix E). This makes resource estimates about frontier areas especially uncertain and makes particularly appropriate the use of ranges of data. The collection of seismic data is the first step in the process leading to discovery of oil and gas. It results primarily from investments by firms planning to bid in scheduled lease sales. The scheduling of a sale for a low potential frontier area for which little data are available is one way to expedite a more intensive evaluation of its resource potential. Indeed, one of the purposes of the 1978 OCS Lands Act Amendments is to "insure that the extent of oil and natural gas resources of the OCS is assessed at the earliest practicable time" (section 102(9)). Consequently, although resource estimates are our best indicator of where the search for oil and gas should be focused, it is reasonable not to rely on the resulting net social value calculations alone in scheduling sales in frontier areas.

Planning areas have also been analyzed in terms of relative environmental sensitivity and marine productivity (see Part II.B.3 and Appendix I). These considerations are reflected in the net social value rankings in that they are factored into the social cost estimates. However, since environmental considerations entering into the environmental sensitivity and marine productivity analysis have significant qualitative elements, they need to be reviewed on their own terms as well as insofar as they provide an input to the estimation of net social value.

In addition to being used in the context of the factors discussed above, the net social value estimates are not used directly, but are used as a basis for the formation of groups of areas within a range of estimated net social values, as appears below. Such an approach further guards against overreliance on the absolute values of the net social value estimates, whose limitations have been described above in Part I and in Appendices F, G, and S.

The relative net social value estimates displayed in Table 12.1 can be used to divide the planning areas into the following four groups:

Group I: Areas with the highest NSV across the range of starting oil price cases: Central and Western Gulf of Mexico.

Group II: Areas with positive NSV across the range of starting oil price cases: Southern California; South Atlantic; Mid-Atlantic; Eastern Gulf of Mexico; Central California; Northern California; North Atlantic; and Washington-Oregon.

Group III: Areas with positive NSV in at least the high starting oil price case: Navarin Basin; Chukchi Sea; Beaufort Sea; St. George Basin; Gulf of Alaska; North Aleutian Basin; Norton Basin; and Straits of Florida.

Group IV: Areas with no positive NSV at the high oil price case but estimated to have some developable resources: Kodiak; Hope Basin; Shumagin; and Cook Inlet.

Part III combines considerations based on net social value calculations with the numerous other considerations which bear on the timing and location of sales.

The Secretary will need to consider the conclusions which can be drawn from the net social value estimates collectively with the explanations of those estimates provided in this SID and the qualitative information presented in the SID and the final EIS.

## II.E. Minimum Bid and Bid Adequacy Review Considerations

### Fair Market Value

Section 18(a)(4) of the OCS Lands Act requires the formulation of an OCS oil and gas leasing program consistent with the following principle:

> Leasing activities shall be conducted to assure receipt of fair market value for the lands leases and the rights conveyed by the Federal Government.

The structure of the lease market for the exchange of these rights between buyers and sellers is established by the OCS Lands Act. The act provides that oil and gas leases are to be sold by competitive sealed bidding and thus establishes a competitive market process which determines the value of OCS oil and gas leases. The decision to accept the high bid is based only on whether it meets MMS bid adequacy requirements, given that the high bidder is qualified to conduct OCS operations. (See Appendix K for a detailed discussion of fair market value.)

In litigation on the 1982 5-year program document, the U.S. Court of Appeals for the District of Columbia Circuit was asked to determine whether the Secretary could meet the statutory requirement "to assure receipt of fair market value for the lands leased and the rights conveyed" by OCS oil and gas leases, in light of the fact that the "accelerated rate of leasing might ordinarily result in less intense competition and lower bids for some tracts." The court ruled that despite the lower bids expected, "the proposed evaluation process, coupled with the Secretary's reasonable reliance on the integrity of the competitive bid process, is sufficient to assure that the fair market value is received. The statute requires nothing more." (See California v. Watt (II) at 608.)

A variety of comments received on the Proposed Program focused on fair market value issues and generally reiterated positions expressed on the Draft Proposed Program. These comments are discussed below and summarized in Appendix B, section B.(7).

- Some commenters, representing State and local governments or environmental groups, believe that fair market value will not be received for leases unless competition is fostered by using a nomination process or by reducing the amount of acreage offered for sale. However, three commenters stated that the Proposed Program procedures are appropriate to assure receipt of fair market value. Several commenters suggested that fair market value for leases would not be received for leases while oil and gas prices are low.

- The Natural Resources Defense Council (NRDC) and others in their comments on the Proposed Program and Draft Proposed Program included concerns about fair market value issues. Specifically, NRDC contends that areawide leasing is not likely to lead to an efficient allocation of resources or the attainment of fair market value for the resources leased. They believe that the decline in bonuses indicates that the Government did not receive fair market value for the resources leased. They attribute this decline to a decrease in competition with areawide leasing, limited resources available to bid and to formulate bids, and the limited information about the tracts offered. Another factor which NRDC believes contributes to the failure to attain fair market value is the Government's use of the cash bonus bid form of auction. NRDC proposes that alternative bidding systems be considered for their roles in ensuring the receipt of fair market value.

NRDC's and others' concerns regarding the revenue effects of past areawide leasing are addressed in Part III.B. (size option) and in Appendix P, which analyzes the tract selection, focused, and areawide leasing approaches.

Based on recent analysis, the Department has found that the effects on competition of alternative bidding systems which were analyzed have been negligible. (See: DOI, MMS: "Outer Continental Shelf Lease Sales Fiscal Years 1978 through 1983, Evaluation of Alternative Bidding Systems," March 20, 1987.)

Minimum Bid and Bid Adequacy Review

All OCS lease sale bids must exceed a minimum level as outlined in the sale announcements. The minimum bid, currently set at $150 per acre (with an opportunity for review on a sale-by-sale basis) represents an across-the-board Government evaluation standard with which all OCS high bids are compared--it provides the initial step in the overall bid adequacy screening process. The competitive sealed bidding process of the OCS lease market is the mechanism which is used to interpret market value at a specific point in time (i.e., a sale). There are circumstances in the OCS lease market which could allow bids to be submitted which, without the exercise of a prudent assessment by the Government, could result in receipt of less than fair market value. Where information asymmetry exists, such as on drainage and development tracts where the adjacent owner has privileged information, or on wildcat and proven tracts that involve development technologies unique or limited to selected companies, the corresponding bid may be skewed and other parties may choose not to bid. In order to assure fair market value as the law requires and the courts have interpreted, the Secretary has developed a set of procedures which reflect an understanding of the workings of the OCS lease market in generating values and bids. The Secretary has structured the procedures to assure receipt of fair market value by relying on the market to generate value and by relying on Government evaluations to assure that market values being generated for certain categories of tracts are indeed fair; otherwise, the high bids are rejected and the tracts reoffered at a later date.

In July 1982, a Departmentwide task force was established to develop and test various methods for determining bid adequacy in light of the Secretary's legal requirement to assure receipt of fair market value in conjunction with the leasing program proposed at that time. In February 1983, the Department adopted the recommended procedures of the task force. The procedures consisted of a two-phase bid adequacy review process which uses tract classification and actual bid data to determine which tracts require detailed analysis. Phase 1 includes market-oriented evaluation criteria for accepting some bids on some blocks and determining which other bids will receive further evaluation in Phase 2. Phase 2 uses tract value estimates from a discounted cash flow model as an important determinant for accepting or rejecting bids.

In 1982, the Department increased the minimum bid from $25 to $150 per acre and provided for reconsideration of the minimum bid level based upon experience. In conjunction with the two-phased bid adequacy review procedures, the minimum bid may help to assure fair market value by substantially increasing the bonus amounts bid on many one-bid tracts.

In 1984 and 1985, modifications were made to the OCS bid adequacy procedures to incorporate knowledge gained from their actual use in areawide lease sales. On the surface, there has been an observable overall decrease in the average bonus bid per acre in recent years. This trend actually began in 1980 in tract selection sales. There has also been an increase in the number of one-bid tracts. Analysis of these observations was made to assess their cause. While the per acre bonus declines have been due to a myriad of factors, the most significant ones appear to be the decrease in the expected price of oil and the overall quality and location of tracts being offered for lease. A 50 percent drop in the world price of oil, along with projections of lower rates of future price growth, have significantly influenced the present value of tracts being offered. Further, the sale and leasing of tracts in and subsequent focused leaseofferings have seen industry moving into deepwater, high-cost areas of mature OCS planning areas and into high-cost frontier areas--a trend which had barely begun when nomination-type sales were held. Market forces are operating to reflect these conditions.

There were numerous comments on the Proposed Program which addressed the minimum bid. The most important are discussed below and summarized in Appendix B.

- Five industry commenters recommended lowering the minimum bid to reflect lower oil and gas price expectations and/or to encourage leasing and development. NRDC commented against reducing the minimum bid. The State of California favors retaining the current minimum bid level at least for tracts in the 8(g) area.

- In comments on the Proposed Program as well as on the Draft Proposed Program, NRDC expressed concern about the Department's ability to do an effective job of evaluating tracts for bid adequacy. They cited and agreed with General Accounting Office (GAO) reports questioning the methodology and existing data bases used in part of the bid screening process./1 MMS' response to these comments as well as other issues raised by NRDC are included in papers cited below which are part of the administrative record for the development of the new 5-year program. 2/

/1 Improvements Needed in the Department of the Interior's Acquisition of Geophysical Data (GAO/RCED-85-9, Nov. 20, 1984)

Interior Has Taken Steps to Improve The Adequacy of Data Used for Making OCS Leasing Decisions (GAO/RCED-85-86, March 26, 1985)

Views on Interior's Comments to GAO Reports on Leasing Offshore Lands (GAO/RCED-86-78 BR)

/2 Interior's responses to Congressman John Dingell (Chairman, Subcommittee on Oversight and Investigations, Committee on Energy and Commerce, House of Representatives) on GAO reports (cited above): June 3, 1986; November 25, 1985; August 1, 1985; June 28, 1985; June 11, 1985; May 17, 1985; May 10, 1985; March 26, 1985; and March 1, 1985.

Response to Selected Topics Raised by NRDC on the Proposed 5-Year OCS Leasing Program, Branch of Economic Studies, Offshore Resource Evaluation Division, December 24, 1986.

Bid adequancy procedures originally adopted in conjunction with areawide leasing have been modified as a result of ongoing analysis of their use. As a result of these modifications, the percentage of tracts passed to "Phase 2" (of the bid adequacy procedures) for detailed evaluation, has increased from 33 percent to about 50 percent. In its March 26, 1985, report, "Interior Has Taken Steps to Improve the Adequacy of Data Used for Making (OCS) Leasing Decisions," the GAO recognized MMS's continuing improvement of its procedures and data for tract evaluation purposes and made no further recommendations. Appendix K includes a complete description of the current bid adequacy review procedures with an explanation of how these procedures help to ensure the receipt of fair market value.

Part of the decision on the Draft Proposed Program was to review the question of whether the minimum bid should be changed either in general or specifically for different planning areas. Alternatively, the question was raised whether enlargement of the maximum tract size would achieve effects comparable to varying the minimum bid. Two of the eight topics presented for comment in the Federal Register Notice of March 22, 1985, pertained to these questions. Comments on the minimum bid question varied:

- There were some general objections to lowering the bid level from the current $150 per acre level. Others recommended that the minimum bid level be adjusted on a planning area basis, to take care of any contingencies that may arise, such as changes in price expectations. Industry commenters generally recommended lowering the minimum bid--especially for high-risk frontier areas or high-cost deepwater areas.

- There was general agreement among commenters concerning the issue of larger tract size. Most commenters favored maintaining the current tract size. A few noted that tract size could be tailored for specific prospects, such as in deepwater or in areas where exploration and development costs are high. A detailed summary of these comments appears in Appendix B of the Proposed Program.

The larger tract size question focuses on the possibility of modifying the current maximum tract size of 5760 acres as a means to stimulate industry activity in high-risk OCS areas by providing a new incentive for industry to explore these areas. The reasoning here is that, in high-risk, high-cost areas, the present tract size may not be appropriate to support investment costs even if a discovery were made. The Secretary has the authority, under section 8(b)(1) of the OCS Lands Act, to increase the maximum tract size (beyond 5760 acres) if a larger area is necessary to comprise a reasonable economic production unit. In general, benefits of larger tract sizes include: a decrease in discovery risk; economies of scale; greater information value; and a reduction in production risk, if a discovery is made. However, there are significant problems associated with increasing tract size, including interpretation and satisfaction of the legal requirement that the additional acreage be employed to obtain a "reasonable economic production unit." Defining a "reasonable economic production unit" could be a complex task.

Another important factor to consider regarding the benefits of offering larger tracts is that what is perceived to be a "reasonable economic production unit," even for a given geologic prospect, is likely to differ among lessees. Therefore, even if the Government could identify a specific structure and define a reasonable economic production unit, lessees may not share the same view. Additionally, the acquisition of the information to assess a unit's economic viability might be time-consuming and costly.

In any case, increasing tract size may not be the most efficient policy instrument with which to provide exploration incentives because unitization is available to help lessees achieve economies of scale in exploration, development, and production. Given the preceding observations and the significant number of public comments (including industry) indicating a preference for tracts no larger than 5760 acres, an option to increase tract size is not presented in this SID. However, as part of MMS' current review of OCS oil and gas leasing policies (as announced in the Federal Register Notice of October 31, 1986), the use of larger tract sizes will again be considered as a possible incentive to encourage leasing exploration and production. If a change in tract size is found to be necessary to comprise reasonable economic production units, MMS would issue a Notice of Sale and offer for lease a selected number of larger tracts.

Additional discussion of minimum bid policy is contained in Part III.C., where decision options are presented for minimum bid and bid adequacy review policy. That section provides a discussion of the effects of the minimum bid level on:

1. bidding and Government receipts;

2. the appropriate timing for the leasing and development of prospects in different OCS areas; and

3. promoting exploration in high-risk/high cost areas.

## Part III Options for the Proposed Final Program

Section 18 provides for three successive stages of development of a new 5-year OCS leasing program prior to final approval. This Proposed Final Program stage is the third of those three.

### III.A. Location and Timing Options for the Proposed Final Program

In the formulation of a leasing program, many location and timing considerations merge. Consequently, this section of the SID presents a number of location and timing issues in combined form.

The first category of location considerations in formulating the Proposed Final Program concerns the selection of a configuration of planning areas, boundaries, and subareas where leasing will not be pursued in the new program. The second category deals with the scheduling of sales in the various planning areas.

The treatment of each major option category will be divided into three sections: options; discussion; and comments.

#### A.1. Planning Area Configuration Options for the Proposed Final Program

Options

Based on further review of planning area configuration and boundary issues, including a review of the comments on the Proposed Program, the following decision options are presented for consideration.

OPTION A.1.a Adopt a modification of the configuration of planning areas, boundaries, and subarea deferrals adopted for the Proposed Program. (This option is subject to modification by the selection of suboption b, c, d, e, f, g, or h below.)

OPTION A.1.b Defer leasing in any or all of the following subareas identified in Alternative 2 of the final EIS:

i. The subareas highlighted for further analysis and comments in the Proposed Program, revised as indicated by underlining:

(A) Three subareas extending 15 nautical miles (n. mi.) offshore, or, where further offshore, to the limit of low hydrocarbon potential as estimated by MMS in the North, South, and Mid-Atlantic planning areas

(B) The Gulf of Maine, north of 42°30' N. latitude

(C) The National Aeronautics and Space Administration Flight Clearance Zone offshore Cape Canaveral (extending to 195 n. mi. offshore), south of 31° N. latitude

(D) A subarea extending between 20 and 30 n. mi. offshore the Florida Gulf Coast from Apalachicola to State waters north of the Keys at approximately 82° W. longitude, adding to it 15 blocks in the "Gainesville" official protraction diagram (OPD) and removing from it 6 blocks in the "Pulley Ridge" OPD

(E) Four subareas seaward of approximately the westernmost continuous 1,000 meter isobath in the Washington-Oregon, Northern California (seaward of the Sale 91 area), Central California, and Southern California planning areas

(F) Two subareas totaling 210 blocks adjacent to Unimak Pass in the St. George Basin and the North Aleutian Basin planning areas offshore Alaska

(G) A subarea of 59 blocks offshore Point Barrow, Alaska, in OPD NR 4-2

ii. The congressional moratorium area in the North Atlantic
iii. Looe Key National Marine Sanctuary
iv. Key Largo National Marine Sanctuary
v. A subarea from Apalachicola to Panama City
vi. A subarea 20-30 n. mi. offshore in the Dry Tortugas OPD
vii. A subarea approximately 10.5 n. mi. (12 statute miles) offshore the Yukon Delta in the Norton Basin (101 blocks)

c. Defer subareas per the California Governor's Proposal of 5/7/86

d. Defer subareas per the Regula Proposal re: offshore California (through mid-1992)

e. Defer subareas per the Panetta Proposal re: offshore California (through mid-1992)

f. Defer subareas per the Institute for Resource Management Bering Sea Proposal of 5/8/86

g. Defer subareas per the Draft Proposed Final Program amalgamated proposal for the OCS offshore California

h. Highlight some or all of the subareas considered for deferral at the 5-year program stage for consideration during the presale process.

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Discussion of Planning Areas and Subareas

-Planning Areas

--General

The development of a new 5-year program calls for the consideration afresh of the whole OCS. The configuration of planning areas rests on a number of considerations: geological and geophysical data; leasing, exploration, development, and production history; environmental data; coordination with coastal governmental entities; mapping considerations; jurisdictional claims to the OCS and the Exclusive Economic Zone (EEZ); and administrative factors.

The U.S. Circuit Court of Appeals for the D.C. Circuit has upheld the phased nature of OCS decisionmaking, with the broadest decisions affecting whole planning areas to be made at the 5-year program stage and more specific decisions within planning areas to be made in the presale process.

This "pyramidic" process was recognized by the court in the following terms:

> . . . The 1978 amendments [to the Act] outlined a five step process for achieving . . . expeditious but orderly development [of the OCS]. The first step is the adoption of a five-year leasing program which contains a proposed schedule of lease sales. This is followed by sale of the leases, exploration, development and production, and ultimately, sale of the recovered minerals. The five step process is "pyramidic in structure, proceeding from broad-based planning to an increasingly narrower focus as actual development grows more imminent." Additional study and consideration is required before each succeeding step is taken. Thus, while an area excluded from the leasing program cannot be leased, explored, or developed, an area included in the program may be excluded at a later stage. /1

While several commenters stated that too much acreage is contained in planning areas, the size of the planning areas needs to be seen in the perspective of the pyramidic nature of the OCS leasing process.

This SID presents examples of progressive reductions in the size of areas under consideration for leasing through the presale process (see Part III.B and Appendix O). In addition to the presale process, the deferral of leasing in portions of planning areas ("subareas") at the 5-year program stage can reduce the size of acreage available for leasing.

A further consideration concerning the proper size of planning areas relates to Interior's ability to perform an adequate environmental assessment of lease sales proposed within them. This issue was examined in the GAO Report, "Early Assessment of Interior's Area-Wide program for Leasing Offshore Lands." The GAO there summarized the results of a survey of oil and gas companies, coastal States, and national environmental and fishery groups. The GAO concluded that most regarded Interior's planning documents for presale decisions as accurate and complete. Furthermore, most of those questioned believed that the time for review and comments was adequate. This Report thus supports the point that a planning area need not be limited to one kind of environmental regime in order to be analyzed adequately in an EIS. This issue, and others related to sale size, are discussed further in Part III.B.

In terms of environmental analysis, both the programmatic and sale-specific EIS processes are capable of analyzing the environmental effects of leasing in both shallow and deep water areas. For the decision on the Proposed Final Program, the Secretary will have the benefit of the analysis in the programmatic EIS. Likewise, it is not necessary to limit a planning area by water depth. The economic analysis in Appendix F of the SID explains how different water depths are considered with respect to sale-specific bidding systems and lease terms.

It also needs to be considered that if OCS acreage were divided into more planning areas and offered at the same rate, more separate sales would be required. The result could be an increase in the OCS sale document review burden of affected States and localities.

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/1 California v. Watt (II) 712 F.2d at 588

--Planning Area Options

Option A.1.a provides for the confirmation of the planning areas, boundaries, and subarea deferrals adopted for the Proposed Program, except that it would extend the boundaries of four planning areas: Western, Central, and Eastern Gulf of Mexico; and Straits of Florida (see Map 3). This revision would make the added area avaliable for consideration for leasing in the new 5-year period, given the historic trend toward drilling in ever deeper waters in the Gulf of Mexico. In addition, the Department of State has made minor revisions to planning area outer boundary descriptions (final planning area boundaries are described in Appendix N). The other elements of this option are unchanged from the decision of the Secretary on the Proposed Program. These elements include the division of the entire OCS into 26 planning areas which are basically similar to the areas adopted for the 1982 program, except for the following new features: the planning areas offshore California were reconfigured from two to three; a separate planning area was established for the Straits of Florida; 2 newly-approved official protraction diagrams (OPDs NH 18-4 and NH 18-7) were added to the South Atlantic; the Beaufort Sea planning area was extended to include OPD NS 7-8; the Eastern Gulf of Mexico planning area was extended to include OPD NG 16-5 and OPDs south of 26° N. latitude (NG 17-8 ["Miami"], NG 17-10 ["Dry Tortugas"], NG 16-12, and the northwest corner of NG 17-11 ["Key West"]); and 128° W. longitude was proposed as the seaward boundary for the new Northern California and Washington-Oregon planning areas.

The reconfiguration of planning areas offshore California adopted in the Draft Proposed Program (March 1985) and confirmed in the Proposed Program (February 1986) resulted in the following boundaries:

1. Southern California--the offshore area from the provisional boundary with Mexico north to the San Luis Obispo County/Monterey County line, between block rows N825 and N826. This would merge the Santa Maria portion of the 1982 program's Central/Northern California area into the present Southern California area. This new area would border approximately 436 miles of mainland coastline.

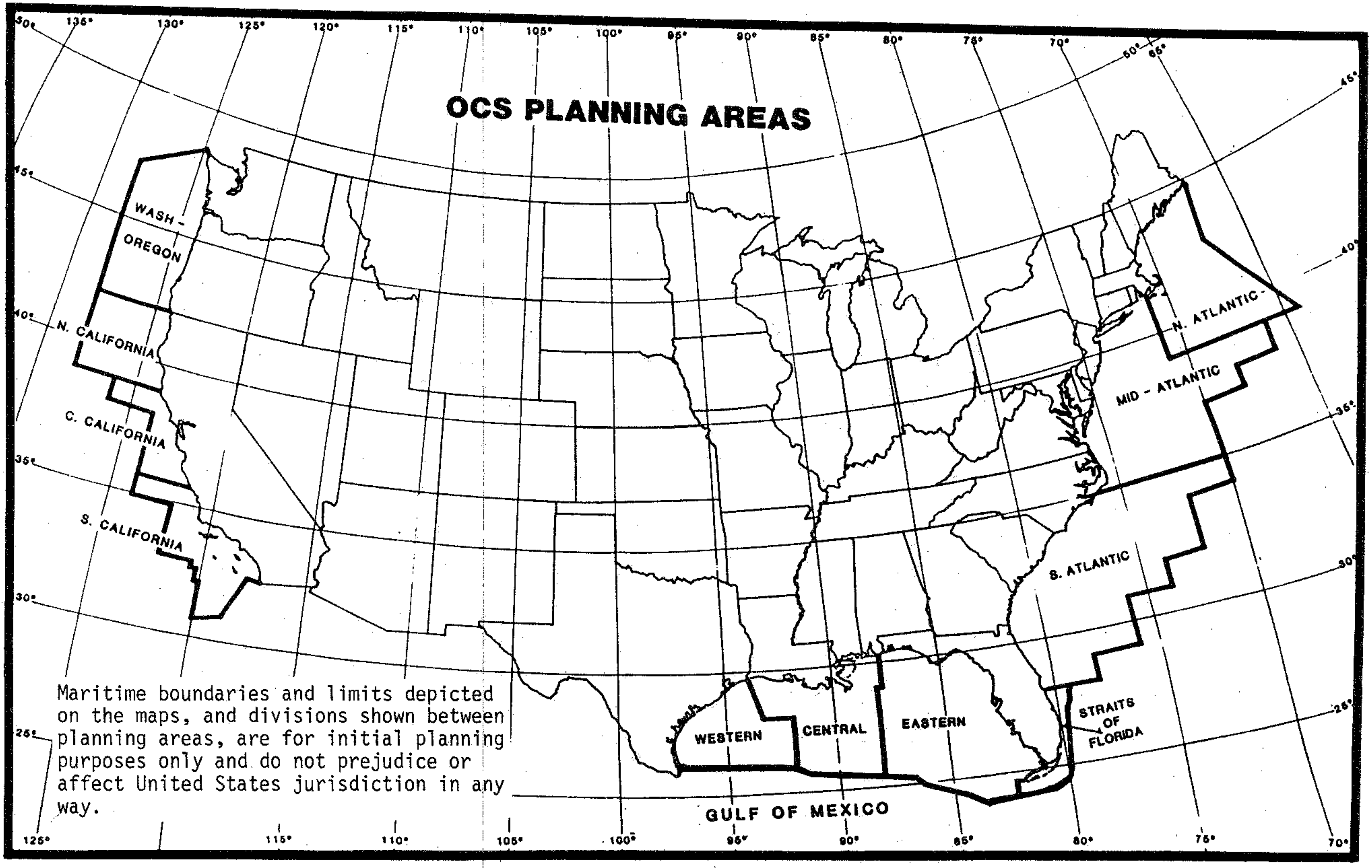
2. Central California--The offshore area north of the San Luis Obispo County/Monterey County line to the Sonoma County/Mendocino County line, between block rows N894 and N895. This new area would include two basins and would border approximately 350 miles of mainland coastline.

3. Northern California--the offshore area north of the Central California area to the California/Oregon border. This new area would include the two northernmost basins and would border approximately 286 miles of mainland coastline.

The March 1985 California planning area reconfiguration responded to several concerns noted in comments received in response to the July 1984 request for comments on the development of a new 5-year program. The reconfiguration into three areas combines all existing OCS oil and gas operations within the Southern California planning area. This combination facilitates a more realistic and accurate cumulative analysis of environmental effects of OCS activities, including air quality and transportation of oil and gas. In conjunction with the leasing schedule proposed in March 1985, this change facilitated the reduction of the frequency of OCS lease sales in each new planning area from one sale every other year to one sale every third year. The reconfiguration responds in part to recommendations from the State of California and local governments to divide the OCS planning areas into more

Map 3

Option A.1.a Revision of Gulf of Mexico Boundaries




Maritime boundaries and limits depicted on the maps, and divisions shown between planning areas, are for initial planning purposes only and do not prejudice or affect United States jurisdiction in any way.

manageable areas than the two in the 1982 program (Central/Northern and Southern California). Those two areas contained approximately 780 and 292 miles of mainland coastline, respectively.

In the Draft Proposed Program and the Proposed Program, the seaward boundary of the Northern California and Washington-Oregon planning areas was set at 128° W longitude so as to include the official production diagrams comprising the full area of hydrocarbon potential as estimated by MMS. The addition of the Eastern Gulf of Mexico area in the vicinity of the Florida Keys, south of 25° N latitude and east of 82° W longitude, adds to the program an area of hydrocarbon potential. While comments raised questions about these areas, they are retained in the basic configuration of planning areas for this option. Both the subarea deferral option and the presale process for specific sales provide ways of addressing objections to offering for lease acreage of concern to commenters.

-Subareas

Section 18(f)(1) of the OCS Lands Act provides the basis for the Secretary's consideration of "nominations for any area to be offered for lease or to be excluded from leasing." Requests for deferral of about 100 specific geographic subareas or categories of subareas as part of the new 5-year program have come from a variety of parties. Appendix B lists all requests for deferral by States, localities, and other parties received in comments on the Proposed Program. In addition, an attachment to this SID describes individually or in combined form virtually all subareas nominated for deferral in response to either the July 1984, March 1985, or February 1986 Federal Register Notices on the new 5-year program as well as a number of Department of Defense and National Aeronautics and Space Administration use areas. That attachment describes the environment of each subarea, its resource potential, data on leasing history and industry interest, and the impacts which might be avoided were the subarea to be deferred from leasing in the new program.

--Advantages and Disadvantages of Subarea Deferrals at the 5-Year Program Stage

On one hand, removing high conflict areas at the earliest stage of the leasing process could reduce controversy and litigation over them. In addition, deferral of portions of planning areas could reduce the analysis burden in the presale process for all parties.

On the other hand, the Secretary has discretion to defer the decision on whether to exclude subareas from leasing to the presale process stage for particular sales. That approach would conform to the pyramidic nature of the leasing process in which only the broadest decisions are made at the programmatic stage.

The fundamental approach to the resolution of conflicts over which areas should be offered for lease has been and will continue to be the processes specified in section 19 of the OCS Lands Act, the National Environmental Policy Act, and other applicable laws and regulations. These processes provide for detailed analysis and consultation undertaken in the presale process for individual lease sales. Appendix L describes this process in detail.

Subarea deferrals can short-circuit the extensive presale planning process--including environmental analysis and consultation--and can remove the possibility of reaching sale-specific accommodations and safeguards that could allow offering areas of concern.

Deferrals may be premature and may unduly limit flexibility if made before the availability of the geological and environmental information usually gathered during the presale process for a sale.

Subarea deferrals made at the 5-year program stage cannot be reconsidered for leasing for 5 years (unless a new 5-year program is developed--a multi-year process). This could have a dampening effect on information-gathering in areas which are deferred. Thus, subarea deferrals may, effectively, become permanent.

Section 18 is basically designed to compare whole planning areas. No subarea deferrals from the midst of planning areas were made in the 1980 or 1982 programs. However, as a result of the consultation process prescribed by section 18 of the OCS Lands Act, the Secretary determined that a departure from the practices of the past was warranted in certain locations.

--Criteria for the Secretary's Decisions on Subarea Deferrals

Subsections 18(c), (d), and (f) of the OCS Lands Act provide a basis for Secretarial discretion in responding to subarea deferral recommendations by public commenters. The criteria for Secretarial decisions on such recommendations are those set forth by section 18 of the Act. Section 18 provides for the exercise of judgment by the Secretary based on a consideration of the following: national energy needs; oil and gas resource potential; the potential for environmental harm; the equitable sharing of developmental benefits and environmental risks among the various regions; other uses of the sea and seabed; the interest of potential oil and gas producers; laws, goals, and policies of affected States; and relative environmental sensitivity and marine productivity.

In making his decision concerning subarea deferrals, the Secretary determined that the uniqueness of the subareas required the exercise of judgment on a case-by-case basis rather than the application of an abstract formula or inflexible guidelines. In making his decision on the Proposed Program, the Secretary was provided with the key characteristics of over 100 subareas requested by commenters for deferral from leasing and a number of areas with other uses identified by MMS. Those characteristics included the disposition of the subarea in past OCS lease sales, oil and gas resource potential, description of the environment, and description of the potential impacts avoided by the deferral of leasing.

Making a judgment based on those considerations, the Secretary proposed the deferral of leasing in 15 subareas as part of the Proposed Program and selected 13 other subareas to be highlighted for further comments and analysis. The final decision on subarea deferrals will be made only when final approval is given to the new program.

Based on a consideration of comments on the Proposed Program and the other considerations identified above, in Fall 1986, the Assistant Secretary for Land and Minerals Management made adjustments to SID options and EIS alternatives, including the 13 highlighted subareas. Table 12.3 displays the subareas deferred or highlighted in the Proposed Program and the Fall 1986 adjustments to the options.

Table 12.3

Subarea Deferral Options

| | Proposed Program Proposal | Proposed Final Program Option |
|---|---|---|
| I. Subareas with Federal legal restrictions affecting OCS oil and gas activities | | |
| A. Statutory: | | |
| 1. OCS Lands Act section 11(h) re: offshore Point Reyes Wilderness Area | Defer | Defer |
| 2. North Atlantic Moratorium Area | - | Defer |
| B. Federal regulations and orders: | | |
| 1. National Marine Sanctuaries on the OCS | | |
| a. Point Reyes - Farallon Islands National Marine Sanctuary | Defer | Defer |
| b. Channel Islands National Marine Sanctuary | Defer | Defer |
| c. Gray's Reef National Marine Sanctuary | Defer | Defer |
| d. U.S.S. Monitor National Marine Sanctuary and Buffer Zone | Defer | Defer |
| e. Looe Key National Marine Sanctuary | - | To be deferred if a sale is scheduled in Straits of Florida |
| f. Key Largo National Marine Sanctuary | - | |
| 2. Santa Barbara Federal Ecological Preserve and Buffer Zone | Defer | Defer |
| II. Subareas comprising large contiguous areas estimated by MMS to have negligible hydrocarbon potential | | |
| A. Washington-Oregon | Highlight | Defer subareas expanded to seaward of approx. the westernmost continuous 1,000 meter isobath in all four Pacific planning areas |
| B. Northern California | Highlight | |
| C. Central California | Highlight | |
| D. Southern California | - | |
| E. Gulf of Maine | Highlight | Defer |
| III. Subareas with some estimated hydrocarbon potential where environmental concerns have been expressed | | |
| A. Cordell Bank | Defer | Defer |
| B. Offshore Monterey Bay | Defer | Defer |
| C. Offshore Big Sur | Defer | Defer |

| | | Proposed Program Proposal | Proposed Final Program Option |
|---|---|---|---|
| D. | Seagrass Beds | Defer | Defer |
| E. | Florida Middle Ground | Defer | Defer |
| F. | Atlantic Coast portion of Straits of Florida | Defer | Defer |
| G. | Flower Garden Banks | Defer | Defer |
| H. | Atlantic Coast subareas (15 nautical [n.] miles) | Highlight | Defer subarea extended to include certain low potential areas beyond 15 n. miles |
| I. | 20-30 nautical mile subarea off the Florida Gulf Coast | Highlight | Defer subarea, |
| J. | "Miami" OPD area off the Florida Gulf Coast | Highlight | revised to add 15 blocks in the "Gainesville" OPD, merge with "Miami" OPD, remove 6 blocks in the "Pulley Ridge" OPD, and extended south to State waters at approx. 82° W. longitude |
| K. | Offshore Unimak Pass, Alaska | Highlight | Defer |
| L. | 59 blocks offshore Point Barrow, Alaska | Highlight | Defer subarea (clarify that 59 blocks all in OPD NR 4-2) |
| M. | Subarea from Apalachicola to Panama City | - | Defer |
| N. | ~~Subarea 20-30 n. miles north and west of the Dry Tortugas~~ | - | ~~Defer~~ |
| O. | California Governor's Proposal of 5/7/86 | - | Defer |
| P. | Regula deferral proposal re: offshore California | - | Defer |
| Q. | Panetta deferral proposal re: offshore California | - | Defer |
| R. | Amalgamated proposal re: offshore California | - | Defer |
| S. | IRM Bering Sea proposal of 5/8/86 | - | Defer |
| T. | 12 miles off Yukon Delta | - | Defer |

IV. Subareas with some estimated hydrocarbon potential where concerns have been expressed about other ocean uses

| | | | |
|---|---|---|---|
| A. | Offshore San Francisco Bay | Defer | Defer |
| B. | San Nicolas Navy Operating Area | Defer | Defer |
| C. | NASA Flight Clearance Zone off Cape Canaveral | Highlight | Defer subarea extended to 195 n. miles, n. boundary clarified as 31° N. latitude |

The Fall 1986 adjustment of the list of highlighted subareas reflects the consideration of comments in a way that provides for consistent treatment of subareas recommended for deferral--insofar as possible, considering the unique characteristics of each area. Two proposals submitted by the members of the special Congressional panel concerning the California OCS, as well as the recommendation of the Governor of California, have been included among the potential subarea deferral areas analyzed quantitatively in the SID insofar as they affect leasing through mid-1992.

With the addition of Looe Key and Key Largo National Marine Sanctuaries, and the North Atlantic Moratorium Area, Category I includes all subareas on the OCS with Federal legal restrictions affecting oil and gas activities. The option added for the PFP (deferral of the two national marine sanctuaries in case a Straits of Florida sale is scheduled) would provide for consistent treatment of all such areas on the OCS.

Category II has been revised so that all large, contiguous areas estimated by MMS to have negligible potential for oil and gas resources can be considered for deferral. The adjustment of the subarea line to approximately the westernmost continuous 1,000 meter isobath reflects an accommodation of MMS's estimates of negligible potential beyond that line and the recommendations of the Governors of the Pacific coast States. The extension of the 1,000 meter isobath line through the Southern California planning area provides for consistency in treatment along the entire west coast. Small, scattered areas estimated to have negligible hydrocarbon potential, however, (such as in the Shumagin planning area) are not included in this category because they are interspersed with areas estimated to have potential. The basis for this approach is the pyramidic structure of the leasing process upheld by the court which allows further consideration of whether to defer leasing in particular subareas in the individual presale process.

Categories III and IV call for the greatest exercise of judgment on the part of the Secretary. Analyses to be considered for the decision on the 5-year program are found in the EIS and the Subarea Attachment. The latter contains a quantitative analysis of the deferral of leasing in SID option subareas in addition to the qualitative analysis given to virtually all subareas recommended for deferral.

In order that the Secretary's decision be based on a consideration of the balancing of costs and benefits of leasing and exploration in a way that reflects the potential deferral of subareas from leasing, the quantitative analysis has been augmented in the following way. Leasable resources were recalculated for the remainder of each planning area assuming the deferral of the 15 subareas whose deferral was adopted in the Proposed Program. This resulted in a new base against which to compare the possible deferral of other subareas. For each planning area, a calculation was done of the leasable resources remaining available for leasing assuming the deferral of each subarea. A cumulative figure reflecting the deferral of all subareas within a planning area is also provided in order to reflect the range of possible effects of deferrals. A separate cumulative figure is necessary because, given the nature of the resource estimating model, the cumulative effect of deferrals cannot be estimated by simply adding the effects of the individual deferrals. In order to keep the analysis within reasonable bounds, computations of the effect of the other numerous possible combinations of deferrals within a planning area have been omitted. In the case of California planning areas, a lowest figure is given instead of a cumulative one because the deferral proposals are alternative rather than additive.

The basic calculations are those done for the estimates of leasable oil and gas resources and their net economic value. Social costs are adjusted by multiplying leasable resources by the planning area per-barrel social cost coefficients (see Appendix G). The social cost coefficients were revised for these calculations only to reflect the change in resources available for leasing in the remainder of the planning area after deferrals. For example, even though coastal deferrals would put a minimum distance between potential platform oil spills and sensitive coastal resources, the social cost coefficients have not been reduced on this account. This is because the whole planning area (even the deferred portion) still has the potential for being affected by production which could occur in that part of the planning area which remains available for leasing. It should be noted that this procedure can be interpreted to result in an overstatement of social costs. Similarly, marine productivity/environmental sensitivity rankings for whole planning areas continue to be used in computing social costs. In order to shed more light on the implications of subarea deferrals for the Secretary, however, alternative analyses have been added in Appendices G and I on the potential effects on those analyses of various subarea deferral alternatives.

Net social value estimates for whole planning areas and the remainder of planning areas reflecting subarea deferrals appear in Table 12.4. For the purpose of estimating the effects of subarea deferrals on net social value calculations for the Proposed Final Program decision, technical data have been further reviewed and refined. The equitable sharing analysis (Part II.C) has also been revised to show a range corresponding to the subarea deferral options.

In a number of cases, deferral of leasing in subareas does not materially change the estimates of resources available for leasing or the net social value of leasing and production of the resources in the remainder of the planning area. However, because of the uncertainties inherent in the projection of undiscovered resources and their future value, it should not necessarily be concluded that leasing in such subareas has no potential value (see Appendices F and S).

Comments on Planning Areas and Subareas

-General

° State Governors: Alabama and Maine recommended that subarea deferral decisions be governed by a set process based on scientific and economic criteria. Massachusetts stated that economic and environmental analyses conducted in the development of the 5-year program should eliminate portions of planning areas from leasing. Rhode Island recommended that the option to defer subareas other than marine sanctuaries be exercised with a measure of restraint.

° State Agencies: The California Department of Justice stated that the Secretary's criteria for making deferrals are too vague. The New York Department of Environmental Conservation expressed concern that the Secretary did not use a consistent process for considering subarea deferrals. The Georgia Department of Natural Resources stated that the concept of subarea deferrals is acceptable for the protection of sensitive areas as long as serious consideration is given to other environmentally sensitive areas during the presale process.

° Federal Agencies: The Environmental Protection Agency (EPA) endorsed the proposed deferral of 15 subareas and recommended the deferral of the 13 highlighted subareas. The Department of Energy (DOE) stated that decisions to delete or defer consideration of particular subareas should be made during the presale process rather than at the program stage.

Table 12.4

Range of Estimated Net Social Value of Total Production of Unleased, Undiscovered OCS Oil and Gas Leasable Resources as of Mid-1987 by Planning Area, Reflecting Subarea Deferrals through Mid-1992 /1

| Planning Area | Net Social Value ($MM1987) Low Price Case | High Price Case |
|---|---|---|
| I. North Atlantic | | |
| A. Whole Planning Area | 16 | 244 |
| B. Remainder (No Subareas Were Proposed for Deferral in the Proposed Program) | N/A | N/A |
| C. Whole Area Minus | | |
| (1) 15 n. miles plus low potential areas | 14 | 228 |
| or (2) Gulf of Maine | 16 | 244 |
| or (3) Congressional moratorium area | 9 | 164 |
| or (4) Cumulative of 1, 2, and 3 | 9 | 158 |
| II. Mid-Atlantic | | |
| A. Whole Planning Area | 89 | 895 |
| B. Remainder (Whole Planning Area Minus U.S.S. Monitor National Marine Sanctuary and Buffer Zone) | ---Same as II.A--- | |
| C. Remainder Minus | | |
| (1) 15 n. miles plus low potential areas | ---Same as II.A--- | |
| III. South Atlantic | | |
| A. Whole Planning Area | 430 | 3,439 |
| B. Remainder (Whole Planning Area Minus Gray's Reef National Marine Sanctuary) | 398 | 3,152 |
| C. Remainder Minus | | |
| (1) 15 n. miles plus low potential areas | 398 | 3,152 |
| or (2) NASA Flight Clearance Zone (South of 31° N. latitude, to 195 n. mi.) | 241 | 2,148 |
| or (3) Cumulative of 1 and 2 | 241 | 2,148 |
| IV. Straits of Florida | | |
| A. Whole Planning Area | * | 110 |
| B. Remainder (Whole Planning Area Minus Atlantic coast subarea) | * | 55 |
| C. Remainder Minus | | |
| (1) Looe Key and Key Largo National Marine Sanctuaries | ---Same as IV.B--- | |

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/1 For each planning area, item "B," "Remainder," reflects deferrals from leasing included in the Secretary's February 1986 Proposed Program. Item "C" reflects the further deferral of subareas highlighted for analysis in the Proposed Program, as revised by the Assistant Secretary for Land and Minerals Management in Fall 1986. The net social value figures are estimates of the net present value of all leasable resources available for leasing based on the assumption that all are leased in mid-1987 and produced over timeframes typical for each region. For the effects of the phasing provisions of California proposals, see Table 17.3 and the California Analysis document.

* Negligible (less than $0.5 million in $1987)

Table 12.4 (continued)

| Planning Area | | Net Social Value ($MM1987) Low Price Case | High Price Case |
|---|---|---|---|
| V. | Eastern Gulf of Mexico | | |
| | A. Whole Planning Area | 177 | 2,391 |
| | B. Remainder (Whole Planning Area Minus Seagrass Beds and the Florida Middle Ground) | ---Same as V.A--- | |
| | C. Remainder Minus | | |
| | (1) Revised 20-30 n. mi. subarea (including Miami OPD) | ---Same as V.A--- | |
| | or (2) Apalachicola to Panama City subarea | ---Same as V.A--- | |
| | or (3) Dry Tortugas OPD subarea | ---Same as V.A--- | |
| | or (4) Cumulative of 1, 2, and 3 | ---Same as V.A--- | |
| VI. | Western Gulf of Mexico | | |
| | A. Whole Planning Area | 7,171 | 31,448 |
| | B. Remainder (Whole Planning Area Minus Flower Garden Banks) | ---Same as VI.A--- | |
| VII. | Southern California | | |
| | A. Whole Planning Area | 2,221 | 9,053 |
| | B. Remainder (Whole Planning Area Minus Barbara Federal Ecological Preserve and Buffer Zone; Channel Islands National Marine Sanctuary; and the Coordinated Anti-submarine Warfare Area (San Nicolas Basin)) | 982 | 4,990 |
| | C. Remainder Minus | | |
| | (1) 1,000 meter isobath subarea | 978 | 4,932 |
| | or (2) Amalgamated Proposal of 2/87 | 850 | 4,548 |
| | or (3) California Governor's Proposal | 623 | 3,066 |
| | or (4) Regula Deferral Proposal | 846 | 4,530 |
| | or (5) Panetta Deferral Proposal | 710 /1 | 3,804 /1 |
| VIII. | Central California | | |
| | A. Whole Planning Area | 353 | 2,659 |
| | B. Remainder (Whole Planning Area Minus the area off Pt. Reyes Wilderness, the Pt. Reyes-Farallon Islands National Marine Sanctuary, the area offshore San Francisco Bay, the area in the immediate vicinity of Cordell Bank, the area offshore Monterey Bay, and the area offshore Big Sur) | 238 | 1,583 |
| | C. Remainder Minus | | |
| | (1) 1,000 meter isobath subarea | 235 | 1,543 |
| | or (2) Amalgamated Proposal of 2/87 | 230 | 1,542 |
| | or (3) California Governor's Proposal | 150 | 1,035 |
| | or (4) Regula Deferral Proposal | 222 | 1,501 |
| | or (5) Panetta Deferral Proposal | 45 /1 | 308 /1 |

/1 While these estimates for the Panetta Proposal reflect resources in all areas available for leasing under it, the phasing element of the Panetta proposal would restrict access to them.

Table 12.4 (continued)

| Planning Area | Net Social Value ($MM1987) Low Price Case | High Price Case |
|---|---|---|
| IX. Northern California | | |
| A. Whole Planning Area | 464 | 2,700 |
| B. Remainder (No Subareas Were Proposed for Deferral in the Proposed Program) | N/A | N/A |
| C. Whole Area Minus | | |
| (1) 1,000 meter isobath subarea | 467 | 2,573 |
| or (2) Amalgamated Proposal of 2/87 | 399 | 2,246 |
| or (3) California Governor's Proposal | 342 | 2,163 |
| or (4) Regula Deferral Proposal | 289 | 1,652 |
| or (5) Panetta Deferral Proposal | 31 /1 | 439 /1 |
| X. Washington-Oregon | | |
| A. Whole Planning Area | 130 | 485 |
| B. Remainder (No Subareas Were Proposed for Deferral in the Proposed Program) | N/A | N/A |
| C. Whole Area Minus | | |
| (1) 1,000 meter isobath subarea | ---Same as X.A--- | |
| XI. St. George Basin | | |
| A. Whole Planning Area | * | 750 |
| B. Remainder (No Subareas Were Proposed for Deferral in the Proposed Program) | N/A | N/A |
| C. Whole Area Minus | | |
| (1) Unimak Pass subarea | ---Same as XI.A--- | |
| or (2) Institute for Resource Management Proposal | * | 663 |
| or (3) Cumulative of 1 and 2 | ---Same as XI.C(2)--- | |
| XII. North Aleutian Basin | | |
| A. Whole Planning Area | * | 26 |
| B. Remainder (No Subareas Were Proposed for Deferral in the Proposed Program) | N/A | N/A |
| C. Whole Area Minus | | |
| (1) Unimak Pass subarea | ---Same as XII.A--- | |
| XIII. Norton Basin | | |
| A. Whole Planning Area | * | 33 |
| B. Remainder (No Subareas Were Proposed for Deferral in the Proposed Program) | N/A | N/A |
| C. Whole Area Minus | | |
| (1) Offshore Yukon Delta (101 blocks) | ---Same as XIII.A--- | |
| or (2) Institute for Resource Management Proposal | * | 17 |
| or (3) Cumulative of 1 and 2 | ---Same as XIII.C(2) | |

/1 While these estimates for the Panetta Proposal reflect resources in all areas available for leasing under it, the phasing element of the Panetta proposal would restrict access to them.

Table 12.4 (continued)

| Planning Area | Net Social Value ($MM1987) Low Price Case | High Price Case |
|---|---|---|
| XIV. Navarin Basin | | |
| A. Whole Planning Area | * | 2,038 |
| B. Remainder (No Subareas Were Proposed for Deferral in the Proposed Program) | N/A | N/A |
| C. Whole Area Minus | | |
| (1) Institute for Resource Management Proposal | ---Same as XIV.A--- | |
| XV. Beaufort Sea | | |
| A. Whole Planning Area | * | 678 |
| B. Remainder (No Subareas Were Proposed for Deferral in the Proposed Program) | N/A | N/A |
| C. Whole Area Minus | | |
| (1) Point Barrow subarea | ---Same as XV.A--- | |

° Industry: A majority of commenters endorsed the proposed configuration of the 26 planning areas. Several commenters expressed opposition to the concept of deferring subareas at the 5-year program stage, stating that such decisions should be made during the presale process conducted for individual sales.

° Environmental and Other Organizations: The Natural Resources Defence Council (NRDC) and Maine Audubon Society endorsed the concept of deferring subareas at the 5-year program stage, but noted a lack of set criteria to govern deferral decisions. NRDC also stated that the subarea deferrals proposed are far too limited. Manasota 88 called for the establishment of explicit criteria to guide selection of subarea deferrals.

-Atlantic

° State Governors: Maine recommended deferral of the Gulf of Maine subarea. Maine also stated it was not requesting deferral of Georges Bank; but, if high conflict is a criterion for deferring subareas, then Georges Bank would qualify. Massachusetts recommended that the Gulf of Maine, the Georges Bank region to 400 meters, and submarine canyon areas be deferred. Rhode Island recommended establishment of an administratively flexible boundary between the North and Mid-Atlantic planning areas to allow States involved in both areas to participate fully in the OCS program. Rhode Island also commented that 15 miles is the lowest distance requested by Atlantic States for a coastal deferral and may not be sufficient. Connecticut recommended that the proposed subarea within 15 nautical miles of the Atlantic coast be expanded to 50 miles with specific industry nominations evaluated on a tract-by-tract basis within the subarea. New Jersey commented that deferral of a subarea within 40-50 miles of the coast might be more appropriate than deferral within 15 miles. Delaware commented that a boundary conforming to the geological division between the Baltimore Canyon trough and the Georges Bank basin would form a more appropriate border between the Mid-Atlantic and North Atlantic planning areas than that proposed; and endorsed deferral of the subarea extending 15 nautical miles from the coast. Virginia requested deferral of areas within 50 miles of the coast and areas in offshore canyon heads. Maryland commented that a more reasonable alternative to the 15 nautical-mile subarea would be an arbitrary distance of 30 miles from shore. North Carolina endorsed the proposed deferral of the U.S.S. Monitor Marine Sanctuary and adjacent buffer zone. North Carolina also requested deferral of the area extending seaward to the 200-meter isobath. Florida expressed support for the proposed deferral of the Atlantic portion of the Straits of Florida planning area. Florida also commented that deferral of a buffer subarea off the Atlantic coast should be based on consideration of biological and current regimes, and no informed decision can be made until environmental data are acquired. Florida further recommended deletion of the subarea below 30° N. latitude.

° State Agencies: The Georgia Department of Natural Resources endorsed deferral of the subarea within 15 nautical miles of the coast as long as proposals for alterations of this subarea are evaluated on a case-by-case basis. The Florida Department of Natural Resources endorsed deferral of the Kennedy Space Center Flight Clearance Zone, the subarea within 15 nautical miles of the coast, and the southern portion of the Straits of Florida planning area. The Florida Department of Environmental Regulation endorsed deferral of the Kennedy Space Center Flight Clearance Zone and the subarea within 15 nautical miles of the coast, but noted that the latter may not be sufficient. They also urged permanent deletion of the entire Straits of Florida planning area. The Florida Coastal Resources Citizens Advisory Committee commented in favor of deferring the entire Straits of Florida planning area. The New York Department of Environmental Conservation requested deferral of the area within 50 miles of shore, canyon areas, and the area north of 40° 15' N. latitude. The North Carolina Division of Marine Fisheries and Division of Coastal Management recommended deferral of the area shoreward of the 200 meter isobath. The Virginia Council on the Environment requested that leasing be prohibited within 50 miles of shore and in canyon heads.

° Local Governments: Brevard County (FL) adopted a resolution which endorsed the proposed deferral of the Atlantic coast portion of the Straits of Florida planning area. Brevard County (FL) and Volusia County (FL) endorsed deferral of the Kennedy Space Center Flight Clearance Zone. Brevard also endorsed deferral of the area within 15 miles of the coast. The South Florida Regional Planning Council commented that deferral of the entire Straits of Florida planning area is imperative. The City of Wilmington (NC) adopted a resolution which endorsed the proposed deferral of the U.S.S. Monitor Marine Sanctuary and buffer zone.

° Industry: Chevron commented that it would be appropriate to defer the Atlantic portion of the Straits of Florida planning area, the Gray's Reef Marine Sanctuary, and the U.S.S. Monitor Marine Sanctuary and buffer zone. Murphy Oil commented that the subarea of the Straits of Florida proposed for deferral is excessive and should be reduced to the area within 15 miles of the coast, but that deferral of the other Atlantic, Gulf of Mexico, OCS subareas highlighted for further analysis would be acceptable. API, Phillips, and Exxon expressed opposition to establishment of a separate and distinct Straits of Florida planning area and recommended that it be included in the South Atlantic planning area. Tenneco stated that if a major portion of the Straits of Florida is to be deferred, the remaining area should be included in the Eastern Gulf of Mexico planning area.

° Environmental and Other Organizations: Carteret County Crossroads (NC) endorsed the proposed deferral of the U.S.S. Monitor Marine Sanctuary and buffer zone. Carteret County Crossroads (NC) and Georgia Conservancy requested deferral of the area extending seaward to the 200-meter isobath. The Florida Public Interest Research Group (PIRG) expressed confusion over whether the west coast of the Florida Keys is included in the Eastern Gulf of Mexico or the Straits of Florida planning area. The Association for the Preservation of Cape Cod, Inc. commented that Georges Bank should be deleted from all leasing plans. The Maine Audubon Society requested deferral of the Gulf of Maine.
The Massachusetts Audubon Society requested deferral of Georges Bank and areas shallower than 400 meters, submarine canyons, areas within 50 miles of the coast, and the Gulf of Maine. The League of Women Voters of Massachusetts commented that Georges Bank, the shelf/slope break, and the areas 400 meters or shallower off the Massachusetts coast should be deferred. NRDC recommended deferral of Georges Bank and areas shallower than 400 meters and areas within 50 miles of the Atlantic coast. National Audubon Society (Florida Office), Sierra Club (Florida Chapter), and Friends of Canaveral recommended deferral of the area with 15 miles of the Atlantic coast. Friends of Canaveral also recommended deferral of the Kennedy Space Center Flight Clearance Zone. Florida Defenders of the Environment, Inc. adopted a resolution supporting

permanent deletion of the area in and around the Florida Keys and the Straits of Florida. Florida PIRG recommended deferral of a 30-mile buffer zone around the entire Florida coast.

° Private Citizens: A number of commenters requested deferral of an area ranging within 15 to 50 miles of the coast.

° Congress: Senator Lawton Chiles endorsed deferral of the subareas which the State of Florida requested to be deferred.

-Gulf of Mexico

° State Governors: Florida expressed support for the proposed deferral of 186 blocks in Seagrass Beds and 23 blocks in the Florida Middle Ground. Florida also requested deferral of the subarea between 20 to 30 miles off the Gulf coast from Naples to Apalachicola and asked that 15 blocks in the Gainesville Map area and 97 blocks off Apalachicola Bay, all of which were deleted from Sale 94, be included in this deferral. Florida also stated opposition to leasing in the area south of 26° N. latitude and east of 82° W. longitude.

° State Agencies: Florida Department of Environmental Regulation expressed support for the proposed deferral of blocks in the vicinity of the Florida Middle Ground: Florida Department of Natural Resources requested deferral of the subarea between 20-30 miles off the Gulf coast from Naples to Apalachicola and the Florida Bay area. Florida Department of Environmental Regulation recommended deferral of the subarea between 20-30 miles off the Gulf coast from Naples to Apalachicola and asked that 15 blocks in the Gainesville Map area and 97 blocks off Apalachicola Bay be included in this deferral. They also requested permanent deletion of all areas south of 25° N. latitude and east of 82° W. longitude. Florida Coastal Resources Advisory Committee requested that the area of the Gulf south of 26° N. latitude be deferred. Texas General Land Office expressed support for the proposed deferral of the Flower Garden Banks subarea.

° Local Governments: South Florida Regional Planning Council and Sarasota County recommended deferral of the subarea within 20 to 30 miles of the Gulf coast and the subarea south of 26° N. latitude and east of 82° W. longitude. North Central Florida Regional Planning Council recommended permanent deletion of the subarea within 30 miles of the Gulf coast from Naples to Apalachicola. Southwest Florida Regional Planning Council recommended deferral of the subarea within 30 miles of the Gulf coast from Naples to Apalachicola and the subarea south of 26° N. latitude and east of 82° W. longitude.

° Industry: Tenneco specifically expressed opposition to deferral of the subarea extending 20 to 30 nautical miles offshore from Naples to Apalachicola and the subarea south of 26° N. latitude and east of 82° W. longitude.

° Environmental and Other Organizations: Florida Defenders of the Environment, Inc., adopted a resolution supporting permanent deferral of the subarea south of 26° N. latitude and east of 82° W. longitude and areas in and around the Florida Keys and the Straits of Florida. Izaak Walton League (Region V), Sierra Club (Florida Chapter), and Manasota 88 recommended deferral of the area south of 26° N. latitude. The latter two also recommended deferral of a subarea within 30 miles of the Gulf coast, and Manasota 88 expressed opposition to leasing in Apalachicola Bay. The New Smyrna Beach (FL) Audubon Society and Florida National High Adventure Sea Base recommended deferral of the subarea within 30 miles of the Gulf coast. Greenpeace recommended deferral of the subarea within 50 miles of Florida's Gulf coast and the subarea south of 26° N. latitude. National Audubon Society (Florida Office) called for deferral of the subarea within 20 to 30 miles of the Gulf coast and the area south of 26° N. latitude and 82° W. longitude. NRDC expressed support for deferral of the area within 30 miles of the Florida Middle Ground, the area within 30 miles of the Florida coast from Apalachicola to the Alabama border, and the area south of 26° N. latitude and east of 84° W. longitude. National Audubon Society (Southeast Florida Office) expressed opposition to drilling operations in the OCS between Naples and Key West and within 30 miles of the Gulf of Florida. Seminole Audubon Society requested deferral of the area adjacent to Everglades National Park south of Naples and the area within 15 miles of the Florida Gulf coast from Naples to Apalachicola. Florida PIRG recommended deferral of the subarea within 30 miles of the entire coast of Florida (including 112 Gulf blocks deferred from previous sales) and the area south of 26° N. latitude and east of 82° W. longitude.

° Private Citizens: Several commmenters requested deferral of a subarea ranging from 20-50 miles off Florida's Gulf Coast and deferral of areas of the OCS between Naples and the Keys.

° Congress: Senator Lawton Chiles endorsed deferral of the subareas which the State of Florida requested to be deferred. Congressman C. W. Bill Young endorsed the establishment of a coastal buffer zone identical to the one applied to Sale 94. Congressman William Lehman expressed opposition to leasing in the area south of 25° N. latitude and east of 82° W. longitude. Congressman Dante B. Fascell expressed opposition to leasing around the Florida Keys or in the Straits of Florida.

-Pacific

° State Governors: California endorsed the proposed configuration of the Southern, Central, and Northern California planning areas and added that subarea deferrals would further define these areas and improve the lease sale planning process. They also endorsed deferral of the nine subareas off the State which were identified for deferral in the Proposed Program. California also endorsed deferral of the two subareas off the State which were highlighted for further analysis in the Proposed Program and requested deferral of the following additional subareas: subareas offshore State Areas of Special Biological Significance; all blocks within 3 miles of the seaward boundary of California oil and gas sanctuaries offshore; subareas identified for deferral through prior lease sale analyses (re: Sale 48; Sale 53; Sale 68; Sale 73; and Sale 80); subareas with other resources (the Sea Otter Range, Santa Monica Bay, and off San Diego County); and vessel traffic areas.

Oregon and Washington commented that the proposed Washington-Oregon planning area is too large because it includes areas of no hydrocarbon potential. Oregon also commented that the proposed planning area includes waters which are too deep for leasing. Oregon commented that even if the subarea estimated to be beyond the area of hydrocarbon potential is deferred, the Washington-Oregon planning area still will be too large and will include excessively deep waters. Also, the following areas were requested to be deferred:

- -- Heceta Bank, Stonewall Bank, and Perpetua Bank;
- -- Coquille Banks, southwest of the mouth of the Coquille River;
- -- Oregon Islands National Wildlife Refuge and a 6-mile buffer;
- -- the mouth of the Coos Bay and 6-mile radius buffer;
- -- the mouths of the Columbia River and Yaquina Bay and 6-mile radius buffers; and
- -- Cascade Head and Salmon River Estuary Scenic Research Area and a 6-mile radius buffer.

Washington requested deferral of the area north of the 47th parallel; the areas within 12 nautical miles of the Grays Harbor, Willapa Bay, and Columbia River estuaries; and deepwater areas beyond the continental shelf itself.

° State Agencies: California Department of Justice and Water Resources Control Board endorsed the proposed deferrals of subareas off California. The California Department of Justice also requested deferral of Santa Barbara Channel, Santa Monica Bay, and areas adjacent to Southern Orange County and San Diego County. They also stated that a number of other areas should be deferred, citing the areas off Mendocino County and San Mateo as examples. California Department of Parks and Recreation recommended deferral of State seashores, Areas of Special Biological Significance, the Point Dume-Malibu area, the Bolsa Chica-Huntington Beach area, Crystal Cove State Park Underwater Preserve, and the Carlsbad-International Boundary area.

California Department of Fish and Game recommended that the Santa Maria Basin be included in the Central California planning area or be treated as a separate planning area. They also endorsed the proposed deferral of subareas in the Central California planning area and recommended deferral of areas in the Southern California Bight which have been delineated as heavy species use areas or critical habitat of endangered species or unique populations; blocks within 12 miles of the Sea Otter Game Refuge and Point Estero; the areas off Santa Cruz, San Mateo and San Francisco Counties to the 500 fathom contour; the area from Bodega Head to the northern boundary of the Central California planning area; and an additional 40 blocks in the vicinity of Cordell Bank. California Department of Conservation, Division of Oil and Gas, recommended deferral of the areas near San Diego and Orange Counties and the offshore area extending from Morro Bay to the northern boundary of Monterey Bay. California State Water Resources Control Board recommended deferral of the areas within 6 miles of Areas of Special Biological Significance.

A letter signed by 22 members of the California legislature objected to expansion of the Southern California planning area. The letter also commented (as did the California Lieutenant Governor) that the proposed subarea deferrals are insignificant deletions of areas already protected by law or established as being of no interest to industry and requested the following further deferrals: the areas within a 12-mile buffer zone from the San Diego County/Mexico boundary to Newport Beach in Orange County; the area within the access routes to the Ports of Los Angeles, Long Beach, and San Luis; the area within and immediately adjacent to Santa Monica Bay; the areas off San Mateo and Santa Cruz Counties; and the area north of the Santa Maria River. California's

Lieutenant Governor recommended deletion of the four Northern California basins, the areas near Santa Monica Bay and Orange and San Diego Counties, and the offshore area between Santa Barbara Channel and the Mexican Border. One assemblyman commented that the proposed subarea deferrals are not equitably distributed among the three California planning areas and that protection must be provided for areas which have been under moratorium in the past. California Coastal Commission expressed opposition to any leasing off the State and specifically requested deferral of the northern Santa Maria Basin and the offshore area between Santa Barbara Channel and the Mexican border.

Oregon Department of Geology and Mineral Industries commented that the proposed Washington-Oregon planning area includes areas which cannot be safely or economically drilled and that Heceta and Stonewall Banks areas should be delineated and deleted.

° Local Governments: City of Oxnard endorsed the proposed deferral of nine California OCS subareas. City of Monterey and Association of Monterey Bay Area Governments (AMBAG) endorsed the proposed deferral of the Monterey Bay and Big Sur subareas. City of Monterey also asked that these two subareas be expanded. Ventura County endorsed creation of the Central California planning area as allowing for a more precise definition of problems and issues for each of the geographic regions of California. City of Santa Barbara and Ventura County endorsed the proposed deferral of the Channel Islands Marine Sanctuary and the Santa Barbara Federal Ecological Preserve and Buffer Zone. City of Carmel-by-the-Sea endorsed the proposed deferral of the Big Sur subarea but stated that the subarea is technologically off limits to industry anyway. The City of San Luis Obispo expressed support for the reconfigured California planning areas with the exception of the present seaward boundary limits. Laguna Beach and Newport Beach expressed opposition to reconfiguring the California OCS from two to three planning areas.

AMBAG stated that a balanced leasing program would defer the Santa Cruz Basin. City of Carlsbad adopted a resolution requesting deletion of the area off San Diego County. City of Coronado requested deferral of areas included in previous Congressional moratoria, blocks which have not received bids in previous sales, blocks requested to be deleted from Sale 80 by the Defense Department, and blocks in waters deeper than 400 meters. City of Huntington Beach recommended deletion of areas adjacent to State Waters. City of Lompoc requested that leasing in Santa Monica Basin be deferred until compliance with proper air quality standards can be assured. City of Irvine requested deferral of all areas south of Point Conception. City of Laguna Beach recommended deferral of the area off Orange County extending to Catalina Island. Monterey County recommended deferral of the offshore areas north of the Santa Maria River, blocks within 6 nautical miles of Catalina Island, blocks in Santa Monica Bay and the area off Orange and San Diego Counties. They also recommended deferral of blocks within Santa Barbara Channel until cumulative impact problems are resolved and stated that the Eel River, Bodega, Point Arena, and Santa Cruz basins are biological and scenic resource areas which contain relatively small potential hydrocarbon resources. City of Newport Beach recommended deferral of local marine environmentally sensitive areas such as Newport Beach Marine Life Refuge. City of Oceanside and San Diego Association of Governments recommended deletion of blocks deleted from previous sales;

blocks which have not been bid upon by industry; blocks which the Department of Defense requested be deferred from Sale 80; blocks in waters deeper than 400 meters; nearshore blocks that would adversely impact the air quality of the San Diego region; and nearshore blocks adjacent to sensitive biological resources off the San Diego coastline, including the Santa Margarita River, Oceanside Harbor, the San Luis Rey River, and Buena Vista Lagoon. They also recommended deletion of areas previously covered by Congressional moratoria.

The City and County of San Franciso commented that reconfiguring the California OCS into three planning areas would increase opportunities for oil and gas leasing activity. They also stated that many areas proposed for deferral already are protected by law and the total acreage proposed for deferral represents just a fraction of the California OCS. Marin County and Santa Cruz County stated that the California OCS planning areas are too large.

Several local governments commented on this topic by noting the proposed reconfiguration of California OCS planning areas in resolutions stating general opposition to the Proposed Program. These include Mendocino County, Monterey County, San Luis Obispo County, San Mateo County, and Santa Cruz County. Orange County recommended deletion of the entire area off the county to Catalina Island. City of Oxnard commented that additional areas of special biological or scenic significance should be identified and deferred. City of Palos Verdes Estates expressed opposition to leasing any blocks off the Palos Verdes coast. City of Redondo Beach, City of Torrance, and City of Santa Monica recommended deletion of Santa Monica Bay. Santa Monica also recommended deletion of shipping lanes west of the bay. San Diego County recommended deletion of blocks within 3 to 27 miles of the coast. City of San Diego requested deferral of blocks offered but not bid on in previous sales off San Diego, blocks deleted from previous sales, areas covered by previous Congressional moratoria, and blocks in waters deeper than 400 meters (until proven production technology is developed for such depths). City of San Luis Obispo and San Luis Obispo County recommended deferral of a 12-mile buffer around the sea otter range and a 20-mile buffer around Morro Bay. Santa Barbara County requested that leasing in Santa Barbara Channel and Santa Maria Basin be deferred until the cumulative aspects of existing development are documented and it can be established that local infrastructure can accommodate further development. South Coast Air Quality Management District recommended deferral of leasing off Southern California pending the outcome of negotiated rulemaking concerning air quality. Ventura County recommended deferral of the Santa Barbara Channel and Santa Maria Basin until compliance with air quality standards can be assured.

° Federal Agencies: NASA noted that the offshore launch range at Vandenberg Air Force Base (AFB) California is an area of concern. DOD (Navy) stated that it will seek deferral of the Vandenberg AFB offshore launch area and endorsed the proposed deferral of the Southern California Coordinated Anti-Submarine Warfare Training Area.

° Industry: Several commenters specifically endorsed the proposed configuration of California OCS planning areas. These include: National Ocean Industries Association (NOIA), American Petroleum Institute (API), Western Oil and Gas Association (WOGA), Amoco, ARCO, BP Alaska, Chevron, Exxon, Texaco, and Unocal. Chevron commented that it would be appropriate to defer the subarea off Big Sur. Conoco expressed disappointment with the proposed deferral of the subarea off Point Reyes Wilderness, the Santa Barbara Ecological Preserve and

Buffer Zone, and the Coordinated Anti-Submarine Warfare Training Area. Murphy Oil expressed opposition to the proposed deferral of the Santa Barbara Ecological Preserve and Buffer Zone and the Channel Islands National Marine Sanctuary. Shell expressed concern over the proposed deferral of the subareas off Point Reyes Wilderness and off Big Sur and requested that specific portions of these subareas be offered for lease. API and NOIA expressed support for the proposed extension of the outer boundaries of the Northern California and Washington-Oregon planning areas. Murphy Oil commented that deferral of the California OCS subareas highlighted for further analysis would be acceptable.

° Environmental and Other Organizations: NRDC and Get Oil Out, Inc. endorsed the subarea deferrals proposed off California and stated there should be more. The League of Women Voters of Santa Barbara and League of Women Voters of Ventura County stated that subareas protected by laws, regulations, and administrative orders must be permanently deleted from leasing rather than deferred. NRDC, Friends of the Sea Otter, and Oceanic Society (San Francisco Bay Chapter) commented that subareas proposed for deferral represent a small fraction of the total size of California OCS planning areas. They also noted that several of the subareas proposed for deferral are protected to some extent by existing laws, regulations, and orders. Sierra Club (Santa Lucia Chapter) commented that the boundary between the Central California and Southern California planning areas should be located at the same latitude as the Santa Maria River. Friends of the Irvine Coast recommended deferral of the offshore area between Corona Del Mar and Laguna Beach. Friends of the Coast expressed opposition to leasing the offshore area from Morro Bay to the Oregon border. Friends of the Sea Otter requested deletion of all waters north of Santa Maria River, as well as areas in southern California previously protected by Congressional moratoria. Get Oil Out, Inc., League of Women Voters Northern California Coalition, and League of Women Voters of Sacramento recommended deferral of the offshore areas north of Santa Maria River including Eel River, Bodega, Point Arena, Santa Cruz, and northern Santa Maria Basin. Get Oil Out, Inc. also recommended deferral of blocks within 6 nautical miles of Catalina Island and blocks off Santa Monica Bay and San Diego. League of Women Voters of San Luis Obispo recommended deletion of areas where onshore topography would necessitate tankering of crude oil, areas with uneconomical reserves, areas of biological significance to fisheries as identified by the California Coastal Commission, and the area 3 to 15 miles off the coast between Point Sal and Point Arguello. League of Women Voters of Santa Barbara recommended deferral of leasing in Santa Barbara Channel and Santa Maria Basin until MMS air quality regulations are modified to require that OCS emissions be subject to the same controls as onshore emissions. League of Women Voters South Central Regional Task Force and League of Women Voters of Ventura County recommended deferral of certain blocks off Point Mugu and adjacent to the State designated Area of Special Biological Significance. League of Women Voters of Santa Cruz recommended deferral of Santa Cruz Basin. Monterey Peninsula Chamber of Commerce expressed opposition to leasing in Monterey Bay and along the coast to the San Luis Obispo County line. Newport Heights Community Association recommended deferral of Catalina Channel and nearshore blocks. Pacific Coast Federation of Fishermen's Associations recommended deferral of the areas surrounding Monterey Canyon and San Nicolas Island. Sierra Club (Santa Lucia Chapter) recommended deferral of the offshore area between Santa Maria River and Monterey Bay. Desomount Club urged deletion of the OCS area adjacent to the Orange County coastline. California Native Plant Society recommended deferral of the 70-mile strip of coastline from the Sinkyone State Wilderness Park, along the proposed King Range Wilderness Area, and up to the mouth of the Eel River. NRDC endorsed California Coastal Commission's recommendations concerning subarea deferrals.

° Private Citizens: A number of commenters stated that the proposed subarea deferrals comprise too small an area and already are protected by existing laws, regulations, and orders. Several commenters recommended deferral of one or more of the subareas described above by other commenters addressing this topic.

° Congress: Congressman Robert Badham recommended deferral of the entire Orange County coast. Under the auspices of P.L. 99-190, two congressional proposals incorporating subarea deferrals were developed--the Regula Proposal and the Panetta Proposal.

-Alaska

° State Governor: Alaska commented that efforts must continue to determine the boundary between State and Federal lands. Alaska also recommended deferral of blocks within 35 miles of Unimak Pass, 39 miles of the Pribilof Islands, 12 miles of the Yukon Delta, and traditional subsistence hunting areas in close proximity to Point Barrow.

° Local Governments: Bristol Bay Coastal Resource Area recommended establishing buffers around Unimak Pass, the Pribilof Islands, and other documented environmentally sensitive areas. North Slope Borough recommended deferral of the 59 blocks off Point Barrow which the Proposed Program highlighted for further analysis.

° Federal Agencies: The National Oceanic and Atmospheric Administration (NOAA) commented that several planning areas include vast areas of continental slope and deep ocean basin which should be delimited as separate planning areas. They suggested that there be continental shelf planning areas (less than 200m) and off-shelf planning areas (greater than 200m). St. George Basin, Beaufort Sea, Gulf of Alaska, Kodiak, and Shumagin were cited specifically for such treatment. EPA recommended deferral of all blocks within a 50-mile radius of Unimak Pass, thereby expanding the subarea defined by the MMS in the Proposed Program to include blocks in the Shumagin planning area.

° Industry: Alaska Oil and Gas Association (AOGA), BP Alaska, and Texaco specifically endorsed the proposed configuration of Alaska OCS planning areas. API and NOIA expressed support for the addition of Official Protraction Diagram NS 7-8 to the Beaufort Sea planning area. Murphy Oil expressed opposition to deferral of the 59-block area off Point Barrow, stating that the area may have some hydrocarbon potential.

° Environmental and Other Organizations: Institute for Resource Management (IRM) comments addressed all Bering Sea planning areas except the North Aleutian Basin and recommended deferral of subareas within the Norton Basin, Navarin Basin, and St. George Basin. NRDC endorsed these recommendations. Signatories of the IRM agreement, as of August 11, 1986, include representatives of: Chevron Corporation; Standard Oil Production Company; Pennzoil Exploration and Production Company; Phillips Petroleum Company; Texaco USA; Conoco, Inc.; Pogo Producing Company; Benton and Associates; Natural Resources Defense Council; Conservation Law Foundation of New England; Environmental Policy Institute;

Friends of the Earth; Trustees for Alaska; Sierra Club; Coast Alliance; The Wilderness Society; Northern Alaska Environmental Center; Alaska Center for the Environment; Bering Sea Fishermen's Association; United Fishermen of Alaska; Cenaliuriit Coastal Management District; Nunam Kitlutsisti; Village of Alakanuk; Village of Chefornak; Village of Chevak; Village of Emmonak; Village of Hooper Bay; Village of Kotlik; Village of Newtok; Village of Nightmule; Village of Scammon Bay; Village of Sheldon's Point; Village of Toksook Bay; Village of Tunvak; and Bristol Bay Coastal Resource Service Area.

A.2. Leasing Schedule Options for the Proposed Final Program

Basic Leasing Schedule Options

OPTION A.2.a Adopt the Proposed Final Program base schedule of standard sales, updated to cover mid-1987 through mid-1992. (This option is subject to modification by the selection of suboptions b, c, d, e, f, g, or h, below.)

OPTION A.2.b Add a single sale in the Straits of Florida in 1992 (south of 25°07' N. latitude).

OPTION A.2.c Defer leasing in any or all of the following six planning areas:

- i. North Atlantic
- ii. Southern California
- iii. Central California
- iv. Northern California
- v. Washington-Oregon
- vi. North Aleutian Basin
- vii. All six areas

OPTION A.2.d Schedule biennial sales in any or all of eight areas with higher value and/or higher interest:

- i. Southern California
- ii. Central California
- iii. Northern California
- iv. Eastern Gulf of Mexico
- v. Beaufort Sea
- vi. Navarin Basin
- vii. North Aleutian Basin
- viii. St. George Basin
- ix. All eight areas

Discussion of Basic Schedule Options

-Section 18 Considerations

The location and timing of lease sales which comprise a 5-year OCS leasing program must be based on consideration of the factors specified in section 18(a)(2) and the balancing requirement of section 18(a)(3). The text of those sections appears in Part I, above. Part II and the supporting appendices provide the required analysis.

For those factors that were quantified, the resulting net social value estimates are shown in Table 12.1. As Table 12.1 shows, the social costs of OCS oil and gas activity make the net social value in each area somewhat lower than the net economic value, but do not change the ranking of the various areas by net economic value. These estimates, plus other quantitative and qualitative information and the economic guidelines set forth in Appendix F, provide a starting point for determining the location and timing of lease sales in each area (see Part II.D, above).

Other considerations are also relevant to the scheduling of sales:

-Judgments about the degree of precision of and weight which should be attributed to estimates of relative net social value, based on such factors as:

-- The sensitivity of net economic value estimates to changes in assumptions which correspond to the possibility of changes in the world oil market, including those that could result from an oil supply disruption. This consideration relates to the net social value quantitative balancing of costs and benefits pursuant to section 18(a)(3). The variation in starting oil prices (from $14 to $29 per barrel) and further oil price sensitivity cases assuming starting prices of $9 and $34 per barrel result in an oil price range depicted in Figure 1. Table 12.1 reflects only the basic $14 - $29 variation in starting oil prices. Tables 9 and 13 in Appendix F reflect the variation of the real oil price growth rates (0 to 2 percent) and variation in discount rates (6 percent and 8 percent).

-- An evaluation of the available geological and geophysical data on which the resource estimates are based (see Appendix E). This consideration relates to section 18(a)(2)(A) both in itself and insofar as it constitutes part of the data base for the net social value quantitative balancing of costs and benefits pursuant to section 18(a)(3).

-The results of leasing and exploration in an area (see Appendix H). Those results are the source of the information which the Secretary is required to consider under section 18(a)(2)(A) and a necessary consideration for making a decision on a leasing program under section 18(a);

-The relative marine productivity/environmental sensitivity analysis considered in itself, in addition to its use as an input to the social cost analysis (see Part II.B.3 and Appendix I). This consideration is required by section 18(a)(2)(G).

-The desirability of acquiring new geological and geophysical data through exploratory work, including the drilling attendant on leasing. This consideration is specified as one of the purposes of the OCS Lands Act Amendments, which also added section 18 (see OCS Lands Act Amendments section 102(9)). This consideration is also a crucial element in complying with the section 18(a) standard that the program meet national energy needs.

-The desirability of follow-up sales in areas with scheduled sales and/or existing leases. This consideration is based on the provision of section 18(a) that the leasing program be one which the Secretary determines will best meet national energy needs.

-The avoidance of drainage of unleased blocks. This consideration is based on the requirement of section 18(a)(4) that DOI obtain fair market value for lands leased and rights conveyed.

-The time necessary to acquire useful data from blocks leased in the preceding sale in an area. This consideration is related to the requirement that the leasing program meet national energy needs and the requirement of section 18(a)(4) that DOI obtain fair market value for lands leased and rights conveyed. In areas where there is an ongoing exploration effort, new exploratory information and ideas are generated at a faster pace and leasing at a faster pace can be appropriate.

-The time necessary to acquire environmental studies data for use in the sale decision process, pursuant to section 20 of the OCS Lands Act.

-Administrative considerations, including the cost of offering an area in a sale. If an area is being offered for the first time or after a long hiatus in leasing, the cost of holding a sale, including environmental studies, would be higher than in the case where funds have already been expended for studies and other presale analysis. The marginal cost of holding an additional sale in an area is estimated to be approximately $1 million. This consideration reflects the section 18(b) requirement that the Secretary include in the leasing program estimates of appropriations and staff for carrying it out. Section 18(b) makes clear the congressional view of the relevance of administrative resources and limitations to the formulation of a leasing program under section 18(a). Estimates of appropriations and staff appear below in this Part and in Appendix T.

-Comments in response to Federal Register notices including comments of States and industry rankings of areas by resource potential and by exploration interest (see Tables 13.1, 13.2, and 13.3 on the following pages and Appendices B and D). Public comments are called for by sections 18(c) and (d). Industry interest is specifically mentioned in section 18(a)(2)(E).

-Scheduling Sales in Group I Net Social Value Areas

As can be seen from Table 12.1, the Central and Western Gulf of Mexico areas are clearly those with the highest net social value. Each of them has over four times the potential net social value of the next best areas over the range of price assumptions. Industry has also ranked these two areas most highly. The ongoing exploration effort in these areas also provides a continuous stream of new geologic and geophysical information which can serve as the basis for frequent sales there.

Drainage and field development considerations also figure strongly in the timing of lease sales in the Central and Western Gulf of Mexico. The MMS estimates that because of the level of activity in the Central and Western Gulf of Mexico, there could be about 75-100 unleased blocks susceptible to drainage of hydrocarbons in each of those two areas each year. Failure to lease these blocks once drainage begins reduces Federal revenues and could provide unwarranted profits to adjacent leaseholders. Failure to offer development blocks subsequent to nearby discoveries can lead to production delays or less than optimal field development. These two planning areas have by far the greatest cost of delay of leasing, considering the per-barrel cost of delay in Table 6 and the resource potential in Table 2. Thus, it is appropriate to hold sales as often as annually in the Central and Western Gulf of Mexico, continuing the same timing in those areas as in the 1982 5-year leasing program.

Table 13.1



Industry Interest in OCS Planning Areas Based on the July 1984 Request /1
(Not all companies ranked all areas)

| Overall Ranking /2 | | Range of Companies' Rankings /3 |
|---|---|---|
| 1 | Central Gulf of Mexico | 1 to 5 |
| 2 | Western Gulf of Mexico | 1 to 7 |
| 3 | Beaufort Sea | 1 to 7 |
| 4 | (tie) Southern California | 1 to 11 |
| 4 | (tie) Central & Northern California | 3 to 14 |
| 6 | Eastern Gulf of Mexico | 3 to 12 |
| 7 | Navarin Basin | 2 to 11 |
| 8 | North Aleutian Basin | 3 to 14 |
| 9 | St. George Basin | 3 to 15 |
| 10 | Chukchi Sea | 2 to 13 |
| 11 | North Atlantic | 7 to 22 |
| 12 | Norton Basin | 8 to 18 |
| 13 | Washington-Oregon | 5 to 21 |
| 14 | Mid-Atlantic | 9 to 23 |
| 15 | Hope Basin | 10 to 19 |
| 16 | Cook Inlet | 9 to 20 |
| 17 | Shumagin | 12 to 22 |
| 18 | South Atlantic | 10 to 24 |
| 19 | Gulf of Alaska | 12 to 21 |
| 20 | St. Matthew-Hall | 14 to 23 |
| 21 | Kodiak | 13 to 24 |
| 22 | Bowers Basin | 16 to 24 |
| 23 | (tie) Aleutian Arc | 12 to 24 |
| 23 | (tie) Aleutian Basin | 15 to 23 |

/1 This table is included for historic purposes. See cautionary note in the last two paragraphs of p. D-11.

/2 Rank order of mean (average) ranks of companies ranking the OCS planning area on the basis of interest in exploration and development.

/3 Reflects highest and lowest ranking by companies ranking the particular OCS planning area on the basis of interest in exploration and development.

Table 13.2

Industry Interest in OCS Planning Areas Based on the March 1985 Request /1
(Not all companies ranked all areas)

| Overall Ranking /2 | | Range of Companies' Rankings /3 |
|---|---|---|
| 1 | Central Gulf of Mexico | 1 to 2 |
| 2 | Western Gulf of Mexico | 2 to 5 |
| 3 | Beaufort Sea | 1 to 6 |
| 4 | Southern California | 1 to 8 |
| 5 | Eastern Gulf of Mexico | 3 to 10 |
| 6 | North Aleutian Basin | 3 to 9 |
| 7 | Central California | 4 to 11 |
| 8 | Navarin Basin | 4 to 10 |
| 9 | Northern California | 4 to 11 |
| 10 | Chukchi Sea | 4 to 20 |
| 11 | St. George Basin | 8 to 17 |
| 12 | Norton Basin | 9 to 18 |
| 13 | Hope Basin | 9 to 19 |
| 14 | North Atlantic | 12 to 17 |
| 15 | Mid-Atlantic | 11 to 21 |
| 16 | Cook Inlet | 10 to 21 |
| 17 | South Atlantic | 12 to 22 |
| 18 | Washington-Oregon | 11 to 22 |
| 19 | Straits of Florida | 14 to 24 |
| 20 | Gulf of Alaska | 15 to 22 |
| 21 | Shumagin | 14 to 25 |
| 22 | Kodiak | 18 to 25 |
| 23 | St. Matthew-Hall /4 | 16 to 26 |
| 24 | Aleutian Basin /4 | 14 to 25 |
| 25 | Bowers Basin /4 | 21 to 26 |
| 26 | Aleutian Arc /4 | 20 to 26 |

/1 This table is included for historic purposes. See cautionary note in the last two paragraphs of p. D-11.

/2 Rank order of mean (average) ranks of companies ranking the OCS planning area on the basis of interest in exploration and development.

/3 Reflects highest and lowest ranking by companies ranking the particular OCS planning area on the basis of interest in exploration and development.

/4 These four areas were deleted from the Draft Proposed 5-Year Program.

Table 13.3

Industry Interest in OCS Planning Areas Based on the February 1986 Request
(Not all companies ranked all areas)

| Overall Rank /1 | Range of Companies' Rankings /2 |
|---|---|
| 1. Central Gulf of Mexico | 1-2 |
| 2. Western Gulf of Mexico | 2-4 |
| 3. Eastern Gulf of Mexico | 3-8 |
| 4. Beaufort Sea | 1-14 |
| 5. Southern California | 1-12 |
| 6. Central California | 2-15 |
| 7. North Aleutian Basin | 5-9 |
| 8. Northern California | 2-13 |
| 9. Chukchi Sea | 4-16 |
| 10. Navarin Basin | 7-15 |
| 11. North Atlantic | 6-17 |
| 12. St. George Basin | 6-18 |
| 13. Mid-Atlantic | 7-22 |
| 14. Hope Basin | 8-21 |
| 15. Washington-Oregon | 7-22 |
| 16. Cook Inlet | 8-22 |
| 17. South Atlantic | 8-22 |
| 18. Norton Basin | 9-20 |
| 19. Gulf of Alaska | 12-22 |
| 20. Straits of Florida | 14-26 |
| 21. Shumagin | 14-25 |
| 22. St. Matthew-Hall /3 | 16-26 |
| 23. Kodiak | 17-25 |
| 24. Aleutian Basin /3 | 14-25 |
| 25. Bowers Basin /3 | 21-26 |
| 26. Aleutian Arc /3 | 21-26 |

/1 Rank order of mean (average) ranks of companies ranking the OCS planning area on the basis of interest in exploration and development.

/2 Reflects highest and lowest ranking by companies ranking the particular OCS planning area on the basis of interest in exploration and development.

/3 These four areas were deferred at the Draft Proposed 5-Year Program stage.

-Scheduling Sales in Group II and III Net Social Value Areas

Group II areas are those where leasing is projected to have a positive net social value across the basic range of starting oil price assumptions ($14 to $29/bbl.): Southern California; South Atlantic; Mid-Atlantic; Eastern Gulf of Mexico; Central California; Northern California; North Atlantic; and Washington-Oregon. Group III areas are those with a positive net social value at the high end of that range, but with a negligible net social value figure in the lower oil price case(s): Navarin Basin; Chukchi Sea; Beaufort Sea; St. George Basin; Gulf of Alaska; North Aleutian Basin; Norton Basin; and Straits of Florida.

Put another way, Group II areas are those where OCS lease sales could be expected to attract bidders even at lower levels of oil price expectations. Sales in these areas could be scheduled with greater confidence that there will be bidding interest and that a net gain in social value will be realized as a result of leasing there. Less confidence in a comparable result is appropriate for Group III areas, where a lower level of oil price expectations could substantially reduce its attractiveness to potential bidders. Given the volatility of oil prices and the limits on predicting them, it may still be reasonable to schedule sales in Group III. The 5-year program schedule has great flexibility in terms of the Secretary's ability to cancel or delay sales, but it has great inflexibility in that sales can be added to the schedule only through a repetition of the process by which the schedule was originally approved.

The net social value figures can also be used to consider distinctions among areas, such as the following. The Eastern Gulf of Mexico has more resource potential in the high value category than Navarin Basin and at least twice the per barrel cost of delay in all oil price cases (see Appendix F, Tables 7 and 9). This would suggest that, in general, leasing in the Eastern Gulf of Mexico should have priority over leasing in the Navarin Basin. However, the substantial gain in resource potential in higher oil price cases in the Navarin Basin area contributes to making it reasonable to schedule lease sales there more frequently than in other areas which do not show such substantial gains (see Appendix F, Table 8).

In interpreting MMS net social value estimates for the purpose of formulating a 5-year leasing program, it should be noted that section 18(a)(2)(E) specifically requires consideration of the interest of potential producers of oil and gas. Of particular significance are those cases in which industry ranks an area differently from MMS (see Table 13.4 and Appendices B, D, and F). For example, industry ranked the Beaufort Sea in the top four of all areas, whereas MMS resource estimates show Beaufort Sea (not counting estimated gas resources) in the middle rank of all areas. This strengthens the case for triennial or even biennial sales in the Beaufort Sea, although other considerations also figure into this question. Another example concerns the South Atlantic, which MMS ranked high whereas industry ranked it low. It is on this basis that the South Atlantic planning area is not included in the biennial sales option.

There are a number of factors which can cause industry interest rankings to differ from MMS net social value rankings. The MMS net social value ranking is computed from the risked mean resource estimate. Industry commenters may have different estimates of risk or may weigh conditional (unrisked) estimates more highly. Industry interest rankings may also include considerations not reflected in MMS resource estimates, such as ease of operations. Finally, some companies may reflect in their rankings perceptions of potential legal and regulatory hurdles which are not accounted for in net social value rankings.

Table 13.4

Comparison of Spring 1986 Industry Interest and Net Social Value Rankings for the Proposed Final Program

| Planning Area | Industry Interest (Spring 1986) | Net Social Value* |
|---|---|---|
| Central Gulf of Mexico | 1 | 1 |
| Western Gulf of Mexico | 2 | 2 |
| Eastern Gulf of Mexico | 3 | 6 |
| Beaufort Sea | 4 | 12 |
| Southern California | 5 | 3 |
| Central California | 6 | 8 |
| North Aleutian Basin | 7 | 17 |
| Northern California | 8 | 5 |
| Chukchi Sea | 9 | 15 |
| Navarin Basin | 10 | 7 |
| North Atlantic | 11 | 13 |
| St. George Basin | 12 | 10 |
| Mid-Atlantic | 13 | 9 |
| Hope Basin | 14 | 20 |
| Washington-Oregon | 15 | 11 |
| Cook Inlet | 16 | 22 |
| South Atlantic | 17 | 4 |
| Norton Basin | 18 | 18 |
| Gulf of Alaska | 19 | 16 |
| Straits of Florida | 20 | 14 |
| Shumagin | 21 | 21 |
| Kodiak | 23** | 19 |

* See Table 12.1
** Kodiak ranked below #22, St. Matthew-Hall (see Table 13.3).

Especially in the case of areas that have not yet been offered for lease, the MMS resource estimating process is limited by the availability of drilling data. More data could lead to a significant revision of resource estimates.

Five areas have never had a complete lease sale actually held: North Aleutian Basin; Chukchi Sea; Hope Basin; Shumagin; and Kodiak. Four other areas have not had a lease sale for 20 or more years: the new Central and Northern California planning areas; Washington-Oregon; and the Straits of Florida.

Considerable discretion within section 18 requirements is appropriate in scheduling sales in these areas. It would be reasonable to schedule sales in various Group II and Group III areas in a variety of ways, including biennially or triennially, based on a consideration of net social value figures, oil price expectations, industry interest, and other section 18 factors. Further distinctions with respect to scheduling sales in Group II and III areas could be made by means of the frontier exploration sale request for interest process.

It is also worth recalling that the option in question deals with scheduling sales in a planning area. The net social value figures are planning area estimates and do not reflect the geographic distribution of prospects within a planning area. It is during the presale process that that question is usually addressed. During the presale process, the balancing of resource, environmental, and multiple-use considerations is performed. For example, in the presale process for Sale 92, North Aleutian Basin, a relatively small part of the planning area was rated as highly prospective by industry. The presale process for Sale 92 reduced the size of that sale to about 17 percent of the planning area. The discussion of subareas, above, also bears on this issue.

-Scheduling Sales in Group IV Net Social Value Areas

These planning areas (Kodiak, Hope Basin, Shumagin, and Cook Inlet) include areas estimated to have negligible leasable resources and thus negligible net economic value throughout the range of oil price cases. All of the areas in this group, however, are estimated to have resources which are developable (i.e., profitable to develop once found) but not leasable (i.e., not profitable for a firm to bid on, given risk and exploration costs) (see Table 4).

The balancing of benefits and costs for areas estimated to have no leasable resources must proceed on a per-barrel basis rather than on total planning area estimates. The comparison can proceed by making the assumption--not made by the net economic value analysis whose results are displayed in Tables 1, 2, and 12.1 in the SID--that if some or all of the developable resources in these areas were leased, their expected private value (the after-tax net present value for the bidder--see Appendix F) would have to be equal to or greater than zero. Assuming--on the low side--that private value is equal to zero for each of those planning areas, it is possible to compute the estimates of net economic value per barrel for those areas (see Table 12.2, above). In all of these areas, the net economic value projection exceeds the social cost projection. As indicated in Part II.B and Appendix F, one consideration involves the possible increases in leasable resource potential and net economic value that could result from increases in oil prices, new geologic and geophysical data, or other factors affecting costs and risk. One such factor which could change the attractiveness of low-valued Alaska areas would be the lifting of the legal limitation on the export of oil to Japan in section 28 of the OCS Lands Act. The reduced costs of transporting certain Alaskan oil to Japan could cause the net social value of Alaska OCS oil and gas to rise.

An evaluation of the available geophysical and geological data on which MMS resource estimates are based appears in Table 12.1 and Appendix E. The limitations of the available data as well as the specific mandate of section 18(a)(2)(E) call for consideration of the judgment of potential oil and gas producers as expressed in comments and nominations as well as exploration as an important source of additional information (see Tables 13.1, 13.2, and 13.3 and Appendices B, D, E, and H). This is particularly so since potential bidders are under no constraints to submit bids. The scheduling of lease sales, therefore, must give considerable weight to expressions of industry interest in order to avoid wasting the planning resources of all parties.

-Providing Incentive for the Collection of More Geological and Geophysical Data

In addition to MMS and industry rankings, another consideration with respect to scheduling a sale in an area is that it could create or sustain an incentive for firms to collect additional data. Section 102(9) of the OCS Lands Act Amendments of 1978 provides a mandate for the early assessment of the oil and gas resources of the OCS. That consideration is a salient one for areas where there is a paucity of geological and geophysical data (see Appendix E). If additional data resulted in changes in current interpretations of the hydrocarbon potential of low value area, leasing there could be pursued; if not, leasing there could be deferred. In any event, uncertainty concerning an area's resource potential would be reduced.

-Effects of Deferring Leasing in a Planning Area

It should be noted that the deferral of an area from inclusion in the leasing program means that, barring a significant revision of the new program, it will not be offered for lease through mid-1992. As a result, the incentive to gather new geological and geophysical data on such an area could be reduced, so that the data available for deciding whether to include that area in the formulation of future programs could be no better than at present.

In addition, foregoing potential oil and gas development by not scheduling a lease sale is not without potential social costs for an area. If increased oil imports via foreign tankers result, potential social costs could well be incurred from oil spills associated with such tankering. Such costs would be incurred in addition to the opportunity cost of the value of production foregone or deferred. These costs are included in those calculated for the various program alternatives (see below).

-Sale Schedules

It is important to stress that the deferral of leasing in any planning area in the program for 1987 through 1992 in no way affects any United States claims to jurisdiction and control over submerged lands under the OCS Lands Act or the EEZ Proclamation of 1983. Changes in MMS's resource estimates, economic conditions, and/or industry interest may lead, under future 5-year programs, to the offering of blocks located in any planning area not included in the 5-year program for 1987 through 1992. All maps of the new program will continue to show all OCS planning areas, whether leasing is scheduled there in the new program or not.

The schedule options presented here specify only the year in which a sale would be held. A description of presale steps is set forth in Appendix L. It should be noted that the number of sales in an area in the new program is not an independent element. Rather, a "triennial" sale, as such, is scheduled for the third calendar year after the last scheduled sale in the area. Because of administrative considerations--for example, balancing workload at the MMS regional and headquarters offices--the interval between triennial sales may be somewhat more or less than 36 months. A schedule showing the option selected and presale steps by month will be issued as part of the public announcement of the Proposed Final Program.

The scheduling of California sales in all options is consistent with the requirements of P.L. 99-591.

Location and Timing Comments

-General

° State Governors: New Hampshire commented that the location of proposed sales is appropriate. Re: timing, New Hampshire, New Jersey, Rhode Island and Virginia endorsed the overall pace of leasing proposed. Alabama commented that the pace of leasing in planning areas other than Central and Western Gulf of Mexico is insufficient. Louisiana and Texas commented that slowing the pace of leasing in all planning areas other than Central and Western Gulf of Mexico results in an unbalanced program.

° Federal Agencies: EPA commented that an environmentally preferable proposal for leasing would combine deferral of 28 subareas and deferral of leasing in any or all of the following six planning areas: North Atlantic, Southern California, Central California, Northern California, Washington-Oregon, and North Aleutian Basin. Re: timing, EPA endorsed the proposed scheduling of annual sales in the Central and Western Gulf of Mexico planning areas and triennial sales elsewhere. DOD endorsed the proposed pace of leasing for allowing a more deliberate process and additional time for conflict resolution. DOE stated that they are pleased that the pace of the Proposed Program is similar to that announced in the Draft Proposed Program (March 1985).

° Industry: ARCO, BP Alaska, Chevron, Conoco, Mobil, Murphy Oil, Shell, and WOGA endorsed the location of proposed sales. Re: timing, Several commenters stressed the importance of reliability and predictability in the leasing schedule. BP Alaska stated that the total number of sales on the proposed schedule is acceptable. Chevron, Unocal, and Standard expressed agreement with the overall proposed schedule. Standard also noted that the acceleration provision is expected to step up the pace of leasing in frontier areas of encouragement. Murphy Oil and ARCO commented that the proposed pace of leasing would be acceptable if flexibility provisions are instituted and prove effective. Amoco, Mobil, Tenneco, and Texaco commented that triennial leasing is not compatible with regulations requiring public release of well information 2 years after its date of submission. Amoco, ODECO, Phillips, Zapata, API, NOIA, WOGA, and Offshore Operators Committee (OOC) expressed support for biennial leasing in planning areas other than Central and Western Gulf of Mexico. Amoco stated that biennial leasing would be appropriate in all planning areas except those in the Atlantic. Conoco stated that triennial sales would be preferable in most frontier areas. Tenneco expressed opposition to triennial leasing and support for a biennial pace. Dixilyn-Field and Pogo expressed concern about the overall slower pace of leasing proposed.

° Environmental and Other Organizations: NRDC commented that given existing low oil prices, several locations proposed for leasing are not economically viable and should not be offered. Whale Center stated that the pace of the proposed schedule is too fast. NRDC commented that the proposed schedule is based on flawed economic assumptions (e.g., those concerning oil prices and discount rate) and an inadequate sampling of industry interest.

° Private Citizens: Several commenters stated that too many sales are proposed and the interval between them is too short.

-Abbreviated Summary of Selected Additional Location and Timing Comments*

| Commenters re: Atlantic Areas | Comments |
|---|---|
| 1. EPA | 1. Supports deferring the North Atlantic planning area from leasing |
| 2. Murphy Oil USA | 2. Supports leasing in the entire Straits of Florida area (excluding a 15-mile coastal buffer) |
| 3. Amoco, Conoco, Mobil, Phillips Shell, and Standard | 3. Support scheduling a sale in the Straits of Florida planning area south of 25° 7' N latitude in 1991 |
| 4. EPA, Governor of FL, Sarasota Co. (FL), South FL Regional Planning Council, Sierra Club (FL Chapter), Florida PIRG, Greenpeace, NRDC, Senator Lawton Chiles, Congressmen William Lehman and Dante B. Fascell | 4. Support deferring the Straits of Florida planning area from leasing |
| 5. Governors of ME, RI, NJ, DE, NC, Volusia Co. (FL), Florida PIRG | 5. Support triennial pace |
| 6. MA League of Women Voters (LWV) | 6. Supports slower than triennial pace |
| 7. Friends of Canaveral (FL), Sierra Club (FL), National Audubon Society (FL), Senator Lawton Chiles | 7. Recommend completion of studies before leasing in the South Atlantic |

* A full summary of comments appears in Appendix B.

| Commenters re: Gulf of Mexico Areas | Comments |
| --- | --- |
| 1. Governor of FL, Sarasota Co. (FL), S.W. Florida Regional Planning Council, Exxon, Mobil, Florida PIRG | 1. Support triennial leasing in Eastern GOM |
| 2. Offshore Operators Committee (OOC), Shell, Standard, Murphy, Anadarko, Conoco | 2. Support biennial pace of leasing in Eastern GOM |
| 3. Sierra Club (FL), National Audubon Society (FL), Senator Lawton Chiles | 3. Recommend completion of studies before leasing in Eastern GOM |
| 4. Governor of LA | 4. Expresses concern over long-term economic and environmental impacts of annual leasing in Central and Western GOM |
| 5. OOC, NOIA, WOGA, Chevron, Conoco, Exxon, ODECO, Phillips, Pogo, Shell, Texaco | 5. Support annual leasing in Central and Western GOM |

| Commenters re: Pacific Areas | Comments |
| --- | --- |
| 1. Earth First! (Santa Cruz) | 1. Supports deferring all Pacific planning areas from leasing |
| 2. CA Coastal Commission | 2. Supports deferring all California OCS planning areas from leasing |
| 3. CA Department of Justice, Marin Co. (CA), Mendocino Co. (CA), Monterey Co. (CA), Orange Co. (CA), San Luis Obispo Co. (CA), San Mateo Co. (CA), Santa Cruz Co. (CA), Friends of the Coast, Friends of the Sea Otter, LWV of Sonoma Co. (CA) | 3. Support deferring the Central California planning area from leasing |
| 4. Environmental Allergies Organization, Pacific Coast Federation of Fishermen's Associations, Wildlife Society (Humbolt, CA Chapter) | 4. Support deferring the Northern California planning area from leasing |

| | |
|---|---|
| 5. Governor of CA, Ventura Co. (CA) | 5. Support triennial pace (but concerned about total number of sales proposed off California) |
| 6. CA Coastal Commission, CA Dept. of Justice, San Francisco (CA), Huntington Beach (CA), Orange Co. (CA), Coronado (CA), Oceanside (CA), SANDAG (CA), Carmel by the Sea (CA), Newport Beach (CA), Monterey (CA), San Luis Obispo Co. (CA), San Francisco Co. (CA), Orange Co. (CA), San Mateo Co. (CA), Santa Cruz Co. (CA), Get Oil Out, Inc., Sierra Club (Santa Lucia, (CA)), Friends of the Sea Otter, LWV's of Santa Cruz, Ventura and Berkeley (CA) | 6. Support slower than triennial pace and fewer sales |
| 7. Governor of CA; CA Department of Justice, Huntington Beach (CA), Coronado (CA), San Luis Obispo (CA) Earth First! (Santa Cruz, CA), Wildlife Society (Humboldt, CA Chapter), LWV of Santa Barbara (CA), LWV Northern California Coalition | 7. Recommend postponing action on Sales 91 and 95 until final approval of the 5-year program |
| 8. NOIA, OOC, BP Alaska, Shell, Exxon, Combustion Engineering, Conoco, Chevron, Standard | 8. Support faster than triennial pace |
| 9. Friends of the Earth (NW Office), Washington Trollers Association | 9. Support deferring the Washington-Oregon planning area from leasing |

| Commenters re: Alaska Areas | Comments |
|---|---|
| 1. EPA, Governor of AK, Bristol Bay (AK) Coastal Resource Service Area, NRDC | 1. Support deferring the North Aleutian Basin planning area from leasing |
| 2. North Slope Borough (AK) | 2. Supports deferring the Beaufort Sea and Chukchi Sea planning areas from leasing. |

3. NOAA, BP Alaska, Exxon — 3. Support triennial pace

4. Governor of AK — 4. Expresses concern about total number of sales proposed off Alaska, recommends dropping Sales 127, Kodiak, and 129, Shumagin, from the schedule, and opposes leasing in the North Aleutian Basin planning area until 1994

5. Conoco, Shell — 5. Support faster than triennial pace

6. North Slope Borough (AK) — 6. Recommends completion of studies before leasing and recommends postponing Sales 97, Beaufort Sea, and 109, Chukchi

-Basic Schedule Options

The following schedule options are based on the considerations discussed above. Options proposing leasing in a number of planning areas are analyzed in the section on valuation of program alternatives, below in this SID, and in the EIS.

OPTION A.2.a - The Base Schedule of Standard Sales

The revised base schedule (see Table 14) adjusts the comparable option selected for the Proposed Program for the new timeframe mid-1987 through mid-1992 and extends the triennial frequency selected for the new program to the added half-year. The revised base schedule contains 27 standard sales over 5 years in 13 planning areas. It schedules annual sales in the two areas in the Group I net social value group (the Central and Western Gulf of Mexico) and triennial ~~sales in 11 other areas in Groups II and III (see Part II.D).~~ Other triennial sales originally proposed as part of the base schedule option for the Proposed Program decision were designated as frontier exploration sales and are discussed below in that category. Scheduling a sale in the Straits of Florida is discussed in Option A.2.b.

The triennial pace of leasing is designed to help meet national energy needs while reducing the review burden of affected parties and the level of conflict over OCS lease sales. As indicated in the comment summary above and in Appendix B, this change from the basic biennial pace of leasing in the 1982 program has been endorsed by most commenters other than industry. One concern expressed by industry relates to the regulatory 2-year limit on the protection of proprietary data. Extension of that period of protection for proprietary data would require a change in Interior's regulations.

OPTION A.2.b - Schedule a Sale in the Straits of Florida

The Straits of Florida had been described as a separate planning area in the October 26, 1978, request for comments on development of the first 5-year program following the 1978 Amendments to the OCSLA (43 FR 50057). No sales were scheduled in that area in either the 1980 or the 1982 program. As part of the decision on the Draft Proposed Program, the area south of 28°17'10" N. latitude

Table 14

Current Leasing Schedule Overlap with Update of Standard and Frontier Exploration Sales in the Proposed Program

| | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | Mid-1992 | No. of Sales |
|---|---|---|---|---|---|---|---|---|---|---|---|
| ATLANTIC ******** | | | | | | | | | | | 4 |
| North | | 82 | | | | 96 | | | 134+ | | |
| Mid- | 76 | | | [111] | | | 121+ | | | | |
| South | 78 | | | [90] | | | | 108+ | | | |
| GULF OF MEXICO ******** | | | | | | | | | | | 12 |
| Western | 74 | 84 | 102 | 105 | 112 | 115 | 122 | 125 | 135 | | |
| Central | 72 | 81 | 98 | 104 | 110 | 113 | 118 | 123 | 131 | S | |
| Eastern | 69(II) | 79 | 94 | | | 116 | | | 137 | | |
| PACIFIC ******** | | | | | | | | | | | 6 |
| Southern CA | | 80 | | | | | 95 | | | 138 | |
| Central CA | 73 | | | | | | 119 | | | | |
| Northern CA | | | | | | | 91 | | | 128 | |
| Washington-Oregon | | | | | | | | | 132+ | | |
| ALASKA ******** | | | | | | | | | | | 14 |
| Beaufort Sea | | 87 | | | | 97 | | | 124 | | |
| Chukchi Sea | | | | | | 109 | | | 126 | | |
| Norton Basin | 57 | | | [100] | | | 120 | | | | |
| Navarin Basin | | 83 | | | | 107 | | | 130 | | |
| St. George Basin | 70 | | | [89] | | | 101 | | | | |
| N. Aleutian Basin | | | | | 92 | | | 117 | | | |
| Shumagin | | | | | | [86] | | | | 129+ | |
| Kodiak | | | | | | | | | | 127+ | |
| Cook Inlet | | | | | | | | | 136+ | | |
| Gulf of Alaska | | | | [88] | | | | | 114+ | | |
| Hope Basin | | | | | | | | | | 133+ | |
| | | | | | | | | | | Total | 36 |

Sales to the left of the vertical line include the current 5-year leasing schedule.
Sales to the right of the vertical line are part of this option for the Proposed Final Program.
S = Sale not yet numbered. Sale numbers are those in the Proposed Program.
+ = Frontier Exploration Sale.
[] = Sale cancelled

was made the new Straits of Florida planning area. The creation of this new planning area responded to comments from Florida by concentrating section 18 analyses on that area. As indicated in the summary of comments above and Appendix B, this sale is opposed by the Governor of Florida and a variety of other parties; although a number of companies favor it. Industry overall ranked the Straits of Florida as 20th out of 26 planning areas in response to the February 1986 request for comments on the Proposed Program.

As part of the decision on the Proposed Program, leasing would be deferred in the Atlantic coast portion of the Straits of Florida planning area (north of 25° 07' N. latitude). The net social value for leasing in the remaining portion of the Straits of Florida is estimated to range from negligible to $55 million ($1987).

Option A.2.b would add a single sale in the Straits of Florida in 1992, so that the necessary environmental studies could be performed if this option were chosen.

A decision not to schedule a sale in the Straits of Florida area is comparable to the deferral of leasing as discussed just below concerning Option A.2.c.

OPTION A.2.c - Deferral of Leasing in Any or All of Six Planning Areas

Option A.2.c would defer from leasing up to six whole planning areas scheduled for leasing in the Proposed Program which were requested for deferral by various comments on the Draft Proposed Program and the Proposed Program: North Atlantic; Southern California; Central California; Northern California; Washington-Oregon; and North Aleutian Basin. This option provides for an exception to the scheduling formula for the base schedule on the basis of comments submitted as provided by subsections 18(c), 18(d), and 18(f)(1) [see the summary of comments above and in Appendix B].

Some of the decision considerations applicable to this option discussed with respect to subarea deferrals above also apply to the deferral of whole planning areas. For example, on one hand, removing high conflict areas at the earliest stage of the leasing process could reduce controversy and litigation over them. In addition, deferrals of portions of planning areas could reduce the analysis burden in the presale process for all parties.

On the other hand, deferrals may be premature and may limit flexibility if made before the availability of the geological, geophysical, and environmental information usually gathered during the presale process for a sale. In addition, deferrals made at the 5-year program stage cannot be reconsidered for leasing for 5 years (unless a new 5-year program is developed--a multi-year process). This could have a dampening effect on information-gathering concerning areas which are deferred. Thus, deferrals may, effectively, become permanent. The benefits foregone by this option can be seen by reviewing the cost of delay of leasing (Table 6 in conjunction with Table 2) and the valuation of program alternatives, below.

OPTION A.2.d - Biennial Sales

Option A.2.d provides for scheduling biennial sales in up to eight planning areas. This option schedules up to 32 sales in the same planning areas included in Option A.2.a. It differs from Option A.2.a by amending it to schedule biennial sales in up to eight areas with higher value and/or higher interest: Southern California; Eastern Gulf of Mexico; Central California; Northern California; Navarin Basin; Beaufort Sea; North Aleutian Basin; and St. George Basin.

Generally, these areas are relatively highly ranked by MMS in terms of net social value (see Table 12.1) and/or by industry (see Tables 13.1, 13.2, and 13.3). Indeed, these eight areas include those ranked highest--after the Central and Western Gulf of Mexico--in industry interest as expressed in Summer 1984 and confirmed in Spring 1985 and Spring 1986. Two exceptions, however, are worthy of note. First, the Chukchi Sea has been omitted from this option--even though it was ranked ninth in the Spring 1986 industry ranking--because Sale 109 is the first sale to be held in this area. In such a case, a triennial schedule is more appropriate than a biennial one for this new program, so that the results of the exploratory drilling efforts following the first sale can be considered in preparing for the second sale. Second, St. George Basin has been retained in this option for the sake of consistency with the Proposed Program version of it; although as of Spring 1986, industry ranked the St. George Basin 12th--behind North Atlantic, which was designated as a frontier exploration sale area in the Proposed Program. Indeed, St. George Basin has become a candidate for such designation, as described below in relation to Option A.2.e.

The benefit of scheduling these sales biennially instead of triennially is indicated by the cost of delay of developing the resources estimated to be in them (see Table 6 in conjunction with Table 2, above; and the section on the valuation of program alternatives, below).

The selection of this option would increase the workload of MMS.

Table 15 displays all sales which could be chosen in Option A.2.d.

## Flexibility Options

### -Frontier Exploration Sales

#### --Options

OPTION A.2.e.i - Confirm designation of the following sales as frontier exploration sales: Sale 114, Gulf of Alaska; Sale 127, Kodiak; Sale 136, Cook Inlet; Sale 133, Hope Basin; Sale 129, Shumagin; Sales 96 and 134, North ~~Atlantic; Sale 121, Mid-Atlantic; Sale 108, South Atlantic; and Sale 132,~~ Washington-Oregon.

OPTION A.2.e.ii - Add frontier exploration sale designation to all sales in either or both of the following areas: St. George Basin; and Norton Basin.

#### --Discussion of Frontier Exploration Sales

A frontier exploration sale is one for which industry interest is highlighted for re-examination before the start of the presale process. In those cases where new information on industry interest is needed, this re-examination will be based on responses to a Request for Interest published in the Federal Register several months prior to the Call, in addition to the annual review of the program under section 18(e). If interest is determined to be insufficient to justify proceeding with the sale, the sale can be delayed and a Request for Interest reissued on an annual or less frequent basis until interest is determined to be sufficient to hold the sale or the sale is cancelled.

Table 15

Current Leasing Schedule Overlap with the Biennial Leasing Option and Frontier Exploration Sales for the Proposed Final Program

| | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | Mid-1992 | No. of Sales |
|---|---|---|---|---|---|---|---|---|---|---|---|
| ATLANTIC | | | | | | | | | | | 4 |
| North | | 82 | | | | 96 | | | 134+ | | |
| Mid- | 76 | | | [111] | | | 121+ | | | | |
| South | 78 | | | [90] | | | | 108+ | | | |
| GULF OF MEXICO | | | | | | | | | | | 12 |
| Western | 74 | 84 | 102 | 105 | 112 | 115 | 122 | 125 | 135 | | |
| Central | 72 | 81 | 98 | 104 | 110 | 113 | 118 | 123 | 131 | S | |
| Eastern | 69(II) | 79 | 94 | | | 116 | | 137 | | | |
| PACIFIC | | | | | | | | | | | 7 |
| Southern CA | | 80 | | | | | 95 | | 138 | | |
| Central CA | 73 | | | | | | 119 | | S | | |
| Northern CA | | | | | | | 91 | | 128 | | |
| Washington-Oregon | | | | | | | | | 132+ | | |
| ALASKA | | | | | | | | | | | 18 |
| Beaufort Sea | | 87 | | | | 97 | | 124 | | S | |
| Chukchi Sea | | | | | | 109 | | | 126 | | |
| Norton Basin | 57 | | | [100] | | | 120 | | | | |
| Navarin Basin | | 83 | | | | 107 | | 130 | | S | |
| St. George Basin | 70 | | | [89] | | 101 | | S | | | |
| N. Aleutian Basin | | | | | 92 | | 117 | | S | | |
| Shumagin | | | | | | [86] | | | | 129+ | |
| Kodiak | | | | | | | | | | 127+ | |
| Cook Inlet | | | | | | | | | 136+ | | |
| Gulf of Alaska | | | | [88] | | | | | 114+ | | |
| Hope Basin | | | | | | | | | | 133+ | |
| | | | | | | | | | | Total | 41 |

Sales to the left of the vertical line include the current 5-year leasing schedule.
Sales to the right of the vertical line are part of this option for the Proposed Final Program.
S = Sale not yet numbered. Sale numbers are those in the Proposed Program.
+ = Frontier Exploration Sale.
[] = Sale cancelled

This approach is designed to add flexibility to the program by providing for the reasonable possibility that changes in geologic data and economic or other conditions could create bidding interest in the future in areas which now appear unattractive. For example, a substantial oil price increase (such as might result from an oil supply disruption), if anticipated to be relatively long-term, could make an area now unattractive to potential bidders into one which could be of interest to them. Other information of interest would include new geophysical data; new drilling data; new interpretations of existing data; and new estimates of costs of production. By requesting information and acting on it prior to the issuance of the Call, the risk of inappropriate expenditures for such sales would be reduced. One possible drawback of frontier exploration sales, however, is that the additional uncertainty as to whether they will be held might lead firms to avoid investing in data collection for them.

These sales would include those in frontier areas about which there are very inconclusive assessments of potential oil and gas resources based on exploration results (see Appendix E). Ensuring the early assessment of OCS oil and gas resources is one of the purposes of the OCS Lands Act Amendments (section 102(9)). Finally, the scheduling of frontier sales has been interpreted by the court to have beneficial effects concerning the consideration of equitable sharing required in section 18(a)(2)(B) (see California v. Watt (II) at 599 and Part II.C).

The frontier exploration sales proposed by the Draft Proposed Program were five single sales in Alaska areas (Gulf of Alaska, Cook Inlet, Hope Basin, Kodiak, and Shumagin). This proposal was designed to increase the flexibility of the schedule to respond to changes in economic conditions or new geologic and geophysical data. Sales in the latter four areas are proposed as single sales because they are in net social value Group IV and rank low in industry interest. Gulf of Alaska is also scheduled for a single sale even though it is in Group III because of low industry interest, reflected in the cancellation of Sale 88. In the Proposed Program, frontier exploration sale designation was also proposed for triennial sales in the North, South, and Mid-Atlantic and offshore Washington and Oregon, where the re-evaluation of industry interest prior to proceeding with the standard presale process was deemed appropriate. Triennial scheduling of these sales reflects their net social value Group II ranking.

The first sale offshore Washington and Oregon since 1964 would be scheduled, given that area's net social value ranking and industry interest. The sale for this area is scheduled late in the 5-year period in order to allow time for the necessary environmental studies to be performed. The time allotted for studies exceeds that required by section 20 of the OCS Lands Act and regulations at 30 CFR 256.82(c), which provide that a study for an area be commenced at least 6 months prior to holding a lease sale for that area. Studies planned for this or any other area are described in the MMS Regional Studies Plan prepared for each region.

For the Proposed Final Program, in response to the request of the Governor of Alaska, a new suboption has been added to extend the frontier exploration sale designation to St. George Basin and Norton Basin sales. St. George Basin ranked 12th in industry interest in Spring 1986, although its net social value ranking @$24/bbl. starting oil price is 10th. Norton Basin ranks 18th in both respects. Navarin Basin could also be considered for inclusion in this category based on its ranking (10th) in Spring 1986 comments by industry and the results of surveys of industry interest concerning Sale 107.

-Comments on Frontier Exploration Sales

° State Governors: Maine, New Hampshire, Massachusetts, Rhode Island, Connecticut, New Jersey, Delaware, Maryland, and North Carolina endorsed the scheduling of frontier exploration sales. Massachusetts recommended that States be notified when MMS issues a Request for Interest, and they requested that the interest level necessary to justify a sale be defined. They also requested that States be provided a summary of MMS/industry consultations. Alabama endorsed the concept of frontier exploration sales but requested increasing the number of such sales on the schedule. Oregon and Washington commented that the concept of frontier exploration sales confounds the intent of the OCS Lands Act, as amended, which calls for a precise description of timing and location. Alaska endorsed the frontier exploration sales proposed off Alaska and requested that such sales be scheduled in the St. George Basin and Norton Basin planning areas.

° State Agencies: New York Department of Environmental Conservation and Georgia Department of Natural Resources endorsed the concept of frontier explorations sales. The former also requested that a second request for industry interest be issued prior to the Proposed Notice of Sale.

° Local Governments: Bristol Bay Coastal Resource Service Area recommended that the Bering Sea OCS planning areas be designated as frontier exploration sales.

° Federal Agencies: EPA endorsed the concept of frontier exploration sales and recommended that such sales be scheduled in all planning areas where triennial leasing is proposed other than Southern California. NOAA commented that the uncertainty of frontier exploration sales could affect adversely the Environmental Studies program for Alaska planning areas. They also stated their intention to work closely with the MMS to ensure that the 5-Year Environmental Studies Management Plan is designed to make sufficient preliminary data available prior to the Request for Interest for each sale.

° Industry: Chevron endorsed the proposed frontier exploration sales. Shell expressed support for scheduling frontier exploration sales but objected to their tentative status and stated that the Request for Interest step is unnecessary. However, they recommended that if this step is adopted, it be reissued annually for areas in which industry interest has previously been found to be insufficient for proceeding with a sale. Exxon expressed concern that adding the Request for Interest step to the presale process may invite additional legal challenge. They recommended that industry interest instead be determined during annual review of the program.

° Environmental and Other Organizations: Massachusetts Audubon Society commented that frontier exploration sales are preferable to standard sales but stated that if such a sale is cancelled it should never be rescheduled. NRDC expressed opposition to the concept of frontier exploration sales, stating that their tentative status undermines State planning and MMS's commitment of money to environmental studies. They recommended that these sales not be scheduled initially but added in formal revisions of the program should circumstances change to make leasing in frontier areas viable.

-Supplemental Sales

--Options

OPTION A.2.f.i. Adopt annual sales of blocks outside of the Central and Western Gulf of Mexico: rejected and forfeited bid blocks offered in a prior period; and development blocks.

OPTION A.2.f.ii. Extend the supplemental sale concept to offer all unleased blocks on the same structure as the blocks offered.

--Discussion of Supplemental Sales

This option would add an annual sale to offer a small number of selected blocks in areas other than the Central and Western Gulf of Mexico: development blocks; and blocks on which bids were rejected or forfeited as a result of a sale in a prior period.

--Rejected and Forfeited Bid Blocks

The small annual reoffering of blocks which received bids which were rejected or forfeited as a result of a sale in a prior period would diminish any delay cost associated with offering the blocks 1 or more years later in a triennial sale. It would also provide for the timely offering of blocks based on evolving geological and geophysical information and would assure receipt of a fair return to the public for blocks on which the Government possesses the latest data.

Adding the ability to reoffer forfeited bid blocks adds to supplemental sales the potential for reoffering an additional type of high interest block. In the case of a forfeited bid block, industry interest was high enough to result in an acceptable bid, even if the deposit was subsequently forfeited by the high bidder. It needs to be considered that the reasons for that forfeiture may not be shared by other potential bidders.

Supplemental sales would continue to be scheduled as annual sales. Changing the ~~Proposed Program provision to allow the reoffering of rejected or forfeited bid~~ blocks resulting from a sale in a prior period rather than the preceding year could help ensure that all otherwise eligible blocks can be reoffered even if a supplemental sale Call were delayed for some reason.

--Development Blocks

A development block is one which is located on the same general geologic structure as an existing lease having a well with indicated hydrocarbons; the reservoir may or may not be interpreted to extend onto the block. One kind of development block is a block which is susceptible to drainage of hydrocarbons.

Failure to offer development blocks expeditiously could adversely affect the efficient production of the prospect's resources. For example, the expeditious identification and offering of development blocks susceptible to drainage would minimize potential losses in their sale value because as drainage continues, the net present value of the block being drained diminishes. In areas other than the Central and Western Gulf of Mexico (where annual sales provide for the expeditious offering of development blocks), the time intervals between sales could result in substantial losses in bonuses and royalties to the Government on development blocks.

This option would, in part, reintroduce the concept of OCS drainage sales on a basis compatible with the requirements of section 18. (Twelve drainage sales were held in the Gulf of Mexico between 1959 and 1978.) A further precedent for this provision under State law exists in Alaska Statutes 38.05.180(d) which allows the Commissioner of the Alaska Department of Natural Resources to issue leases in an area not included in a State 5-year leasing program if (1) the land to be leased was previously subject to a valid State or Federal oil and gas lease, or (2) the land is contiguous to land under State, Federal, or private leases and the Commissioner makes a written finding, after hearing, that leasing of the land would result in a substantial probability of early evaluation and development of the land to be leased.

Since the largest structure identified to date on the OCS covers approximately 35 blocks, even if an entire structure were offered in a supplemental sale, it would likely be small compared to the size of a standard sale. If a number of entire structures were added, however, the result could be different.

The Federal Register Notice which announced the Proposed 5-year OCS Leasing Program (50 FR 4816) specified that:

> [Supplemental sale] blocks will only be offered after compliance with the requirements of the National Environmental Policy Act, the OCS Lands Act, and other applicable statutes. The environmental assessment documentation for each of these sales would be released prior to the proposed notice of sale. If it is determined that an EIS is required for one or more blocks to be offered in one of these sales, revised presale milestones would be issued.

That Notice also included a typical milestone schedule for supplemental sales which included the following steps: Call; issuance of an environmental assessment (EA); proposed notice of sale; notice of sale; and sale. The Call will establish the maximum size of the sale and request comments from all parties on the blocks proposed for offering. A 45-day comment period is planned for responses to the Call. Any nominated development block outside the Call area would be considered for inclusion in the next supplemental sale or the next regular sale in the relevant planning area.

Since the function of an area identification--specifying blocks for environmental analysis--will have been performed prior to and announced in the Call, an area identification step as provided in the current regulations is not appropriate for supplemental sales. The results of Interior's consideration of comments submitted in response to the Call will be announced at the time the EA is issued. The EA will also indicate whether any additional environmental impact analysis would have to be done in order to be able to offer a block for lease. If an EIS would have to be prepared, revised milestones for that process would be issued if it were to be pursued. The public issuance of the EA is planned so that it can be reviewed prior to the issuance of the proposed notice of sale. The proposed notice will provide the Governors and local governments of affected States the opportunity to comment on the sale proposal, pursuant to section 19 of the OCS Lands Act. Comments on the EA and the proposed notice of sale will be considered for the decision on the final notice of sale.

This option, like the one selected for the Proposed Program, would schedule annual supplemental sales beginning with Sale SU-1.

--Compliance with the National Environmental Policy Act (NEPA)

To comply with NEPA, an EA would be written covering each development, rejected and forfeited block. If each of the blocks had been covered in an EIS within the last several years, the preparation of an EA regarding the leasing of these blocks could well be sufficient to comply with the requirements of NEPA. However, it may be necessary to prepare a new EIS or a supplemental EIS (or deleting from the supplemental sale the blocks whose offering would require an EIS) if the EA finds that significant additional environmental information has become available, or significant environmental impacts are identified which were not evaluated in a recent EIS.

--Development of Regulations for Supplemental Sales

A Notice of Proposed Rulemaking on supplemental sales will be published in the Federal Register. Comments in response to that Notice will be considered both for the final rulemaking and the Secretary's forthcoming decisions on the new program.

--Comments on Supplemental Sales

° State Governors: Connecticut endorsed the concept of supplemental sales. Florida commented that supplemental sales must not be held until social, economic, and environmental factors are considered and consultation with State and local governments is conducted. Florida also stated that supplemental sales must not be added if they will conflict with the objectives of the 5-Year Environmental Studies Plan. Alabama endorsed the concept of supplemental sales and recommended increasing the number of such sales. California gave qualified endorsement to the concept of supplemental sales but stated that the regulatory authority for conducting such sales is questionable. California recommended the promulgation of regulations prior to holding the sale pertaining to: block selection criteria; State and local government consultation in accordance with section 19 of the OCS Lands Act, as amended; and requiring unitization agreements for development of drainage and development tracts along with original discoveries. Alaska endorsed the proposed supplemental sales provided that the following conditions are met: the State and the public are allowed to comment prior to such a sale; the blocks proposed for sale were evaluated under the EIS alternative adopted; the State did not oppose leasing the proposed blocks in the presale planning process; and the proposed blocks would enhance drainage and development of the new discovery.

° State Agencies: Florida Coastal Resources Citizens Advisory Committee expressed opposition to supplemental sales. California State Water Resources Control Board commented that supplemental sales are unnecessary due to the heavy schedule of standard sales proposed. California Department of Justice stated that the concept of supplemental sales constitutes a violation of section 18(a) of the OCS Lands Act, as amended, since it fails to specify as precisely as possible those areas which will be offered for lease.

° Local Governments: City of Laguna Beach (CA) and Orange County (CA) recommended eliminating supplemental sales from the 5-year program. City of Newport Beach (CA), San Diego County (CA), City of San Luis Obispo (CA), and San Luis Obispo County (CA) expressed opposition to supplemental sales in combination with other features of the program. Newport Beach stated that supplemental sales in addition to standard sales would result in too much leasing. San Diego County stated that supplemental sales and the acceleration provision could result in continuous leasing in the Southern California planning area. San Luis Obispo County stated that supplemental sales and acceleration would overburden local planning agencies. Orange County (CA) noted supplemental sales in a resolution stating general opposition to the Proposed Program.

° Federal Agencies: EPA recommend that information distribution and review/comment milestones be established relative to the Proposed Notice of Sale for a supplemental sale. They further stated that such milestones should allow adequate time to review concerns raised in the National Environmental Policy Act process for the purpose of restructuring the Proposed Notice of Sale.

° Industry: API, NOIA, Chevron, and Shell specifically endorsed the proposed supplemental sales. AOGA expressed support for supplemental sales but recommended that the term "drainage and development blocks" be clearly defined to include all blocks located on a geologic structure in which a discovery has occurred. Exxon recommended that supplemental sales be broadened in scope. They also stated that preparation of a brief supplemental EIS would be appropriate for supplemental sales offering blocks which previously have been addressed by a draft EIS. BP Alaska commented that supplemental sales may not be effective for blocks on which bids have been rejected in the previous year.

° Environmental and Other Organizations: NRDC stated that there is no reason for supplemental sales to offer blocks on which bids were rejected in the previous year, as one year is too short a time to acquire new information which might indicate that the value of such blocks has increased. Massachusetts Audubon Society expressed opposition to supplemental sales. Oceanic Society and League of Women Voters of Santa Barbara expressed concern about supplemental sales. The latter stated that such sales will serve to confound efforts to anticipate and properly plan for the impacts of OCS leasing.

° Private Citizens: A number of commenters expressed opposition to the proposed supplemental sales.

<u>Acceleration Provision</u>

The acceleration provision is described in the summary of the Proposed Program, above, and in the <u>Federal Register</u> Notice which announced it (50 FR 4816). Comments on that provision are summarized in Appendix B. Based on a review of those comments, the acceleration provision was eliminated from further consideration by the decision of the Secretary on September 8, 1986.

<u>New Schedule Alternative</u>

<u>Option</u>

<u>OPTION A.2.g</u> Adopt the schedule for Options A.2.a and A.2.e, revised to delete Sale 127, Kodiak; delay until the next calendar year Sale 119, Central California, and Sale 132, Washington-Oregon; and schedule a combined Gulf of Alaska/Cook Inlet sale in 1991.

Discussion

The new schedule alternative (see Table 16) would modify elements of Options A.2.a and A.2.e, above. Changes from those options reflect additional responsiveness to comments and administrative considerations.

The deferral of leasing in Kodiak would respond to a request by the State of Alaska. Kodiak is projected to have a negligible net social value of leasing throughout the range of oil price assumptions. Kodiak was ranked 23rd by industry in Spring 1986--below the St. Matthew-Hall area, which had already been eliminated from the leasing schedule in both the Draft Proposed Program and Proposed Program.

Sale 119, Central California, would be delayed until 1990 so as to avoid scheduling three sales off California in the same year, and thereby relieve State parties who review and comment on leasing proposals.

Sale 132, Washington-Oregon, would be delayed from 1991 to 1992. This would respond to the request from the Governor of Washington to delay the sale so that the environmental data base can be improved for use in decision-making during the presale process.

Sale 114, Gulf of Alaska, and Sale 136, Cook Inlet, would be combined into a single sale in 1991. This would follow the precedent set by Sale 88, Gulf of Alaska/Cook Inlet, which was scheduled by the 1982 program (but canceled in 1986). It should be noted that the combination of these two contiguous areas will result in a relatively small increase in the size of the Gulf of Alaska sale. Combining presale steps would reduce the administrative burden involved for all parties.

Table 16

Current Leasing Schedule Overlap with New Schedule Alternative
for the Proposed Final Program

| | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | Mid-1992 | No. of Sales |
|---|---|---|---|---|---|---|---|---|---|---|---|
| ATLANTIC | | | | | | | | | | | 4 |
| North | | 82 | | | | 96 | | | 134+ | | |
| Mid- | 76 | | | [111] | | | 121+ | | | | |
| South | 78 | | | [90] | | | | 108+ | | | |
| GULF OF MEXICO | | | | | | | | | | | 12 |
| Western | 74 | 84 | 102 | 105 | 112 | 115 | 122 | 125 | 135 | | |
| Central | 72 | 81 | 98 | 104 | 110 | 113 | 118 | 123 | 131 | S | |
| Eastern | 69(II) | 79 | 94 | | | 116 | | | 137 | | |
| PACIFIC | | | | | | | | | | | 6 |
| Southern CA | | 80 | | | | | 95 | | | 138 | |
| Central CA | 73 | | | | | | | 119 | | | |
| Northern CA | | | | | | | 91 | | | 128 | |
| Washington-Oregon | | | | | | | | | | 132+ | |
| ALASKA | | | | | | | | | | | 12 |
| Beaufort Sea | | 87 | | | | 97 | | | 124 | | |
| Chukchi Sea | | | | | | 109 | | | 126 | | |
| Norton Basin | 57 | | | [100] | | | 120 | | | | |
| Navarin Basin | | 83 | | | | 107 | | | 130 | | |
| St. George Basin | 70 | | | [89] | | | 101 | | | | |
| N. Aleutian Basin | | | | | 92 | | | 117 | | | |
| Shumagin | | | | | | [86] | | | | 129+ | |
| Kodiak | | | | | | | | | | [127+] | |
| Cook Inlet (CI) & Gulf of Alaska (GOA) | | | | [88] | | | | | CI & GOA + | | |
| Hope Basin | | | | | | | | | | 133+ | |
| | | | | | | | | | | Total | 34 |

Sales to the left of the vertical line include the current 5-year leasing schedule.
Sales to the right of the vertical line are part of this option for the Proposed Final Program.
S = Sale not yet numbered. Sale numbers are those in the Proposed Program.
+ = Frontier Exploration Sale. [] = Sale cancelled

## Valuation of Program Alternatives

### Introduction

The decisions the Secretary will make on timing, location, and subarea deferrals as part of the 5-year program, together with the decision on the presale process to be used, will significantly influence the pace of OCS leasing and development. Consequently, these decisions will influence the timing of costs incurred and benefits realized from OCS oil and gas development. In general, the faster that leases are made available for exploration in the next 5-year program, the sooner production will be achieved. In addition, benefits will be higher if the lower cost resources are found and produced first. The objective of the schedule valuation analysis is to present for the Secretary's consideration a link between the rate and sequence of leasing and the timing and the magnitude of the benefits that can be expected. Similarly, the valuation analysis for various subarea deferral program alternatives demonstrates how resource availability at the time of sale can influence the net benefits which could be expected from each proposal. Simply put, this section provides estimates of the potential net economic benefits to the Nation of each of the alternative schedules and the estimated potential reduction in benefits associated with the subarea deferral alternatives.

The program alternatives examined in this valuation analysis include:

° Schedule Alternatives

1. The Proposed Program update (i.e. options A.1.a (setting planning areas and subarea deferrals) plus A.2.a (standard sales) plus A.2.e (frontier exploration sales))--See schedule in Table 14

2. Option A.2.b, which would add a sale in the Straits of Florida

3. Option A.2.c, which would defer sales in up to six planning areas

4. Option A.2.d, which would replace the triennial pace of leasing in the Proposed Program update with a biennial pace in up to eight planning areas--See schedule in Table 15

5. Option A.2.g, which revises the schedule for sales--See schedule in Table 16

° Additional Subarea Deferral Alternatives

6. Option A.1.b, updated the Proposed Program schedule with additional subarea deferrals

7. Option A.1.f, the Bering Sea Proposal of the Institute for Resource Management

8. Options A.1.c, the alternative California proposal of Governor Deukmejian

9. Option A.1.d, the alternative California proposal of Congressman Regula

10. Option A.1.e, the alternative California proposal of Congressman Panetta

11. Option A.1.g, the amalgamated proposal from the Draft Proposed Final Program for Leasing Offshore California

Background

This valuation analysis was prepared to estimate the net social value associated with each program alternative mentioned above. The results reflect differences in value associated with the particular option being considered and therefore differ from the net social value estimates for the planning area as a whole (as developed in Appendix F and displayed in Table 12.1). That area-by-area net social value analysis was prepared based on the assumption that all leasable resources were leased at the beginning of the program for the purpose of comparing whole planning areas. Based on the results of the area-by-area comparison of net social value and other section 18 considerations, various scheduling and subarea deferral options were developed. This valuation exercise provides for a comparison of these options showing the effects of sale timing, location, and resource availability on the estimated value for each program alternative.

For his decision on the Proposed Program, the Secretary was provided with an assessment of the value of the base schedule option. For the Proposed Final Program, this section has been expanded to provide information on how the value of the Proposed Program schedule (as updated) compares to other options before the Secretary--that is, what effect the various OCS sale scheduling and subarea deferral options could have on the expected net benefits to the Nation from OCS oil and gas leasing and development.

The results of the valuation analysis should not be viewed as exact because they hinge upon the assumptions surrounding many uncertain variables, such as undiscovered resource potential, resources expected to be leased in future sales, and future oil prices. However, the assumptions and methodology used in the analysis were consistent across options, so that general conclusions could be drawn about the changes in net social value which could be expected from different program alternatives.

Figure 3 graphically depicts the significant contribution to future OCS oil and gas production which could be realized from leasing under the 5-year program. ~~The heavily shaded area of the production curve reflects projected~~ future oil and gas production from the resources expected to be leased from the Proposed Program Schedule. /1. The graph shows the potential contribution to meeting national energy needs of the new 5-year program.

Description of Analysis

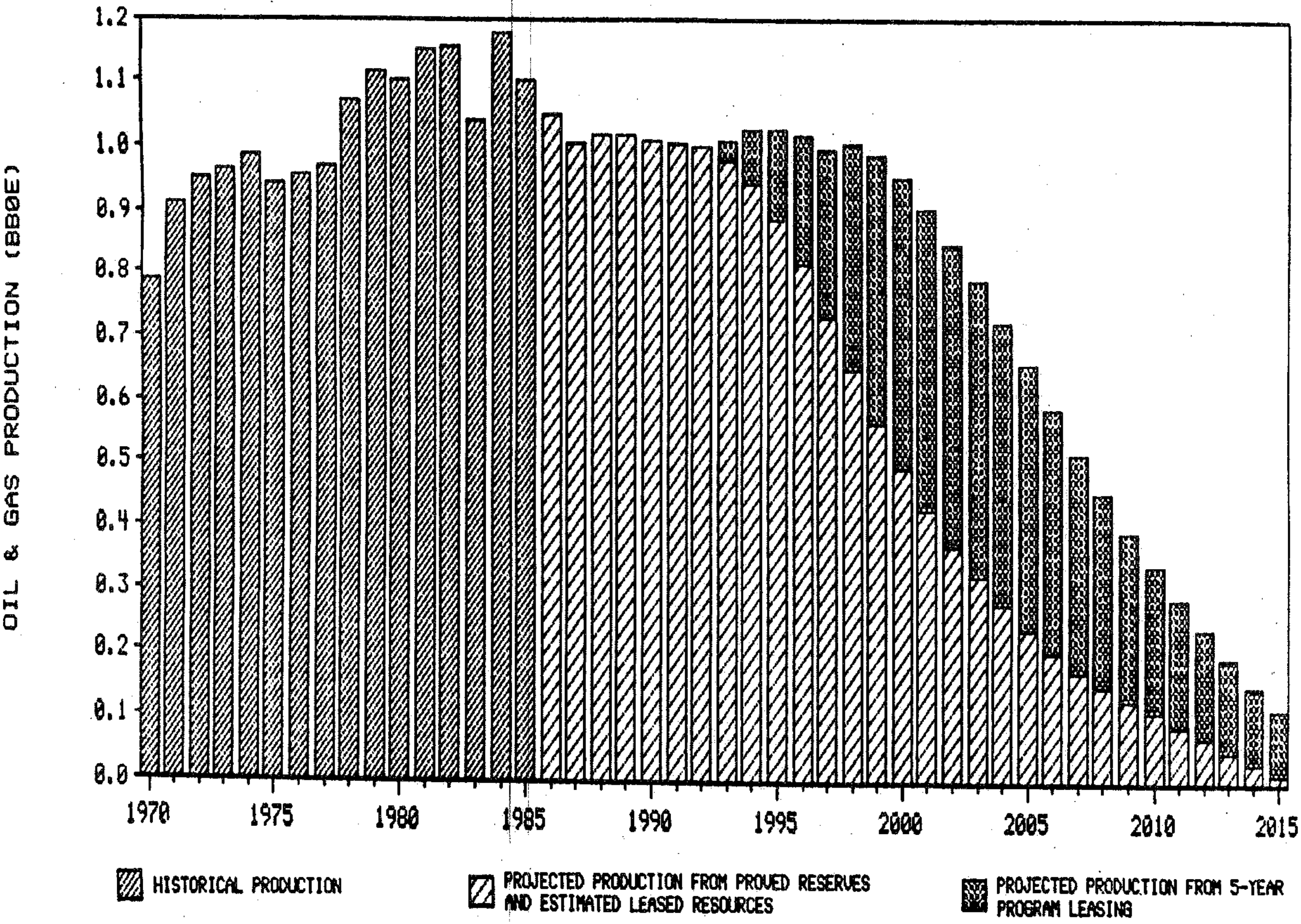
The Secretary's Proposed Program (as updated) is used as the basis for comparison with other Proposed Final Program alternatives. The Proposed Program schedule consists of 27 standard sales and 9 frontier exploration sales in 21 planning areas. As described in the options section, the sale schedule was derived by

/1 Note that production estimates for this graph were based on estimates of risked economically recoverable resources from an analysis which assumed starting oil prices of $29 per barrel. If prices remain at current low levels, the shape of the graph would likely be different, with a decline in the 1990's due to a shift in capital away from exploration in the late 1980's. There are many uncertainties inherent in the these projections. All assumption used are consistent with those used for the estimates of future leasing and associated infrastructure in the SID and EIS.

FIGURE

HISTORY & PROJECTION OF OIL & GAS PRODUCTION
UNITED STATES OCS AREAS

(INCLUDES THE POTENTIAL CONTRIBUTION FROM 5-YEAR PROGRAM LEASING)



considering a combination of factors including net economic value, social costs (reflecting, in part, marine productivity and environmental sensitivity), composite industry interest rankings, and other section 18 considerations.

During the presale process, the Secretary will make a determination as to the specific size of the lease sale. For this analysis, resources expected to be leased from each sale were estimated assuming that OCS acreage will be offered under the "focusing on promising acreage" presale process (see Appendix R).

The same data developed for area-by-area net social value, derived from the estimates of net economic value (Appendix F) and social costs (Appendix G), were used to value the sales of each program alternative. However, unlike the net economic value figures which estimated the value of the production of all leasable resources if leased in mid-1987, the valuation of program alternatives required a projection of the amount of resources which would be leased at the time of each lease sale. From this projection, net economic value at the time of sale was estimated. The associated social cost attributable to production from that sale was deducted to determine net social value for each sale. These future values were then discounted to present value (i.e., 1987 dollars) to serve as a basis for comparing the net social value of each program alternative.

In order to fully compare the program alternatives, net social value for resources remaining unleased at the end of the 5-year program is also estimated. These estimates are important to consider when comparing program alternatives because the value of those alternatives which are expected to result in the early leasing of most resources could be overstated if only results for 5-year program leasing were examined. This is the case because proposals which defer more resources from this 5-year program can leave in the ground resources which, if leased in later years, would contribute economic benefit to the Nation. /1 In part, to simplify the analysis, the remaining unleased resources were valued as if all were available for leasing in the first sale of the next 5-year program. All subareas proposed for deferral under all program alternatives were assumed to remain permanently unavailable for leasing. (The only exception is for the Regula proposal--see Appendix R.) Alternative assumptions could be made but were excluded to simplify the analysis, especially since it is difficult to predict with any reliability the ultimate disposition of each subarea deferral.

A detailed discussion of the methodology used for the valuation analysis can be found in Appendix R, "Estimating Procedures Used for Valuation Analysis".

Valuation analysis has also been done for the alternative California proposals (i.e., Governor Deukmejian's, Congressman Regula's, Congressman Panetta's, and the amalgamated proposal) to determine what effects the differences in proposals will have on estimated net social value for California planning areas. The

/1 However, in most cases, given the economic assumptions of the 5-year program analysis, the higher values associated with later leasing of remaining resources will not offset the sizeable economic benefits from earlier leasing. In some of the low price cases, as found in the Appendix F economic analysis, certain low-valued prospects realized a gain in value from real oil price growth sufficiently large to offset the effects of discounting future production revenue to present value. (See discussion of cost of delay in Appendix F).

results of the valuation analysis for the California proposals are presented separately, because of a slight change in the methodology used to value remaining resources. Since the Regula and Panetta proposals contained provisions for subarea deferrals beyond this 5-Year Program, it was necessary, for analytical purposes, to extend the valuation methodology used for the 5-Year element to the remaining resources; that is, to project resources expected to be leased beyond the 5-Year Program given the stated provisions of each proposal. Under this methodology, resulting values can be disaggregated to examine value associated with only the 5-Year leasing component, or aggregated to examine total net social value for the 5-Year Program leasing and the potential value of remaining resources.

Results of Analysis

Results of the analysis are shown in detail in Appendix R and summarized below. Values were estimated for both a low oil price case and a high oil price case (i.e., 1984 starting prices of $14 and $29 per barrel, respectively). The uncertainty of estimating the future value of undiscovered oil and gas has been reflected in the computation of a range of net social value estimates for each planning area based on this $15 spread in the starting price of oil. The differences in results under the low and high price cases is attributable to the changes in net economic value estimates with different starting oil price assumptions. Estimates of resources expected to be leased by sale was not varied for different price assumptions. (See Appendix R for further discussion).

Table 17.1 is a summary of the value of the updated Proposed Program's planning areas (minus deferrals) and schedule of standard sales (option A.2.a) and frontier exploration sales (option A.2.e). Given the stated economic assumptions, the present net social value of resources projected to be leased during the 5-Year Program range from approximately $12 to $39 billion (from the low to the high price case). The value of the remaining resources ranges from $9 billion to $34 billion.

Table 17.2 shows estimates of the changes in value from the Proposed Program update which could be expected from selection of schedule options A.2.b through A.2.g. Also shown is the change in value associated with additional subarea deferral options (Options A.1.b and f).

Using the value of the Proposed Program update as a basis for comparison, one can draw certain conclusions from these tables. Each of the options represents an increase or decrease in potential value to the Nation as compared to the reference point. For example, options which add sales or accelerate sales (such as options A.2.b and A.2.d) result, on the whole, in an increase in the expected net social value of the 5-year program. The increase in discounted net social value for schedules with earlier sales results from the effects of discounting values generated over time to account for society's time-preference in exchanging consumption now for consumption in the future (at an 8 percent real discount rate). In almost all planning areas, the advantage of earlier realization of benefits more than offsets the loss due to the foregone growth in value from higher resource prices over time. Where this is not the case, royalties, taxes and the minimum bid reduce the likelihood that such prospects would be leased and developed prematurely. Options which allow for the cancellation of sales or deferral of subareas (such as Options A.2.c and A.2.g) result in a reduction of the estimated value of the Proposed Program update.

Table 17.1 

Value of Resources Expected to be Leased Under
the Proposed Program 5-Year Schedule and
Value of Remaining Unleased Economically Recoverable Resources /1
($1987 Millions, Except Totals)

| | Discounted Net Social Value /2 | | | |
|---|---|---|---|---|
| | Low Price Case | | High Price Case | |
| Planning Area | 5-Year Program Leasing (Mid-1987 to Mid-1992) | Value /3 of Remaining Unleased Resources | 5-Year Program Leasing (Mid-1987 to Mid-1992) | Value /3 of Remaining Unleased Resources |
| North Atlantic + | $77 | $179 | $215 | $439 |
| Mid-Atlantic + | $189 | $444 | $744 | $939 |
| South Atlantic + | $98 | $681 | $344 | $2,250 |
| Western Gulf of Mexico | $3,201 | $3,647 | $10,858 | $14,481 |
| Central Gulf of Mexico | $6,005 | $3,021 | $15,563 | $10,171 |
| Eastern Gulf of Mexico | $100 | $341 | $716 | $1,419 |
| Southern California | $983 | $395 | $3,304 | $1,256 |
| Central California | $213 | $88 | $924 | $350 |
| Northern California | $465 | $124 | $1,713 | $487 |
| Oregon-Washington + | $122 | $93 | $348 | $209 |
| Beaufort Sea | $112 | $6 | $793 | $20 |
| Chukchi Sea | $59 | $82 | $314 | $352 |
| Norton Basin + | $8 | $12 | $53 | $81 |
| Navarin Basin | $324 | $155 | $1,940 | $706 |
| St. George Basin + | $63 | $122 | $520 | $677 |
| N. Aleutian Basin | $22 | $3 | $90 | $11 |
| Shumagin + | $3 | $0 | $18 | $2 |
| Gulf of Alaska + | $8 | $35 | $37 | $195 |
| Cook Inlet + | $2 | $1 | $14 | $5 |
| Kodiak + | $6 | $3 | $36 | $14 |
| Hope + | $3 | $1 | $13 | $3 |
| Totals: | $12 billion | $9 billion | $39 billion | $34 billion |

\+ Planning area includes one or more sales which may be designated as frontier exploration sales under options A.2.e.i or ii.

/1 The uncertainty associated with estimating resources and net social value, as described throughout the text of the SID and this appendix, is compounded in the formulation of a leasing schedule. Furthermore, the relative uncertainty in the numbers in this table is, in part, based on the adequacy of data for each planning area. (See Table 12-1 in this SID and Appendix E.)

/2 Net social value is discounted to mid-1987--the projected start of the 5-Year Program. Totals may not add due to rounding.

/3 The values of remaining unleased resources do not reflect estimates of resources in currently uneconomic prospects which become economic as hydrocarbon prices increase in the future. See Appendix F, section V.C.

TABLE 17.2

ESTIMATED CHANGE IN VALUE FOR ALTERNATIVE PROGRAM OPTIONS

DISCOUNTED NET SOCIAL VALUE ($1987 Millions)*

| | LOW PRICE CASE | | HIGH PRICE CASE | |
|---|---|---|---|---|
| | 5-YEAR PROGRAM LEASING (mid-1987 to (mid-1992) | VALUE OF REMAINING 1/ RESOURCES | 5-YEAR PROGRAM LEASING (mid-1987 to mid-1992) | VALUE OF REMAINING 1/ RESOURCES |
| VALUE OF THE PROPOSED PROGRAM AS UPDATED (option A.1.a, A.2.a-standard sales, and A.2.e-frontier exploration sales) (see Table 14) | $12,061 | $9,431 | $38,556 | $34,065 |
| CHANGE IN VALUE FROM UPDATED PROPOSED PROGRAM FOR SELECTION OF OPTIONS: | | | | |
| OPTION A.2.b --Add sale in Straits of Florida | $7 | $13 | $26 | $37 |
| OPTION A.2.c --Defer sales | ($1,882) | $1,627 | ($6,594) | $5,618 |
| OPTION A.2.d --Biennial sales | $81 | ($40) | $490 | ($60) |
| OPTION A.2.g --New Schedule Alternative | ($22) | $3 | ($111) | $28 |
| OPTION A.1.b --Additional subarea deferrals | ($37) | ($212) | ($150) | ($659) |
| OPTION A.1.f --IRM proposal | ($3) | ($32) | ($13) | ($189) |

* Numbers in parenthesis mean a reduction in value.
/1 Assumes deferred subareas remain unavailable for leasing after deferral period runs out.

Table 17.3 illustrates the relative differences in the value estimates for the subarea deferral element of each of the California proposals. (See Appendix R for detailed results). Resulting total values are for the three California planning areas only. The other elements of these proposals not directly related to the size, timing, and location of leasing are analyzed in the California Analysis document and in the EIS. The results are displayed for the estimated value of leasing during the 5-year program, during the period 1992-2000, and after the year 2000. All three results are important since proposals which would defer more resources from the new 5-year program leave hydrocarbons in the ground which, if produced in the future, could have higher estimated value in subsequent years relative to proposals which would defer less. However, results of this analysis indicated that the values associated with leasing the remaining resources of the alternative proposals were not high enough to offset the sizeable benefits that would be expected to be realized from the greater availability of resources, earlier in time, of the February 1986 Proposed Program for the California OCS.

Table 17.3 divides value estimates remaining after the 5-year program into the estimated value of resources expected to be leased for mid-1992 through 2000 and the value of resources expected to be leased after the year 2000. This was necessary since Congressman Regula's and Congressman Panetta's proposals are specified for 13 years. The value estimated for the 5-year program leasing can be added to the value estimated for leasing during the mid-1992 to 2000 period to compare the proposals on a 13-year basis.

The value estimated for the resources remaining beyond the year 2000 can also be added to compare the proposals and their outyear ramifications in the broadest sense (assuming that leasing rates and subarea deferrals are maintained in the outyears as specified in each proposal and assumed for this analysis). All subareas proposed for deferral under the four proposals were assumed to remain permanently unavailable for leasing. The only exception is the subareas which Congressman Regula specified to become available for leasing after 1992. Given this exception, the resources expected to be leased, and the resulting value of the Regula proposal, are comparatively high for the 1992-2000 period. Similarly, restricting the availability of industry interest blocks under the Panetta proposal's limit of 50 industry interest blocks per 5-year period resulted in comparatively high values for the Panetta proposal in the post-2000 period.

The results of the valuation analysis of the five proposals are largely affected by the amount and resource potential of acreage proposed for deferral. Subarea deferrals create potential economic losses by delaying the search for oil and gas resources beyond the time when oil prices are likely to rise. Greater levels of resource availability for leasing during the 5-year program could improve the likelihood that discoveries would be made that could result in production in the 1990's when dependence on imported oil may reach levels that could affect national security or economic well-being.

In examining the results of the valuation analysis, it is important to consider both price cases. Oil prices are currently relatively low; however, the reader's focus should not be limited to the results for the low price case. Given that the earliest possible California production from resources leased during the 5-year program would be during the 1990's and could continue for 18 years or more, it is the prices that are expected during that time and beyond which are relevant.

TAL. . 17.3

## VALUATION OF CALIFORNIA PROPOSALS

DISCOUNTED NET SOCIAL VALUE OF RESOURCES EXPECTED TO BE LEASED DURING THE 5-YEAR PROGRAM & REMAINING ECONOMICALLY RECOVERABLE RESOURCES
($1987 MILLIONS)

| | LOW PRICE CASE* VALUE FOR CALIFORNIA PLANNING AREAS | | | HIGH PRICE CASE* VALUE FOR CALIFORNIA PLANNING AREAS | | |
|---|---|---|---|---|---|---|
| | 5-Year Program leasing (mid-1987 to mid-1992) | Leasing of Remaining Resources** (mid-1992 to mid-2000) | Leasing of Remaining Resources** (mid-2000 and beyond) | 5-Year Program leasing (mid-1987 to mid-1992) | Leasing of Remaining Resources** (mid-1992 to mid-2000) | Leasing of Remaining Resources** (mid-2000 and beyond) |
| CALIFORNIA PROPOSALS | | | | | | |
| OPTION A.1.b --FEBRUARY 1986 PROPOSED PROGRAM DECISION (updated) | $1,662 | $307 | $189 | $5,941 | $1,261 | $472 |
| OPTION A.1.c --GOVERNOR DEUKMEJIAN's PROPOSAL | $1,234 | $185 | $81 | $4,593 | $644 | $207 |
| OPTION A.1.d --CONGRESSMAN REGULA's PROPOSAL | $1,385 | $385 | $165 | $5,119 | $1,494 | $384 |
| OPTION A.1.e --CONGRESSMAN PANETTA's PROPOSAL | $628 | $166 | $197 | $1,998 | $685 | $584 |
| OPTION A.1.g --AMALGAMATED PROPOSAL | $1,511 | $288 | $160 | $5,554 | $1,141 | $370 |

* A low and high price case is used to capture the effects on value from alternative price path assumptions. The low and high starting prices of $14 and $29 per barrel reflect a range of weighted average FOB prices of U.S. imports of oil at the time when the 5-year program analysis began in 1984. For the Pacific region, these 1984 prices would equate to about $15 and $32 respectively, if expressed in 1987 dollars. For both the low and high cases, these oil prices are assumed to grow at a 1-percent annual real rate. As a simplifying assumption, resources expected to be leased in the series of sales for each proposal remain the same under both price cases.

** Assumes deferred subareas are not available for leasing after deferral period runs out.

The resulting valuation estimates are highly sensitive to the assumptions employed. The ultimate benefits and costs associated with this 5-year program will also differ from the results of this analysis because of, among other things, 1) changes in the sale timing (e.g., postponement of sales), or 2) specific lease sale decisions regarding subarea deferrals and sale size. Therefore, the assumptions made for the purposes of the valuation analysis, together with the uncertainties associated with estimating economic value and social costs, should be expected to have a compounding effect on the results. Furthermore, the relative uncertainty in the results is, in part, based on the adequacy of data for each planning area. (See Table 12.1 in this SID and Appendix E.)

This valuation analysis is only one of the factors that the Secretary considers in his decisions on the 5-year program. The section 18 considerations are discussed earlier in Part III of this SID. Nevertheless, the calculation of net social value for the program alternatives adds further information bearing on the potential economic impacts of timing and location decisions for the 5-Year OCS Leasing Program.

3. Estimated Appropriations and Staffing Requirements for the Proposed Final 5-Year Leasing Program

Section 18(b) of the OCS Lands Act requires an estimate of appropriations and staffing levels necessary to carry out the 5-year leasing program. These estimates are summarized in the following table and are presented in more detail in Appendix T.

The estimated resources indicate requirements for not only the MMS but for other Department of the Interior Bureaus and Offices as well. It is important to note that these are initial estimates of resource requirements and that these estimates may change as agency budgets are refined during the annual budget appropriation processes of the Department, the Office of Management and Budget, and the Congress.

It should be noted that resources for the prelease activities (Categories I, II and III of Appendix T) for fiscal years 1988 and beyond only provide estimated costs and full-time equivalent positions for those sales included in the options indicated below. There are no estimates of resource requirements for the work on prelease planning activities for sales which would be included in the 5-year program following the one ending in mid-1992. The effect of this is that there appears to be a decline of needed resources in the outer fiscal years.

Table 17.4

Estimated Appropriations and Staffing Requirements
For the 5-Year Program
($ in Millions)

| Fiscal Year /Option | Minerals Management Service | | Fish & Wildlife Service | | Office of the Solicitor | |
|---|---|---|---|---|---|---|
| | Funds | Staff | Funds | Staff | Funds | Staff |
| Proposed Prg. Update (Table 14) Option A.2.a +A.2.e.i. | | | | | | |
| 1987 | $105.8 | 1,289.3 | $ .2 | 3.0 | $ .4 | 7.0 |
| 1988 | 106.9 | 1,273.0 | .2 | 3.0 | .4 | 7.0 |
| 1989 | 113.6 | 1,268.3 | .2 | 3.0 | .4 | 7.0 |
| 1990 | 110.1 | 1,283.0 | .1 | 3.0 | .4 | 7.0 |
| 1991 | 103.0 | 1,251.6 | .1 | 3.0 | .3 | 7.0 |
| 1992 | 79.5 | 1,111.6 | .1 | 2.0 | .3 | 7.0 |
| New Schedule Alternative (Table 16) Option A.2.g | | | | | | |
| 1987 | $105.8 | 1,289.3 | $ .2 | 3.0 | $ .4 | 7.0 |
| 1988 | 106.9 | 1,273.0 | .2 | 3.0 | .4 | 7.0 |
| 1989 | 112.1 | 1,270.2 | .2 | 3.0 | .4 | 7.0 |
| 1990 | 110.5 | 1,265.5 | .1 | 3.0 | .4 | 7.0 |
| 1991 | 103.4 | 1,251.1 | .1 | 3.0 | .3 | 7.0 |
| 1992 | 80.3 | 1,113.8 | .1 | 2.0 | .3 | 7.0 |

III.B. Size Options for the Proposed Final Program

Options

OPTION B.1.a Focus on Promising Acreage [Suboptions for further specification of this option are discussed below]

OPTION B.1.b Tract Selection Sales

i. Hold sales based on tract-specific nominations generally offering up to 2 million acres.

ii. Hold sales based on tract-specific nominations with actual acreage offered dependent on the magnitude of nominations, hydrocarbon potential, and environmental and multiple-use considerations.

OPTION B.1.c Hold Areawide Sales. For the purpose of this option, "areawide sales" has the meaning of the initial areawide approach described in Part III of the Proposed Final Program Secretarial Issue Document.

Discussion of the Presale Process

-Comparison of the Three Presale Approaches for Standard Sales

Three basic presale approaches have been used for OCS general lease sales: (1) "tract selection" (Option B.1.b); (2) the initial "areawide" process (Option B.1.c); and (3) more focused approaches--most recently, "focusing on promising acreage" (Option B.1.a). These approaches will be described and compared with special attention to their effects on multiple-use and environmental considerations, planning and coordination with States and localities, and exploration.

The current presale process (described in detail in Appendix L) extends over a period of about 2 years. To compare the tract selection, areawide, and focusing approaches one needs to consider a wide range of issues. Some of these will be addressed here and others appear elsewhere in the SID. Comments on this issue which were received in response to the February 1986 request are summarized in Appendix B. Fair market value considerations are discussed in Part II.E and Appendices K and P. Further data and analysis on the tract selection and areawide leasing approaches appear in Appendix P.

-Overview

Historically, these different approaches represent distinguishable combinations of policies and procedures. The tract selection approach was used until 1982. The initial areawide leasing approach was used in Sale 76, Mid-Atlantic, held in April 1983, through Sale 79, Eastern Gulf of Mexico, held in January 1984. A modified areawide leasing approach was inaugurated in January 1984. A further modification, focusing on promising acreage, was inaugurated in March 1985, with the issuance of the Draft Proposed Program.

The February 1986 Federal Register Notice announcing the Proposed Program described focusing on promising acreage in the following terms:

> The proposed presale process, focusing on promising acreage, determines the size of lease sales. The Department uses an extensive consultation and balancing process to offer acreage where OCS leasing would be environmentally sound and has a potential to lead to exploration for oil and gas resources. In this process, the Department uses information and nominations obtained from affected States, local governments, Federal Agencies, the public, and potential bidders, as well as MMS analyses. Focusing on promising acreage aims at the resolution of conflicts early in the presale process by the achievement of consensus on key issues--especially concerning acreage with low MMS resource estimates and low industry interest.
>
> Early steps in the presale process include the Call for Information and Nominations and the Area Identification. The Call depicts the area of hydrocarbon potential projected by MMS. The Call may be tailored on a case-by-case basis to exclude portions of the planning area (as in the exclusion of the Flower Garden Banks from the 1987 Western Gulf of Mexico Sale). In Area Identification, responses to the Call are used in structuring the area to be analyzed in the EIS. In addition to these early steps, consultation also occurs at later steps in the presale process.

The tract selection sale procedures used in prior years restricted the location and the amount of acreage offered, in part because of opposition to leasing and in part because of administrative constraints on the number of specific tracts that were processed through the environmental impact analysis and presale tract evaluation steps in preparing for lease sales. Tract value estimates were prepared for all tracts to be offered and were completed prior to the date of the sale. As a result of these constraints, only a portion of the tracts nominated by potential bidders were offered in the subsequent sale. The tracts selected from those nominated tended to be those that received nominations from more than one or two firms. One of the objectives of areawide leasing was to give more freedom to oil and gas exploration firms in the location and the rate of investments in exploration and development of OCS oil and gas prospects. A number of procedural changes were made in order to achieve this objective, allowing the higher leasing rates of 1983 and 1984.

The three approaches differ in two general ways. First, the acreage offered for lease tends to be largest in areawide sales and smallest in tract selection sales with focusing on promising acreage in the middle. The largest areawide sale (over 58 million acres) included about 20 times the acreage of the largest tract selection sale (about 3 million acres). Second, tract selection relies more on governmental as opposed to private industry judgment in the course of the presale process. Both the areawide approach and focusing on promising acreage give more weight to a nomination submitted by a single firm than was the case under tract selection.

Focusing on promising acreage differs from the areawide approach in that the former provides more flexibility for the resolution of conflicts early in the presale process--especially concerning low-resource, low-interest acreage. The magnitude and timing of deferrals ("focusing") from sales since January 1984 are documented in Appendix O.

It is possible to combine tract selection or areawide procedures with a variety of policies concerning the size of a sale. For example, areawide leasing procedures can accommodate sales covering a whole planning area or much smaller sales. Likewise, with the post-sale evaluation procedures in place--procedures designed for larger tract selection sales and then used for areawide sales--tract selection sales could be larger than their historical limit of 2 to 3 million acres. Nonetheless, the term, "tract selection" as used by most parties connotes the historical approach used in OCS leasing prior to 1982: sales offering generally 1 to 2 million acres.

In addition to the presale procedures for determining the amount of acreage to be offered for lease, it is possible to influence the amount of acreage actually leased in a given sale by appropriately setting the minimum bid that can be submitted. The higher the minimum bid, the lower the number of tracts of sufficient value to be worth acquiring at bids at least that high. Thus the minimum bid is in some ways an alternative or a supplement to presale procedures for controlling the actual pace and timing of leasing. The minimum bid also has competition and revenue effects and is therefore discussed in Part III.C. Other possible approaches to limiting the amount of acreage leased are described in the section on decision options regarding sale size, below.

-Presale Procedures for the Different Approaches

The key differences between the three approaches can be seen in the early presale steps. The first step in a tract selection decision process is the Call for Nominations. The Call asks industry to nominate tracts or descriptions of areas within the Call area. Companies are requested to rank tracts or areas nominated by priority of interest (high, medium, low). The Call also requests comments from the States, other Federal Agencies, and the public regarding which tracts or areas should or should not be considered for leasing. Comments and nominations are analyzed by the MMS along with environmental profiles and data on the area, including geologic and resource data and information from resource reports requested from other Federal Agencies prior to issuance of the Call for Nominations. After consultation with affected States, there is a tentative selection of tracts or areas to be analyzed further in the EIS as the proposed Federal action. The tract selection approach usually narrowed down the size of the sale area to tracts or areas rated high or moderate in hydrocarbon potential by the MMS and tracts or areas nominated by a number of firms determined on a sale-specific basis up to the maximum administratively-determined size of the sale. A tract or area nominated by a single firm, even if ranked high priority by the firm, was not assured of selection for further study (even before the questions of multiple-use and environmental protection were reached). In the past, the maximum size of tract selection sales was between 2 and 3 million acres.

Under the initial areawide approach, the Call for Nominations was replaced by the Call for Information. The Call for Information can request information and expressions of interest on broad areas within virtually the entire planning area. Expressions of interest could overlap or extend beyond MMS's identification of the area of hydrocarbon potential within the planning area. The Call could also solicit information on particular tracts or areas.

A modification of the areawide approach was the reintroduction of the term "nominations," often associated with block-by-block expressions of interest, to the Call. This step was taken with the publication of the Call for Information and Nominations for Sale 109, Barrow Arch [Chukchi Sea] (50 FR 3870, January 28, 1985).

Focusing on promising acreage contemplates the further modification in which Call areas could be tailored on a case-by-case basis to exclude parts of the planning area. For example, the Call for Sale 110, Central Gulf of Mexico, and the 1987 Western Gulf of Mexico sale excluded the environmentally sensitive Flower Garden Banks from the Call area. More dramatically, the Call for Sale 91, Northern California, excluded 96 percent of the planning area.

The process of focusing on promising acreage is a flexible approach whose results can range from "areawide" size sales to "tract selection" size sales, depending on MMS resource estimates, industry nominations, environmental issues, and use conflicts. A presale process of focusing on promising acreage provides an alternative and/or supplement to the deferral of subareas at the 5-year program stage for the purpose of achieving an early resolution of conflicts.

In both the areawide and focusing approaches, potential bidders are asked to outline areas or tracts in the planning area, which they believe to have hydrocarbon potential and in which they might be interested in leasing. When the Call depicts an area of hydrocarbon potential within the Call area, respondents may indicate interest within or beyond it. All interested parties are requested to comment on possible environmental effects and use conflicts. The scope of the information obtained by MMS ranges from broad area information to tract-specific information. In the focusing approach, other information may be solicited in a more precise form. For example, information from potential bidders has been requested on areas which had been deleted in past sales in the same area. The Area Identification step is a formal decision on the area whose offering is analyzed as the proposed Federal action in the EIS. This step roughly corresponds to the tract selection step. The information received from the Call, along with other information, is used to decide what areas, if any, should be deferred from further consideration at that point.

MMS uses the responses from potential bidders to identify promising areas, taking into account the collective judgment of the oil and gas industry as well as its own. In the case of the initial areawide approach, MMS added to that promising acreage other acreage which was not nominated which filled out a broad area outline. The focusing approach, in part, concentrates more on geological basins as identified by MMS and industry responses to the Call, omitting areas where MMS sees no hydrocarbon potential. The focusing approach also aims at the early resolution of problems or conflicts that have been identified. For example, 61.2 million acres were deferred in the Area Identification decision for Sale 111, Mid-Atlantic.

-The Size Range of Areas Selected, Identified, Offered, and Leased

--Examples

The following statistics are provided to illustrate the range of the size of the area identified as the proposed Federal action, the area offered, and the area leased under each presale approach.

Under the tract selection approach, the acreage selected in the tract selection step ranged from about 400,000 acres to about 3 million acres. The acreage offered had about the same range. The area leased ranged from about 300,000 acres to about twice that amount.

The largest area identified under the initial areawide process was in Sale 79, Eastern Gulf of Mexico (about 58 million acres) while the smallest was in Sale 76, Mid-Atlantic (about 25.4 million acres). The areas eventually offered by those sales were 50,632,000 and 22,671,000 acres, respectively. The area leased in the first sale was 898,000 acres (one and one-half percent of the Area Identification acreage) and in the second, 211,000 acres (eight-tenths of one percent of the Area Identification acreage).

Reflecting decisions made under the modified areawide approach, the smallest modified areawide proposal (Sale 92, North Aleutian Basin) identified 5.7 million acres (about 17 percent of the planning area). The largest modified areawide proposal (Sale 94, Eastern Gulf of Mexico) identified 50.8 million acres. Whereas Sale 79 identified 100 percent of the Eastern Gulf of Mexico planning area, Sale 94 identified about 88 percent of that same planning area. It is illustrative of the flexibility of focusing on promising acreage that the decision on the proposed Notice of Sale for Sale 94 reduced its area from the over 50 million acres identified for study to about 37 million acres, based on coordination with affected States and other parties. Sale 94 resulted in leases for about three-tenths of a percent of the Area Identification acreage. The results of Sale 92 must await the resolution of ongoing litigation. Focusing on promising acreage may well be characterized by an even wider range. In the Central and Western Gulf of Mexico, DOI has been evaluating the possibility of restricting leasing to within 2,400 meters water depth. In the final Notice for Sale 98, Central Gulf of Mexico, and Sale 102, Western Gulf of Mexico, blocks in water depths greater than 2,400 meters were deleted from the sales. In Sale 102, however, four blocks were leased which touch the 2,400 meter line and two were leased which are located 3 miles from the 2,400 meter line. Furthermore, in comments in response to the Call for the 1987 Gulf of Mexico sales, five companies expressed high or moderate interest in acreage deeper than 2,400 meters. For those 1987 sales (Sale 110, Central Gulf of

Mexico and the 1987 Western Gulf of Mexico Sale 112), the 2,400 meter line was not imposed as a limit at the area identification stage. The Area Identifications for those sales covered about 31.3 million acres and 27.1 million acres, respectively.

--Limits on Projections

Examples like those given above are illustrative of the different presale processes. Projections of future outcomes, however, cannot be performed with great precision because the "presale process" is an abstraction whose concrete implementation can lead to very different results in different planning areas. The results of the presale process are likely to differ both as between planning areas and as between sales in the same planning area because they depend on the following variable factors: (1) MMS and industry estimates of the amount and distribution of undiscovered oil and gas resources remaining in an area; (2) environmental and multiple-use considerations; and (3) the results of consultations with numerous parties, including coastal State Governors, under section 19 of the OCS Lands Act. All three factors are subject to different perceptions by the various parties who participate in the offshore leasing process. The third factor, depending as it does on a consultation process, does not lend itself to reliable predictions.

For example, the implications for sale size of multiple-use considerations such as the location of Department of Defense (DOD) use areas are subject to change based on consultation. In addition, different local attitudes toward oil and gas leasing and other uses of the ocean can lead to very different outcomes of consultations between the Department of the Interior and other parties such as coastal State Governors under section 19 of the OCS Lands Act. Both the Gulf of Mexico and Pacific regions contain significant deposits of commercially recoverable hydrocarbons under nearshore waters. The large size of Gulf of Mexico areawide sales and the small size of, for example, Sale 80, Southern California (657 tracts), clearly illustrate the effect of factors whose implications for the size of a lease sale are not clearly predictable.

Furthermore, in considering the precision with which "leasing activity" can be planned under section 18(a) of the OCS Lands Act, it is also important to keep in mind the wide gap between offering tracts and leasing them. In the Mid-Atlantic Sale 76, over 22 million acres were offered, but under 1 percent of that area was leased. In the Eastern Gulf of Mexico Sale 79, over 50 million acres were offered, but less than 2 percent of that area was leased. Even in the OCS sale which leased the largest number of tracts (Sale 72, Central Gulf of Mexico), the 623 tracts leased represented just over 8 percent of the acreage offered. Additional examples appear in Appendix O. Among the numerous factors which influence the number of tracts actually leased are the state of the economy, future oil price expectations, individual company strategies, and exploration results in the planning area and in other planning areas. These variables add to the uncertainty in planning the size of leasing activity.

-Planning and Coordination with States and Local Governments

Experience with areawide and focusing as well as tract selection sales held to date indicates that in all areas of the OCS, States are able to identify the parts of the proposed sale areas--down to specific blocks--which are of greatest concern to them for environmental or economic reasons. Nonetheless, several State and local governments indicated at various stages of the development of the new program that the Federal Government's--and their own--ability to analyze the effects of and coordinate with other governments concerning the offering of broad areas are strained and exceeded as the size of those areas expands (see especially Appendix B of the Proposed Program SID).

In its report entitled "Early Assessment of Interior's Area-Wide Program for Leasing Offshore Lands," the GAO summarized the results of a survey of oil and gas companies, coastal States and national environmental and fishery groups. The GAO concluded that most regarded Interior's planning documents for presale decisions as accurate and complete. Furthermore, most of those questioned believed that the time for review and comments was adequate.

-Multiple-Use Conflicts and Environmental Considerations

The offering of broad areas under the areawide leasing approach heightened the relevance of multiple-use issues. Multiple-use of the OCS is the subject of numerous comments summarized in Appendix B. Multiple-use and environmental considerations are treated generally in Appendices G and H and will be treated more fully in the EIS.

The presale process presents opportunities to receive information on and conduct consultations concerning multiple-use and environmental considerations. Decisions on the size of the Call area and the Area Identification provide the occasion for the early resolution of conflicts over these issues. The focusing approach emphasizes the use of these early decision points to resolve such conflicts that cannot be mitigated through other means--especially with respect to low-resource, low-interest blocks.

During the presale process, MMS coordinates with numerous parties who use the OCS, for example, the Coast Guard, the Navy, and the Air Force. For example, in response to Navy concerns about conflicts in Warning Area 155, a deferral of about 1.4 million acres was made from Sale 94, Eastern Gulf of Mexico. To mitigate operational conflicts with the Navy further, a stipulation has been developed for Warning Area 174 in the southern part of the planning area to restrict spacing of structures during exploratory drilling to allow unimpeded Navy carrier training exercises.

To mitigate use conflicts with Air Force operations in the Eglin Water Test Area in the Eastern Gulf of Mexico, a "time-sharing" stipulation has been developed which sets forth restrictions creating limited, phased access for exploratory drilling. Several "information to lessees" clauses also alert bidders to special concerns regarding other defense-related operations. The EIS under both the areawide and focusing approaches reviews deferral options as well as measures (such as stipulations) to mitigate potential adverse effects of development on a site-specific basis.

Appendix O documents presale deferrals from sales in the current 5-year program.

-Effects on Exploration of the Different Presale Processes

Section 102(9) of the OCS Lands Act Amendments provides that one of the purposes of that act is to "insure that the extent of oil and natural gas resources of the Outer Continental Shelf is assessed at the earliest practicable time." One objective sought when areawide leasing was adopted in 1982 was to expand the amount and location of acreage leased and thus to allow an increase in the rate of investment in exploration. Thus, it is appropriate to consider the effect of the different presale approaches on future exploration of the OCS.

In the Central and Western Gulf of Mexico, lease issuance proceeded under the tract selection procedures at a rate of about 1 million acres per year during the late 1970s and early 1980s. Almost twice as much acreage was offered--about 1.7 million acres per year--as was leased during that same period. Despite the nomination and tract selection process, only half of the acreage selected as promising 20-some months prior to each sale proved worth bidding upon after further evaluation by firms. Areawide leasing expanded the acreage offered in the Gulf of Mexico by a factor of 35. Acreage leased expanded from 1 million acres per year to about 5 million acres per year in 1983-1984. This shows a very substantial increase in the amount of acreage evaluated, bid upon, and acquired by offshore lessees.

The comparison of postlease exploration activity suggests that areawide leasing has had a favorable effect on investment in exploratory drilling. Although leases resulting from areawide Sales 72 and 74 have been in existence only a short time, drilling activity, based on the number of leases drilled, seems to be proceeding at a higher rate than it did as a result of previous tract selection sales (see Appendix P). The GAO report on areawide leasing also examined the effects on exploration. It concluded that "exploration is progressing at a faster rate under the area-wide program." This report includes data showing that more tracts had been drilled from Gulf of Mexico areawide Sales 72 and 74 than from any recent tract selection sales. In addition, a majority of oil and gas companies responding to GAO's questionnaire said that areawide leasing would facilitate exploration and that they have greatly increased their exploration in the Gulf of Mexico as a result.

The areawide approach maximizes the industry's ability to utilize the most up-to-date exploration data and interpretations providing greater flexibility to bid on areas that were of little interest 2 to 3 years prior to the sale, when the Call would have been issued. The areawide approach thus allows the incorporation of late-developing exploration data into both government and industry presale planning more than was the case with the tract selection approach.

Table 18

Producing or Producible Leased Tracts Containing Surface Area Leased More Than Once

| Area | Sale | Number of Producing or Producible Leased Tracts Previously Leased |
|---|---|---|
| Gulf of Mexico (GOM) | 84 | 3 |
| | 81 | 10 |
| | 74 | 16 |
| | 72 | 44 |
| | 69 Part II | 2 |
| | 69 Part I | 9 |
| | 67 | 10 |
| | 66 | 11 |
| | A66 | 24 |
| | 62 | 3 |
| | A62 | 21 |
| | 58A | 16 |
| | 58 | 13 |
| | 51 | 16 |
| | Pre-51 | 73 |
| | GOM Total | 271 |
| Pacific | 80 | None to date |
| | 68 | 1 |
| | 48 | 1 |
| | Pacific Total | 2 |

Under focusing on promising acreage, the early resolution of conflicts regarding acreage deemed to be low-value and low-interest can result in the exclusion of acreage about which potential bidders could change their opinion by the time of the sale. For example, in areawide Sale 79, Eastern Gulf of Mexico, a small number of blocks received bids in what had been identified as a low-value, low-interest area.

It is also worth noting that in areawide sales, blocks that had been previously leased and relinquished were again leased (see Table 18). Some were never tested, some were explored but the amount of hydrocarbons discovered was not economical to produce at that time, and others were produced but had not been drilled to horizons now considered prospective. A tract selection approach may not ensure the reoffering of such blocks as soon as under the focusing or areawide approaches.

While areawide leasing substantially increased the acreage leased and the rate of investment in exploration, continuation of areawide leasing in the 1987-1992 period may not result in leasing and exploration at the rates achieved in the 1983-1985 period. As Appendix P describes, the substantial increases in areas leased that resulted from early areawide sales reflected leasing from an unleased inventory of attractive prospects for drilling that had been built up by the combination of price increases and the smaller offerings under the tract selection procedures in the 1976-1982 period. The substantial amount of leasing that will have occurred in the 1983-1987 period, coupled with substantial decreases in oil price expectations, could leave an unleased inventory with far fewer attractive prospects for the 1987-1992 period. Even with these changed conditions, providing industry with a wider range of choices through a form of areawide leasing could still lead to the testing of more diverse exploration strategies than under a tract selection approach.

-Flexibility

The areawide approaches allow more flexibility to increase rapidly the amount of acreage offered if oil prices increase rapidly again. This could be particularly true if the administrative processes for restricted sales were to be accompanied by reduced administrative capacity (budget and manpower), placing constraints on increases in the acreage to be offered.

The tract selection procedures of the 1970s made it difficult to increase the acreage offered when conditions warranted. The leasing experience of the 1970s shows that the longer the restriction in the availability of prospective acreage, the greater is the buildup of demand for investment and the greater the potential jump in the rate of investment when acreage is finally made available. The rapid increases in seismic evaluation, acreage leased, and exploratory drilling in 1983 and 1984 could have been smoothed out over 5 or 6 years had more acreage been made available starting in 1977 or 1978.

In summary, the investment consequences of differences in the pace of lease offerings will tend to be greater the more rapid and extensive are the changes in oil price expectations and geological knowledge. Restricted offerings tend to perform adequately in a relatively stable world while wider offerings allow more flexibility for investments to adapt to changing conditions.

-Effects of Different Rates of Leasing on Bidding and Revenues

As described in Appendix P, the rates of leasing that result from different presale procedures can affect statistics such as the average bid per acre and the average number of bids per tract. For example, the average number of bids per tract may be less in large sales than in small sales. The MMS tract evaluation and bid adequacy procedures tend to focus on tracts with fewer bids in order to provide added assurances for achieving fair market value. The analysis also shows, however, that both the level of competition and the amounts bid are strongly influenced by the economic value of the inventory of tracts offered for sale.

The set of tracts offered depends upon the size of the sale and nature of acreage remaining to be leased after previous sales. Thus, if relatively little acreage has been offered while tracts appreciated in value, the value of tracts offered could generally increase. Similarly, large sales would tend to offer many more modest and low value tracts along with the high value prospects that would tend to be offered in smaller sales. Average bid statistics reflect these differences, with bids declining as areawide and focused sales proceeded, particularly in the Gulf of Mexico where a sizable unleased inventory of attractive prospects had accumulated. Declines in the average bid due to such effects are not indicative of failure to meet the fair market value requirement.

Changes in economic conditions and the physical or geological characteristics of the tracts leased can also occur over a period of leasing. If such changes generally reduce the economic value of the tracts offered in subsequent sales, average bids will decline. The decreases in oil price expectations since 1982 and the trend toward leasing more tracts in deeper water having smaller prospects or in higher cost areas contributed to the decline in average bids evident in the 1982-1984 period. Again, declines caused by such changes in the economic value of the tracts offered and bid upon are not indicative of a failure to satisfy the fair market value requirement.

The GAO report on areawide leasing includes a statistical analysis of competition and bonus revenues under tract selection and areawide leasing. It concludes that the average number of bids declined from 2.55 per tract in tract selection sales to 1.65 in the areawide sales it reviewed. It also finds that the tract selection sales between November 30, 1979, and April 25, 1983, had an average bonus of $2,624 per acre whereas the areawide sales between April 25, 1983, and September 30, 1984, had an average bonus of $686 per acre. Of the $1,738 per acre difference, the GAO estimated that $541 was caused by the shift to areawide leasing while $1,397 was due to other factors. On this basis the GAO estimated that the Federal Government received $5.4 billion (discounted to 1984) less for the tracts leased in the first ten areawide sales than it would have received if the same acreage had been leased using tract selection sale procedures. The GAO report notes that the OCS Lands Act "does not require Interior to maximize government revenues for offshore leases," though revenues are an important consideration. The GAO observes that under tract selection, industry "paid a premium" which it "has been less willing to pay" under areawide leasing. It also acknowledges that "some of the estimated reduction in bonus revenue due to the increased pace of areawide leasing will be offset by earlier receipt of royalties, rents and taxes which continue for many years after a tract is placed in production." The GAO analysis has been reviewed by MMS, as set forth in the letter to the Congressman Jack Brooks, Chairman of the Committee on Government Operations of the House of Representatives, signed by

MMS Director Bettenberg on September 30, 1985, which is included in the SID by reference.

Appendix P provides more recent data on leasing and exploration, and reports preliminary efforts to estimate the effects of earlier receipt of non-bonus revenues. It identifies a number of deficiencies in the statistical analysis which seriously undermine confidence in the GAO's estimate of the bonus reductions caused by areawide leasing. While many of these deficiencies are highly technical, the difficulty of isolating the bonus effects of areawide leasing from the effects of other factors can be gauged from the difficulty in measuring some of these other factors. For example, bidders' expectations about future oil and gas prices have been changing substantially during the 1979-1985 period. It is unlikely that such changes in bidders' expectations are accurately measured by forecasts of future prices by MMS or any other individual forecaster.

Similarly, it is unlikely that measures of the resource potential of the tracts leased accurately reflect the variations in individual bidders assessments of the resources, given the mixed results of exploration in recent years. Changes in firms' optimism about the prospects for new discoveries would clearly affect their bids (and the level of competition) but are difficult to measure for purposes of a statistical analysis.

Appendix P summarizes preliminary analyses by MMS of the overall revenue effects of earlier leasing and shows the substantial gains to the Treasury that can be realized. The leasing in the Gulf of Mexico is the best example of such effects. In 1983 and 1984, 1,029 tracts were leased in the Gulf of Mexico under the areawide and promising acreage approaches. Had these same tracts been leased under the tract selection approach, which typically leased 200 tracts per year, it would have taken about 12 years to complete their leasing. All of the revenues--bonuses, rents, royalties, and taxes--paid as a result of these leases occur earlier (except, of course, the revenues fromm the 200 tracts that would have been leased in 1983 under tract selection). In fact, revenues from the last 200 tracts leased in 1985 have been moved up by about 9 years. Appendix P shows that, because of these gains to the Treasury, areawide leasing could have reduced bonuses by as much as $8.5 million per tract without causing an overall loss.

Furthermore, leasing and search for oil and gas is a sequential process in which new prospects are identified each year using the results of exploration from previous years. Tract selection leasing would have limited the rate at which industry searched through the many prospects made attractive by the price increases of the 1970's. Areawide leasing in the 1983-1985 period has made it possible to advance the exploration of all resources that are currently economical by as much as 9 years. Further advances will be realized for as long as the areawide leasing and exploration rates exceed those that would have resulted from tract selection leasing. These advances in the timing of the development of all currently economical resources yield gains in increased economic benefits. It is difficult to specify with much certainty the economic conditions and resource development over the next four decades, even in the Gulf of Mexico. However, under reasonable assumptions, it appears that advances in development under areawide leasing could yield gains of $8 to $12 billion in the present value of oil and gas realized from resources yet to be leased in the Gulf of Mexico.

Discussion of Options for Focusing on Promising Acreage

These options derive from consideration by Interior of public responses to questions posed in the Federal Register Notice announcing the Proposed Program. Parties recommending these options are indicated within brackets.

(A) Larger offerings in the Gulf of Mexico, smaller offerings in most other areas.

(B) Delay deferrals until after the sale-specific draft EIS [Mobil, NOIA]

(C) Revise nomination procedures so as to request more detailed information from industry on areas of interest prior to the issuance of the Call (to be displayed in the Call) and again after the issuance of the draft EIS [Massachusetts]; but do not require additional proprietary data or, if required, exempt it from release [Murphy Oil USA, API, NOIA, Conoco].

(D) Revise nomination procedures so as:

(I) to request more detailed information concerning "negative nominations" [API]; and

(II) to develop minimum criteria for the consideration of deferral requests [Phillips, WOGA].

(E) A sale-by-sale decision on whether to publish a pre-Call notice in the Federal Register soliciting industry comments on whether there should be any deferral of leasing based on resource potential or interest in portions of the planning area or any delay of the sale, provided that any proprietary information will be held confidential by the MMS throughout the 5-year period covered by the new program [Tenneco; Conoco--for application to frontier areas].

(F) Flexible Call for Information: identify a relatively narrow Call area; accept acreage nominations outside of the Call area, if any, and include that acreage at the Area Identification stage; request public comments on any acreage nominated outside the original Call area, and require that comments opposed to the addition of such additional acreage be accompanied by adequate scientific justification; consider all relevant scientific evidence during the preparation of the EIS along with a proper assessment of the benefits of leasing that acreage.

(G) Highlight on a map issued with the Call the MMS interpretation of the promising acreage area within the Call area. The text of the Call would explain that while primary consideration would be given to the highlighted area, respondents may nominate any acreage within the Call area. Comments would be requested within the entire Call area. Such nominations and comments would be considered at the Area Identification stage for identification of the proposal to be analyzed in the EIS.

Option A attempts to provide a general characterization of focusing on promising acreage in terms of possible set of results: larger offerings in the Gulf of Mexico; smaller offerings in most other areas. Gulf of Mexico sales tend to be relatively large (i.e., offering for lease a high percentage of the planning area and thus a large amount of acreage as contrasted to tract selection sales) because of the areal dispersion of oil and gas deposits there and the continual flow of new data from ongoing oil and gas activities. The latter provides a basis for larger sales because it explains why areas of interest cannot be narrowed down early in the presale process. The two years between the Call and the sale provide new information which can cause bidders to lose bidding interest in some areas and develop it in others.

While the Southern California and Beaufort planning areas have continuing exploration programs, their pace is not nearly as great as that in the Gulf of Mexico. Furthermore, the rapid increase in water depth off the West Coast limits the areal extent of leasing activity there. In the Arctic, harsh operating conditions tend to limit potential sale size. In other planning areas, the absence of an ongoing exploration program makes the identification of areas in the early stages of the presale process less prone to obsolescence. Therefore, narrowing the sale to a more limited area early in the process could be appropriate. No arbitrary limit on sale size need be set. Such a limit could result in an opportunity cost to the Nation caused by ignoring unique exploration theories. Option A, however, also needs to be considered in the context of the equitable sharing requirement of the OCS Lands Act (see Part II. C, above).

Option B would delay deferrals until after the sale-specific draft EIS. This would constitute a change in the thrust of the timing of focusing on promising acreage, which seeks resolution of conflicts earlier in the process.

Options C, E, and F propose to narrow the Call area within the planning area. Option C would do this for all sales, by means of a pre-Call solicitation of industry interest in greater detail than at present. Such greater detail could be provided by means of soliciting industry geological and geophysical data and/or analyses in support of nominations. Option C also provides for a second round of nominations after the draft EIS. Such a procedure could help establish whether areas where environmental concerns have been identified continue to be of interest to industry. These elements of Option C are based on a recommendations from Massachusetts. The final element of Option C--concerning the protection of proprietary data--derives from industry responses to the request for comments on Massachusetts' recommendation (highlighted for comments in the Federal Register Notice announcing the Proposed Program) that MMS solicit more detailed information from industry concerning areas of interest. (One possible means for soliciting interest prior to the Call is discussed under Option E. The discussion there relative to the issuance of a formal public notice also applies to the solicitation of information after the draft EIS.)

Option E would provide for pre-Call interest solicitation as a possibility for any sale, to be decided on a case-by-case basis. Option E also proposes that a public announcement be issued for this process. Issuance of a public notice can help ensure that all potentially interested parties--and, in particular, the authoritative sources for a response within an organization--have been reached.

Option F would narrow the Call area based on the MMS interpretation of the most promising acreage and industry submissions for the preceding sale in the area. The industry parties who recommended Option F anticipated that "in most planning areas, industry and MMS assessment of promising acreage will include a relatively small percentage of total size of the planning area." However, industry would be able to nominate areas beyond the Call which could be added to the area under consideration at Area Identification and announced to the public for comment. Presumably, any area nominated beyond the Call area could be considered in the draft EIS as an alternative which could be selected in addition to the Call area analyzed in the draft EIS proposal. Public comments on these additional areas would then be solicited during the public review of the draft EIS.

In order to maintain the pyramidic character of the presale process and minimize changes in the sale proposal between the draft EIS and final EIS (and the associated potential for delay in holding the sale), Option G proposes a modification of Option F, as follows: highlight within the Call area the MMS interpretation of the promising acreage area. If additional areas beyond the highlighted area were nominated, they could be considered for inclusion in the Area Identification--without having to add further public review to get public comments on the additional areas.

Options D and F propose that stricter requirements be developed for the consideration of "negative nominations:" that they be accompanied by more detailed information (D-I); by "adequate scientific justification" (F); and that Interior develop minimum criteria for consideration of such requests (D-II). While Interior can solicit detailed scientific information, public comments cannot be excluded because such information is not provided. It should also be noted that scientific information for use in DOI decisions is pursued throughout sale-specific documents by DOI's scientific staff (as advised by the Scientific Committee of the OCS Advisory Board) and through public comments on sale-specific documents, including EISs.

Comments on the Presale Process

° State Governors: Maine, New Hampshire, Massachusetts, Rhode Island, Delaware, Maryland, Virginia, North Carolina, and Florida expressed a general endorsement of the concept of focusing on promising acreage. Maine, Massachusetts, New Jersey and North Carolina recommended that nomination procedures be revised to request more detailed information from industry on areas of interest prior to issuance of the Call for Information and Nominations and again after issuance of the draft environmental impact statement. Maine stated that there is no basis for requesting more detailed negative nomination information and there is no need to require publication of a proposed Call area in the Federal Register. Connecticut suggested that a tract selection presale process be applied to areas within 50 miles of the coast. Delaware requested clarification of the proposed presale process and stressed the importance of making pertinent information available to States. Maryland expressed concern over the reliability of data at the Area Identification stage of the proposed presale process and urged close coordination with States when implementing the process. Florida commented that promising acreage should be delineated as early as possible in the presale process, so that analyses in the EIS can focus on those promising areas to be offered. Mississippi endorsed the concept of focusing on promising acreage. Alabama stated that the presale process should designate as a high potential subarea any portion of an OCS planning area where a major new hydrocarbon discovery is made, and maximum effort should be made to resolve conflicts concerning such a subarea. Louisiana expressed concern that, under the proposed presale process, larger and larger sales will take place in the Central and Western Gulf of Mexico planning areas as oil prices rebound. They also requested that the 5-year program define promising acreage in the Central and Western Gulf in an effort to reduce environmental impacts. Texas recommended adopting a tract selection presale process, stating that increases in the pace of development can be achieved without imposing the high costs and low returns to Federal and State Governments which are associated with areawide leasing. California generally endorsed the proposed presale process, but requested clarification of the following points: (1) the criteria that will be used to select blocks at the Call and Area Identification stages; (2) the type of information to be required for both positive and negative block nominations; and (3) the consultation and consensus procedures. With regard to the last point, they recommended that additional time be provided for States to solicit and address local government concerns. They also stated that it would be inappropriate to include blocks in the Area Identification stage if they were not included in the original Call area. Alaska recommended adopting a tract selection presale process and stated that if the focusing on promising acreage approach is adopted, blocks which receive no indication of industry interest should be eliminated from further consideration.

° State Agencies: New York Department of Environmental Conservation and Florida Department of Environmental Regulation endorsed the concept of focusing on promising acreage. Georgia Department of Natural Resources endorsed the concept of focusing on promising acreage but requested clarification concerning how areas would be studied and the process by which environmentally sensitive blocks would be identified. Texas General Land Office expressed opposition to the proposed presale process, stating that it would result in the offering of the entire Central and Western Gulf of Mexico planning areas, except for the Flower Garden Banks. California Coastal Commission commented that there is little difference between focusing on promising acreage and areawide leasing, and the size of lease sales will remain too large. California Department of Justice stated that the proposed presale process must be clarified so that it will be implemented consistently. Oregon Department of Geology and Mineral Industries stated that the proposed presale process should provide at least 90 days for review of the draft environmental impact statement (EIS).

° Local Governments: County of Volusia (FL) endorsed the concept of focusing on promising acreage and recommended that promising acreage be identified early in the presale process to eliminate conflicts. Ventura County (CA) endorsed the proposed presale process as preferable to areawide leasing. AMBAG (CA), San Luis Obispo County (CA), and City of San Diego (CA) commented that the proposed presale process does not precisely define the size of a sale and makes planning and environmental analysis extremely difficult. City of San Luis Obispo (CA) expressed opposition to areawide leasing and stated that focusing on promising acreage would be acceptable if there is adequate State and local consultation, the Governor's presale comment period is expanded to 90 days, and special consideration is given to specific subareas. City of Newport Beach (CA) stated that the proposed presale process will result in the leasing of blocks determined by oil company preference. City of Laguna Beach (CA) commented that local governments should be directly involved in the presale process to determine the size of sales. Several local governments in California commented on this topic by noting the proposed presale process in resolutions stating general opposition to the Proposed Program. These include Mendocino County, Monterey County, Orange County, San Luis Obispo County, San Mateo County, and Santa Cruz County. North Slope Borough (AK) expressed support for the proposal to request more detailed information from industry on areas of interest prior to the Call for Information and Nominations and again after issuance of the draft EIS.

° Federal Agencies: DOD and NOAA endorsed the concept of focusing on promising acreage. EPA expressed support for the proposed presale process but requested clarification of it. They also recommended that focusing be done at the area identification stage so that environmental analysis can concentrate on a smaller area.

° Industry: The majority of commenters addressing this topic stated a general preference for areawide leasing and perceived focusing on promising acreage as a process which would limit exploration strategies and opportunities. API, Exxon, and Combustion Engineering urged that areawide leasing be retained in the Central and Western Gulf of Mexico planning areas. Unocal expressed support for areawide leasing in the Gulf of Mexico and Alaska OCS planning areas. AOGA, NOIA, Chevron, Conoco, Exxon, Texaco, and Zapata expressed general support for focusing on promising acreage. API, NOIA, and Exxon recommended that the proposed presale process incorporate the following provisions: encouragement of diverse, innovative approaches to leasing and development; prohibition of subarea deferrals without valid scientific or legal justification; consideration of previously deferred subareas as appropriate; identification of the Call area as only a guideline for the information request; and consideration of expressions of interest in areas outside of the Call area guideline. API also suggested that MMS rely to a great extent on the petroleum industry to determine the most promising acreage for each sale. Exxon recommended that the proposed presale process employ a "flexible call for information" which would allow nominations outside a narrow initial Call area. They stated that such a concept would provide for consideration of all exploration theories while focusing necessary environmental and economic analyses on a relatively small sale area. They also recommended that only a brief supplemental environmental impact statement be prepared for sales offering blocks which previously have been analyzed and offered. BP Alaska, Standard, and AOGA recommended that industry be given the opportunity to request expansion of the proposed sale area as part of the Call process. Shell expressed opposition to focusing on promising acreage prior to the Call for Information and Nominations step for each lease sale. Commenters addressing this topic were unanimous in opposition to revising nomination procedures to request more detailed information from industry on areas of interest prior to the issuance of the Call and again after issuance of the draft EIS. Many cited their concerns about disclosure of proprietary data as the principal reason for objecting to the proposal. The great majority of commenters addressing this topic endorsed the recommendation that nomination procedures be revised to request more detailed information concerning negative nominations. Several recommended that negative nominations be required to be submitted without prior knowledge of the most recent expressions of industry interest. Amoco expressed skepticism concerning the proposal to revise negative nomination procedures, stating it would result in discounting unique company perceptions and strategies. The great majority of commenters addressing this topic expressed opposition to announcing in the *Federal Register* the availability of the MMS proposed Call area for industry interest review prior to the issuance of the Call. Conoco endorsed the proposed *Federal Register* announcement of the Call area for industry interest review. Exxon and Tenneco expressed qualified support for the proposed *Federal Register* announcement of the Call area for industry interest review. Exxon recommended that the procedure be adopted informally on a sale-by-sale basis and information on company interest be withheld from public release prior to the Call for Information and Nominations.

Tenneco recommended that industry interest information be withheld from public release for at least the term of the 5-year leasing program.

° Environmental and Other Organizations: NRDC recommended the use of a tract selection process because the areawide and focused approaches cause adverse economic impacts and are unpredictable and unsatisfactory for planning purposes. Maine Audubon Society requested clarification of the proposed presale process, stating that it is not clear if focusing on promising acreage will select tract sizes that are large enough to be economically viable yet small enough to be adequately assessed for environmental impact. Association for the Preservation of Cape Cod, Inc. stated that focused leasing is not very different from areawide leasing, which they oppose. Massachusetts Audubon Society expressed opposition to the proposed presale process, stating that it does not reduce the scale of lease sales enough to allow adequate assessment of environmental impacts. Friends of Canaveral (FL) recommended that lease sales focus on areas with greater resource potential to facilitate planning. Florida PIRG endorsed the concept of focusing on promising acreage, but requested clarification. They made the following specific recommendations concerning the process: (1) improve identification of areas of high industry interest so that a greater percentage of the area offered is actually leased; (2) consider areas of high environmental concern for deferral; and (3) define deferral areas before developing the EIS, and tailor the EIS to the focused area. Manasota 88 (FL) commented that the process of focusing on promising acreage appears to be without logic, since sale 94 in the Eastern Gulf of Mexico offered about 36 million acres, while the Call for Information and Nominations for Sale 91 in the Northern California planning area included only about 1.2 million acres. League of Women Voters of Ventura (CA) commented that the proposed presale process would not result in sales of reasonable size to decrease impacts and allow onshore infrastructure to keep pace with offshore development. League of Women Voters of Santa Barbara (CA) commented that no matter what presale process is employed, the result will be rapid offshore and onshore development in the Santa Barbara area. Sierra Club (Santa Lucia, Ca Chapter) commented that the proposed presale process would result in lease sale areas which are too large. Salinas (CA) Chamber of Commerce expressed opposition to areawide leasing.

° Private Citizens: Several commenters stated that the Proposed Program would feature sales offering areas which are too large.

## III.C. Minimum Bid and Bid Adequacy Review Options for the Proposed Final Program

Section 18(a)(4) of the OCSLA requires the formulation of an OCS leasing program consistent with the principle that, "leasing activities shall be conducted to assure receipt of fair market value for the lands leased and the rights conveyed by the Federal Government."

As discussed in SID Section II.E. and Appendix K, the development of the existing 5-year leasing program included substantial revisions to the policies and procedures for meeting this requirement. The 1982 5-year program document was challenged in court on the grounds that areawide leasing would reduce competition and reduce lease bonuses and that the revised policies and procedures for deciding whether to accept or reject high bids represented an abandonment of previous tract evaluation procedures. The court, in California v. Watt (II), rejected this challenge, finding that it was reasonable for the Secretary to combine reliance on the competitive bidding process with the proposed tract evaluation and bid rejection procedures in order to meet the fair market value requirement.

In 1984 and 1985, modifications were made to the OCS bid adequacy procedures to incorporate knowledge gained from their actual use in areawide lease sales. In addition, the Department is continuing to evaluate the consequences of areawide and more focused leasing to determine their effects on revenue receipts and cash bonuses bid for tracts. This anlysis is summarized in Appendix P.

The current bid adequacy procedures are described in detail in Appendix K. Where appropriate, the procedures continue to rely on competitive market forces to assure the receipt of fair market value. However, tracts which fall into certain identified categories are subjected to additional independent Government analysis to assure that the high bids received adquately reflect the fair market value. The minimum bid is currently set at $150 per acre with an opportunity for review on a sale-by-sale basis.

The MMS conducts evaluations of these procedures independently of this leasing program formulation. However, in developing the new 5-year leasing program, there is an opportunity to review the current procedures, evaluate their performance in conjunction with decisions about the size and timing of lease sales, and consider means for continuing to assure that fair market value will be received.

MMS is currently reviewing the minimum bid policy as part of an analysis of possible measures to stimulate offshore oil and gas leasing, exploration, and production. A request for comments on several policy questions related to this subject was published in the October 31, 1986, Federal Register. In conjunction with this analysis of potential leasing incentives, the MMS developed some options for consideration for the Central Gulf of Mexico Sale 110. These options included developing an appropriate combination of minimum bids and rental schedules to encourage leasing while also providing incentives for early exploration in this period of low oil prices. These options were evaluated in the decision on the Final Notice of Sale for Sale 110.

The $150 per acre minimum bid requirement has provided an important supplement to bid adequacy procedures and has contributed to increases in aggregate bonus revenues, especially in proven areas of the Gulf of Mexico. However, higher minimum bid levels can adversely influence the level of interest for tracts in frontier areas, and hence may substantially reduce the number of tracts receiving bids in frontier area sales. Under current economic conditions, it would appear that lower minimum bids in frontier areas may enhance current leasing interest and potentially provide important information about the hydrocarbon prospects of the areas without jeopardizing receipt of fair market value.

The minimum bid level is an important policy tool which can be tailored for specific planning areas to encourage efficient exploration and development of OCS oil and gas resources. From the standpoint of economic efficiency, a tract should be leased today when its economic value as developed today is greater than if developed in all future periods. Conversely, leasing of tracts should be delayed if the economic value is higher if developed in some future period. Because oil and gas are exhaustible resources, their real value tends to rise over time. This means that the leasing and subsequent development scenario which is best for the Nation may involve a delay in the sale of certain high cost prospects in a planning area even while investments are proceeding on lower cost prospects. Absent some mechanism to prevent the leasing of certain high cost prospects, tracts with positive private value could be leased and subsequently developed too soon, partly because of deiligence requirements. Accordingly, it would be desirable to retain these prospects in the Government's inventory until the time when their sale would produce maximum net benefits to the Nation. The minimum bid policy level can be employed to filter out tracts which, according to MMS estimates, may be better retained until a later time. Under the current economic conditions, however, lowering the minimum bid level may not contribute to the leasing of tracts prematurely in sales held over the next few years in frontier areas. This result is expected because lower prices and price expectations are significantly reducing the private profit potential so that only the highest valued prospects could be expected to be leased even at a $25/acre minimum bid level.

Minimum bid policy is also a potentially important consideration for promoting exploration in high risk areas. Because the full public value of exploratory drilling is generally not reflected in private firms' assessment of tracts, there is a tendency for the private market to relatively undervalue and hence lease less acreage in frontier areas vis-a-vis proven areas. To account for these effects, it may be appropriate to consider lower minimum bids in selected high risk areas during the 5-Year Program.

Thus, while there may be some benefits to the Nation from restraining leasing on individual high cost prospects, it is also likely that some level of exploration is desirable in selected high risk areas of low industry interest. Therefore, there are compelling reasons for determining the appropriate size of the minimum bid on a sale-by-sale basis.

Two decision options have been developed for the Proposed Final Program which reflect the policy implications of minimum bid level and bid adequacy review procedures for the receipt of fair market value, economic efficiency, and for frontier exploration issues. The options presented for decision are as follows:

C.1. Minimum Bid Options:

a. Confirm the Proposed Program decision to maintain the $150/acre minimum bid as the basic approach and determine on a sale-by-sale basis what changes, if any, are to be made; and

b. Other

C.2. Bid Adequacy Review Options:

a. Confirm the proposed Program decision to maintain current bid adequacy review procedures as the basic approach and determine on a sale-by sale basis what changes, if any, are to be made;

b. Other

The selection of options C.1.a and C.2.a would maintain the current minimum bid policy and the current bid adequacy review procedures adopted in the Secretarial Issue Document of March 11, 1982 (and subsequent decisions) until changes, if any, were made for individual sales.

Since the minimum bid level has the property of influencing the amount and types of tracts (e.g., deepwater or shallow water tracts) which could be leased, a 5-Year Program decision on the approach to be used to determine the size of lease sales could be made in recognition of the possibility of varying the minimum bid. For example, as discussed above, the minimum bid can be used to delay the leasing of tracts which should remain in the Government's inventory. Thus, concerns raised in formulating the 5-Year Program about premature leasing (and to a limited extent fair market value), could be alleviated with an appropriately set, sale-specific, minimum bid.

Part IV. Other Issues

## A. The IRM Proposal for a Bering Sea Advisory Committee

The agreement facilitated by the Institute for Resource Management (IRM) contained, in addition to the subarea deferral recommendation discussed above, a proposal to establish a Bering Sea Advisory Committee (BSAC). The BSAC would be designed to study and make recommendations for the consideration of the Secretary of the Interior regarding specific stipulations to be included in Bering Sea leases.

This BSAC proposal does not call for a Secretarial decision because it applies directly only to activity of the parties to the IRM agreement and no federal funding would be involved. Indirectly, however, there are implications of this element of the IRM proposal which need to be considered.

In the words of the IRM agreement, the BSAC would

> ...be composed of a balanced panel of representatives from industry and from environmental, Alaskan Native and fishing interests. This committee would function as a forum for information sharing, problem solving and conflict resolution. Its goal is to expedite the existing process rather than to add another layer of bureaucracy or lengthy procedures.
>
> The BSAC would be responsible for identifying and making recommendations regarding appropriate biological monitoring activities and special studies to be conducted within specific areas of the Bering Sea. The BSAC would develop specific recommendations on stipulations for any lease sale including identification of highly sensitive tracts. These recommendations would be conveyed to the Secretary in a timely manner so that the Minerals Management Service may incorporate them in the lease sale. When more site specific information is available, the BSAC may provide additional recommendations to DOI on further stipulations for the exploration and production phase.
>
> In recognition of the important role of the Governor of Alaska in the OCS leasing process, the BSAC would keep the Governor informed of its recommendations:

The IRM proposal also provides that specific lease sale stipulations would be developed consistent with the following principles and guidelines.

> A. Oil Spill Clean-up Capacity
>
> The parties recognize that adverse weather conditions and ice floes may jeopardize oil operations and impose impediments to effective clean-up in case of an accident. It is agreed that stipulations for the Bering Sea should address these issues.
>
> B. Biological Data and Monitoring
>
> The parties recognize that though substantial data have been gathered, additional information may be required to provide for an effective biological baseline and for use as a basis for specific lease stipulations. It is agreed that the BSAC will make recommendations concerning the nature and timing of such studies.

C. Subsistence Values

The parties recognize that certain native groups sustain themselves from hunting, fishing, and trapping activities in the area. It is agreed that exploration, development and production operations shall be conducted so as to minimize conflicts with local subsistence activities.

D. Drilling Restrictions

The parties recognize that there are important sites of migration and breeding grounds, such as Unimak Pass and the Pribilof Islands, where drilling restrictions may be appropriate. It is agreed that the BSAC will provide recommendations on the specific geographic boundaries and dates of limitation or prohibition of activities.

E. Ice Monitoring

The parties recognize the potential problems for oil operation in areas of seasonal ice pack movement which may jeopardize the safety of operations. It is agreed that the BSAC will make recommendations regarding ice monitoring programs, where appropriate.

F. Costs and Timing

The parties recognize that some of the BSAC recommendations may cause operational delays and may increase costs of the exploration and development process. It is agreed that the BSAC will analyze these effects in developing its recommendations.

Discussion

-Consultation

On one hand, the proposed advisory committee could supplement the formal OCS consultation apparatus already in place. The signatories to the IRM agreement evidently see a need for such supplementation. The agreement which they reached in support of this proposal indicates the potential usefulness of this approach.

On the other hand, the BSAC would overlap with existing mechanisms for coordination and consultation. The existing OCS oil and gas program provides the opportunity for consultation and coordination with the oil industry, fishing industry, environmental groups, State and local governments, and Native Alaskan communities. The Secretary of the Interior receives both formal and informal input into the leasing process from the Call for Information and Nominations through the proposed Notice of Sale. Public input is solicited at the Call, at scoping meetings and public hearings on the sale-specific EIS, during review pursuant to the Alaska National Interest Lands Conservation Act (in light of court rulings), and during the Governor's review of the proposed Notice of Sale. Under sections 18 and 19 of the OCS Lands Act, the Governors of affected States are given the opportunity to provide comments to the Department on the 5-year program as well as individual lease sales. These comments represent the position of the State and often reflect input from public and private entities within the State. Most uniquely, the Governor's comments are given both special legal standing and particularly heavy weight under the terms of sections 18 and 19 of the OCS Lands Act.

Formal groups that now advise DOI on Bering Sea OCS leasing include the Bering Sea Biological Task Force (BTF) and the OCS Advisory Board with its Policy Committee, Scientific Committee, and Regional Technical Working Group (RTWG). These groups, whose members represent the Federal, State, and private sectors, have broad scientific, technical, and public policy expertise. In each individual committee, members work together to provide DOI with advice, reached by consensus, on specific leasing of exploration/production issues. Additionally, the Arctic Research and Policy Act provides coordination on Federal efforts on research.

The establishment of the BSAC would also overlap to some degree with the Oil/Fisheries Group already functioning through the sponsorship of the oil industry. In 1983, the Oil/Fisheries Group of Alaska was organized as an oil industry initiative with fisheries groups to help mitigate the adverse effects of offshore oil development on the commercial fishing industry. It consists of representatives from several major oil companies and the major fishing and processing organizations operating in Alaska. It provides a forum for interindustry communication, and resolution of potential problems by exchange of information on areas of high fishing-gear concentration, seasonal activity, and geophysical vessels and schedules.

-Considerations Concerning Stipulation Guidelines Proposed by IRM

The proposed guidelines overlap with requirements imposed on Alaska OCS Region lessees by the stipulations and Information to Lessees clauses typically used for Alaska OCS Region sales and MMS standard practices (see Appendix Q).

B. Proposals Concerning OCS Leasing Offshore California

The proposals concerning OCS leasing offshore California specified in P.L. 99-591 are examined in full in the final EIS and the California Analysis document.

# APPENDIX A

# LEGAL ASPECTS OF THE NEW PROGRAM

## LEGAL ASPECTS OF THE DEVELOPMENT OF THE NEW PROGRAM

### I. Discussion of Compliance with Section 18

Section 18 requires that the Secretary base his decision on the 5-year OCS Oil and Gas Leasing Program on the consideration of a number of factors. Judicial guidance as to how that requirement is to be carried out was provided by the U.S. Court of Appeals for the District of Columbia Circuit in California v. Watt (I) (668 F.2d 1290 (D.C. Cir. 1981)) and California v. Watt (II) (712 F.2d 584 (D.C. Cir. 1983)). The following discussion explains how the requirements of section 18 are being addressed in the decision material being provided to the Secretary. A note of caution is necessary in reviewing this material. While each aspect of section 18 is discussed individually, a judgment with respect to any one aspect cannot be made in isolation from the others. Most are interrelated and must be considered collectively.

1. 18(a)

a. Requirement

"The Secretary, pursuant to procedures set forth in subsections (c) and (d) of this section, shall prepare and periodically revise, and maintain an oil and gas leasing program to implement the policies of this Act. The leasing program shall consist of a schedule of proposed lease sales indicating, as precisely as possible, the size, timing, and location of leasing activity which he determines will best meet national energy needs for the five-year period following its approval or reapproval."

b. Compliance

The schedule options in Part III are described in terms of timing and location of leasing activity. The size of sales is treated separately under size options. All sale designations have been reviewed in order to conform with the court's guidance on the requirement that they be described "as precisely as possible" at the leasing program stage. The role of the leasing program in addressing national energy needs is discussed in Part II.A and B and Appendix F.

The schedule adopted by the Secretary as the Proposed Final Program will be described in the material transmitting it to the Congress and the President.

2. 18(a)(1)

a. Requirement

". . . [S]uch leasing program shall be prepared and maintained in a manner consistent with the following principles [18(a)]:



(1) Management of the Outer Continental Shelf shall be conducted in a manner which considers economic, social, and environmental values of the renewable and nonrenewable resources contained in the Outer Continental Shelf, and the potential impact of oil and gas exploration on other resource values of the Outer Continental Shelf and the marine, coastal, and human environments."

b. Compliance

The Environmental Impact Statement (EIS) on the new 5-year program discusses these values and the potential effects of oil and gas exploration, development, and production on them. In addition, the information considered for section 18(a)(2) and included in SID Part II and Appendicies F, G, H, and I addresses the values to which this subsection of the statute refers.

3. 18(a)(2)

a. Requirement

" . . . [S]uch leasing program shall be prepared and maintained in a manner consistent with the following principles [18(a)] . . . .

(2) Timing and location of exploration, development, and production of oil and gas among the oil- and gas-bearing physiographic regions of the Outer Continental Shelf shall be based on a consideration of--

(A) existing information concerning the geographical, geological, and ecological characteristics of such regions;

(B) an equitable sharing of developmental benefits and environmental risks among the various regions;

(C) the location of such regions with respect to, and the relative needs of, regional and national energy markets;

(D) the location of such regions with respect to other uses of the sea and seabed, including fisheries, navigation, existing or proposed sealanes, potential sites of deepwater ports, and other anticipated uses of the resources and space of the Outer Continental Shelf;

(E) the interest of potential oil and gas producers in the development of oil and gas resources as indicated by exploration or nomination;

(F) laws, goals, and policies of affected States which have been specifically identified by the Governors of such States as relevant matters for the Secretary's consideration;

(G) the relative environmental sensitivity and marine productivity of different areas of the Outer Continental Shelf; and

(H) relevant environmental and predictive information for different areas of the Outer Continental Shelf."

b. Compliance

Compliance with item (A) regarding existing information is reflected throughout the SID and appendices and addressed in particular in Appendices E, F, G, H, and I. It was addressed further in the EIS.

The framework for addressing Item (B), the consideration of equitable sharing of developmental benefits and environmental risks is discussed under Part II.C. This discussion draws upon the analysis of the estimated net economic value and the estimated social and regional costs associated with leasing in each planning area found in Part II.B and Appendices E, F, and G. The analysis of estimated social and regional costs addresses potential damage from oil spills including ecological damages, losses to tourism, recreation, commercial fishing, and clean-up costs. The analysis in turn, rests in part on the analysis of the relative marine productivity and environmental sensitivity of the different areas of the OCS and their respective adjacent coastlines. It also covers potential losses due to air pollution, commercial fishing conflicts and potential losses of habitats due to onshore support activities. Potential damages for which dollar cost estimates were not made are also identified for the Secretary's consideration. The analysis of relative marine productivity and environmental sensitivity in itself is also useful in considering these potential damages. Qualitative descriptions of the potential effects of leasing activity are included in the EIS.

Item (C), which includes consideration of the location of the regions relative to regional and national energy markets and their needs is addressed in a number of places. The Secretary's letter of February 4, 1986, to the Secretary of Energy specifically asked the Department of Energy to comment on this consideration, as well as on transportation networks. The Department of Energy provided information concerning these topics in a variety of its publications (State Energy Data Report Supplement 1960-1983, Petroleum Supply Annual, Petroleum Supply Monthly, Annual Energy Review 1985, Annual Energy Outlook 1985, and National Energy Policy Plan Projections to 2010 (1985)) and by means of staff contacts. Use was also made of the study, "The Export of Alaska Crude Oil: An Analysis of the Economic and National Security Benefits," prepared by Putnam, Hayes, and Bartlett, Inc., (May 1983). An analysis of availability of transportation to bring resources from various OCS areas to regional and national energy markets can be found in Appendix J. Further analysis of national energy considerations may be found in Part II.A and Appendix F. The social and regional costs related to various transportation systems are also considered in Part II.B and Appendix G, and are further analyzed in the EIS.

Item (D), concerning the location of planning areas with respect to other uses, is covered in Appendix H, which describes these other uses by planning area. Where possible conflicts exists, mitigation will be discussed in the EIS. The estimates of the social and regional costs developed for each area (see Part II.B and Appendix G) include the costs of the potential effects of OCS oil and gas activities on other uses of the sea and seabed, including commercial fishing and recreation. Other uses of the ocean are also considered in the analysis of subareas recommended for deferral from leasing.



Item (E), concerning the interest of potential oil and gas producers as indicated by exploration or nomination, is addressed in Part III and Appendices B and D. The interest expressed in each planning area was considered in determining the timing and location of sales. It is important to note that the relative interest of energy firms can differ from the relative ranking of areas based on MMS hydrocarbon estimates which appears in Appendix F. This is important because it provides information for selecting the timing and location of sales on factors in addition to MMS analyses.

Information regarding Item (F), laws, goals, and policies of affected States, can be found in Appendices B and C. This information has been reviewed to determine its implications for the planning of leasing activity. Appendix C also includes a table of approved coastal zone management plans. The EIS contains a characterization of each plan.

As the court held in California v. Watt (I), the Secretary need not delete an area from the schedule solely because some potential activity may be inconsistent with State policies. The information found in Appendix C may also be useful in assessing potential effects on the coastal zone as required by 18(a)(3).

Item (G) regarding relative environmental sensitivity and marine productivity is addressed in Part II.B.3 and in Appendix I. Professional judgments have been made of the relative environmental sensitivity and marine productivity of each OCS area and, in addition, of the adjacent coastal areas. These judgments were based on a detailed review of data on the environmental and marine resources in each area. Through its use in the social cost calculations, this analysis provides a partial basis for considering "an equitable sharing of developmental benefits and environmental risks among the various regions" 18(a)(2)(B) and the balancing of factors called for by 18(a)(3).

Estimates of social costs found in Part II.B and Appendix G are, to the extent possible, consistent with and reflect the information on and judgments about relative environmental sensitivity and marine productivity. However, many aspects of environmental sensitivity and marine productivity cannot be quantified in dollar terms. Thus, in addressing the 18(a)(3) requirement, the judgments made about relative environmental sensitivity and marine productivity should, therefore, be reviewed together with the EIS and the section on social and regional costs.

Item (H), concerning environmental and predictive information, is reflected in Part II.B and is treated further in Appendix H. It is also addressed in the EIS.

In reviewing the July 1982 program, the court validated the Secretary's consideration of items (B) and (G) in determining the location of leasing. These items, together with other 18(a)(2) items, are reviewed to determine if any planning areas warrant exclusion from the schedule.

In reviewing the timing of leasing in the July 1982 program, the court validated the Secretary's consideration of the environmental and coastal zone management elements of section 18. These factors are also considered in Part II.B, C, and D and Appendices B, C, G, H, and I. They also appear in the EIS.

4. 18(a)(3)

a. Requirement

"The Secretary shall select the timing and location of leasing, to the maximum extend practicable, so as to obtain a proper balance between the potential for environmental damage, the potential for discovery of oil and gas, and the potential for adverse impact on the coastal zone."

b. Compliance

This requirement is addressed in Part II.B, C, and D and Appendices E, F, G, H, and I. Those sections present information on social and regional costs, including environmental damage and adverse effects on the coastal zone, expected oil and gas resources, and net economic values by planning areas. This information is used to calculate the net social value of each area. Relevant qualitative factors not reflected in these calculations are assessed in Part II.B.3, Part II.C, and Appendices H and I and are also addressed in the EIS. These factors are reviewed together with the net social value calculations in formulating a leasing program.

The court in California v. Watt (II) endorsed the general interpretation of the balancing required by 18(a)(3) which was used in formulating the July 1982 program. This interpretation was that an area should be included if the benefits of leasing are expected to exceed the costs and that the most valuable areas should be offered first. The court also upheld the analysis of both section 18(a)(2) and 18(a)(3) factors which was performed on an area-by-area basis and a schedule-by-schedule basis.

Planning area analyses appear in Part II. Schedule-by-schedule comparisons appear in the form of the discussion of the cost of the delay of leasing in Part II.B and Appendix F, and in Part III (including the valuation of schedules summarized there and developed further in Appendix R).

The court also held that the damage from oil spills on fishing, tourism and other OCS-related enterprises must be quantified. This has been done in the calculation of social and regional costs for each area and is described in Part II.B.2 and Appendix G. The calculation of the net economic value of OCS oil and gas production is explained in Part II.B.1 and Appendix F.

5. 18(a)(4)

a. Requirement

"Leasing activities shall be conducted so to assure receipt of fair market value for the lands leased and the rights conveyed by the Federal Government."



b. Compliance

Decisions on the leasing schedule are, for the most part, separable from decisions on bid evaluation procedures and the minimum bid. However, the decision will be made on bid evaluation procedures and the minimum bid contemporaneously with other decisions on the program so that means for assuring receipt of fair market value are clearly indicated as part of the Proposed Final Program. A paper discussing the conceptual underpinnings of this requirement and of the general approaches considered in meeting it can be found in Appendix K.

6. 18(b)

a. Requirement

"The leasing program shall include estimates of the appropriations and staff require to--

(1) obtain resource information and any other information needed to prepare the leasing program required by this section;

(2) analyze and interpret the exploratory data and any other information which may be compiled under the authority of this Act;

(3) conduct environmental studies and prepare any environmental impact statement required in accordance with this Act and with section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332(2)(C)),; and

(4) supervise operations conducted pursuant to each lease in the manner necessary to assure due diligence in the exploration and development of the lease area and compliance with the requirements of applicable law and regulations, and with the terms of the lease."

b. Compliance

These estimates appear in the decision materials for the Proposed Final Program in Part II.F and Appendix T.

# APPENDIX B

## SUMMARY OF COMMENTS

## ON THE PROPOSED PROGRAM

SUMMARY OF COMMENTS ON THE PROPOSED 5-YEAR OCS OIL AND GAS LEASING PROGRAM (FEBRUARY 1986)

CONTENTS

## I. Introduction

Section 18 of the Outer Continental Shelf (OCS) Lands Act Amendments requires the Secretary of the Interior (Secretary) to invite and consider suggestions on preparation of a 5-year leasing program from interested Federal Agencies, including the Attorney General, in consultation with the Federal Trade Commission, and from the Governors of coastal States affected under the proposed leasing program. The Secretary may also invite or consider any suggestions from the executive of any affected local government in an affected coastal State, which have been previously submitted to the Governor of such State, and from any other person.

Before preparation of the Draft Proposed 5-Year OCS Oil and Gas Leasing Program, an initial request for comments was made on July 11, 1984, with the publication of a Federal Register notice requesting comments (49 FR 28332) and with the mailing of letters to the Governors of all coastal States and various Federal Agencies. A summary of the comments received in response to that request was presented in Appendix B of the Draft Proposed Program and is incorporated by reference in this, the Proposed Final Program.

On March 22, 1985, the Secretary transmitted copies of the Draft Proposed 5-Year OCS Oil and Gas Leasing Program to the Governors of the affected coastal States and to the heads of affected Federal Agencies for review and comment. A Federal Register Notice requesting public comments on the schedule and policies selected as the Draft Proposed Program was also published on March 22, 1985 (50 FR 11585). Although public views were requested on any topic related to the new 5-year program, respondents were asked to provide comments on specific topics concerning size, timing, and location aspects of the program. A summary of the responses received was presented in Appendix B of the Proposed Program and is incorporated herein by reference.

The Secretary transmitted copies of the Proposed 5-Year OCS Oil and Gas Leasing Program to State Governors and Federal Agency heads on February 6, 1986, and comments on the program were solicited in the Federal Register on February 7, 1986 (51 FR 4816). As with the Draft Proposed Program, general response to the program was invited, but specific topics also were presented for comment (see text of 51 FR 4816 in Appendix M of this document).

In addition to the requests for comments on the program's major proposals, industry respondents in particular were requested to rank the proposed planning areas at each stage in the development of the 5-year program. Only 24 planning areas were under consideration in July 1984 when the initial Federal Register Notice requesting comments was published. Under the Draft Proposed Program, the OCS was reconfigured into 26 planning areas by dividing the South Atlantic into two areas (South Atlantic and Straits of Florida) and by subdividing the planning areas off California from two to three. The character of these 26 planning areas was altered substantially by the Secretary's decision to defer 15 subareas at the Proposed Program stage, so the February 7, 1986, Federal Register request for comments asked that industry rank all 26 planning areas again.

Industry was requested to provide separate rankings for hydrocarbon potential and for exploration and development interest for the 26 planning areas. It was requested that both sets of rankings be based on estimates of resources expected to be unleased as of January 1987. See Appendix D for an analysis of the industry rankings.



This summary of comments is organized into three major sections. Section I is the introduction. Section II is an analysis of the responses by number and source and by geographic distribution. Section III is a summary of comments by subject which is divided into two parts: (A) comments addressing Federal Register topics; and (B) comments addressing additional topics pertaining to the Proposed Program. Several other topics which are relevant to the OCS leasing program are not addressed in this appendix but are summarized and addressed in the final environmental impact statement. Such topics include multiple use issues, conservation and alternative energy, environmental studies, and lease stipulations and other mitigating measures.

## II. Analysis of Responses

### A. Number and Source of Responses

As of October 3, 1986, a total of 3,430 comments on the Proposed Program were received in response to the Federal Register request. This number includes all correspondence submitted directly to the Department of the Interior and all comments included as enclosures to such correspondence. To facilitate the analysis and summary, comments were grouped into eight categories based on their source. Following is a listing of the categories and the number of responses received from each:

| | |
|---|---|
| Federal Agencies | 8 |
| State Governments | 23 |
| State Agencies | 38 |
| Local Governments | 55 |
| Petroleum and Related Industries/Associations | 80 |
| Environmental/Other Interest Organizations | 72 |
| Private Citizens | 3,147 |
| Congress | 7 |
| Total: | 3,430 |

#### 1. Federal Agencies

Responses were received directly from eight Federal Agencies. Six letters expressed substantive comments on the 5-year program. They were received from the Department of Defense (Department of the Navy), Department of Energy, National Aeronautics and Space Administration, Environmental Protection Agency, National Oceanic and Atmospheric Administration, and Advisory Council on Historic Preservation.

#### 2. State Governors

Letters were received directly from the Governors of 20 States: Alabama, Alaska, California, Connecticut, Delaware, Florida, Hawaii, Louisiana, Maine, Maryland, Massachusetts, Mississippi, New Hampshire, New Jersey, North Carolina, Oregon, Rhode Island, Texas, Virginia, and Washington. Letters received from California, Florida, North Carolina, Oregon, and Texas enclosed correspondence received by the respective States from agencies, local governments, and other interested parties. Alaska, California, and Virginia each submitted two letters.

3. State Agencies

State agency responses were received directly and as enclosures to Governors' letters. Comments representing State agencies, commissions and legislatures were received from nine States: California (23), Florida (5), Georgia (2), New York (1), North Carolina (1), Oregon (3), South Carolina (1), Texas (1), and Virginia (1).

4. Local Governments

Local government responses were received directly and as enclosures to Governors' letters. Comments representing city and county governments and regional government associations were received from four States: Alaska (3), California (42), Florida (9), and North Carolina (1).

5. Petroleum and Related Industries/Associations

Industry responses were received directly and as enclosures to Governors' letters. Comments were received from petroleum industry associations (10); related industry associations (9); exploration and production companies (20); support industry companies (17); and national, State, and regional highway users organizations (24). The last category is composed of groups of businessmen, industry and labor representatives, executives of trade and agricultural organizations and civic leaders working to influence decisions on highway transportation and related issues such as energy supply and fuel conservation.

6. Environmental and Other Interest Organizations

Organization responses were received directly and as enclosures to Governors' letters. Comments were received from national environmental organizations (4); local and regional environmental organizations (36); fishermen's associations (2); political and civic associations (22); and various other organizations (8). One of these letters expressed comments on behalf of the Natural Resources Defense Council, Sierra Club, Environmental Policy Institute, Greenpeace U.S.A., Trustees for Alaska, and Oregon Natural Resources Council.

7. Private Citizens

Private citizen responses were received directly (nearly 1400) and as enclosures to Governors' letters (over 1700). Several of the comments enclosed with the Governor of California's letter are duplicates of comments submitted directly to the Department. Therefore, a significant number of comments have been counted twice in the total of 3,147.

The overwhelming majority of private citizen responses came from residents and former residents of California, including hundreds of copies of form letters opposing OCS leasing which were clipped from California newspapers. Multiple private citizen responses were received from only four other States: Florida (31), Washington (9), Oregon (3), and Alaska (6).

8. Congress

Six congressional letters were received directly by the Department of the Interior and one was enclosed with the Governor of California's letter. The six direct responses came from three members of the House of Representatives and one member of the Senate, all representing Florida. The other response originated from a member of the House of Representatives from California.



B. Geographic Distribution of Responses

1. Federal Agencies

All Federal Agency responses originated from headquarters offices in Washington, D.C.

2. State Governors

Governors' comments originated from all four OCS Regions. Following is a breakdown of letters received by Region:

| | | |
|---|---|---|
| Atlantic | - | 13* |
| Gulf of Mexico | - | 5* |
| Pacific | - | 4 |
| Alaska | - | 2 |

*One letter from Florida is counted in both Regions.

3. State Agencies

State Agency comments came from only three OCS Regions. Following is a breakdown of letters received by Region:

| | | |
|---|---|---|
| Atlantic | - | 11* |
| Gulf of Mexico | - | 6* |
| Pacific | - | 26 |
| Alaska | - | 0 |

*Five letters from Florida are counted in both Regions.

4. Local Governments

Local Government comments came from all four OCS Regions. Following is a breakdown of letters received by Region:

| | | |
|---|---|---|
| Atlantic | - | 7* |
| Gulf of Mexico | - | 5* |
| Pacific | - | 42 |
| Alaska | - | 3 |

*Two letters from Florida are counted in both Regions.

5. Petroleum and Related Industries/Associations

Industry comments originated from a wide variety of sources and addressed matters pertaining to all four OCS regions. However, a breakdown of comments received by Region would not be meaningful for this category.

6. Environmental and Other Interest Organizations

Four of the responses from environmental and other interest organizations were national in scope. The remaining letters were received from State, regional and local organizations and chapters and originated from three OCS Regions. Following is a breakdown of letters received by Region:

| | | |
|---|---|---|
| Atlantic | - | 13* |
| Gulf of Mexico | - | 12* |
| Pacific | - | 49 |
| Alaska | - | 0 |

*Six letters from Florida are counted in both Regions.

7. Private Citizens

Private citizens' comments were received from all four OCS Regions as well as from several noncoastal States. Most of the latter addressed proposed leasing off California, and many of the commenters identified themselves as former California residents. Some of the responses originating from noncoastal States expressed general comments and indicated no particular regional concerns. Comments which did address a particular Region have been counted as being from that Region, regardless of their actual place of origin. Following is a breakdown of letters received by Region:

| | | |
|---|---|---|
| Atlantic | - | 19* |
| Gulf of Mexico | - | 28* |
| Pacific | - | 3093 |
| Alaska | - | 6 |
| Noncoastal/no regional preference | - | 16 |

*Fifteen letters from Florida are counted in both Regions.

8. Congress

Six of the seven congressional responses came from members representing Florida. Four of these letters addressed leasing in both the Atlantic and Gulf of Mexico OCS Regions, and two pertained to leasing in the Gulf of Mexico OCS Region exclusively. The remaining letter from Congress originated from a member representing California and addressed leasing in the Pacific OCS Region.

III. Summary of Responses

A. Summary of Comments Addressing Federal Register Topics

1. THE PROPOSED CONFIGURATION OF PLANNING AREA BOUNDARIES, INCLUDING THE DEFERRAL OF LEASING IN 15 SUBAREAS.

General

° Federal Agencies:

- Environmental Protection Agency (EPA) endorsed the proposed deferral of 15 subareas.
- Department of Energy (DOE) stated that decisions to delete or defer consideration of particular subareas should be made during the presale process rather than at the program stage.

° State Governors:

- Alabama and Maine recommended that subarea deferral decisions be governed by a set process based on scientific and economic criteria.



- Massachusetts stated that economic and environmental analyses conducted in the development of the 5-year program should eliminate portions of planning areas from leasing.
- Rhode Island recommended that the option to defer subareas other than marine sanctuaries be exercised with a measure of restraint.

° State Agencies:

- California Department of Justice stated that the Secretary's criteria for making deferrals are too vague.
- New York Department of Environmental Conservation expressed concern that the Secretary did not use a consistent process for considering subarea deferrals.
- Georgia Department of Natural Resources stated that the concept of subarea deferrals is acceptable for the protection of sensitive areas as long as serious consideration is given to other environmentally sensitive areas during the presale process.

° Industry:

- A majority of commenters endorsed the proposed configuration of the 26 planning areas.
- Several commenters expressed opposition to the concept of deferring subareas at the 5-year program stage, stating that such decisions should be made during the presale process conducted for individual sales.

° Environmental and Other Organizations:

- Natural Resources Defence Council (NRDC) and Maine Audubon Society endorsed the concept of deferring subareas at the 5-year program stage, but noted a lack of set criteria to govern deferral decisions. NRDC also stated that the subarea deferrals proposed are far too limited.
- Manasota 88 called for the establishment of explicit criteria to guide selection of subarea deferrals.

Atlantic

° State Governors:

- Florida expressed support for the proposed deferral of the Atlantic portion of the Straits of Florida planning area.
- North Carolina endorsed the proposed deferral of the U.S.S. Monitor Marine Sanctuary and adjacent buffer zone.
- Delaware commented that a boundary conforming to the geological division between the Baltimore Canyon trough and the Georges Bank basin would form a more appropriate border between the Mid-Atlantic and North Atlantic planning areas than that proposed.
- Rhode Island recommended establishment of an administratively flexible boundary between the North and Mid-Atlantic planning areas to allow States involved in both areas to participate fully in the OCS program.

° Local Governments:

- Brevard County (FL) and City of Key West (FL) adopted resolutions which endorsed the proposed deferral of the Atlantic coast portion of the Straits of Florida planning area.
- City of Wilmington (NC) adopted a resolution which endorsed the proposed deferral of the U.S.S. Monitor Marine Sanctuary and buffer zone.

° Industry:

- Chevron commented that it would be appropriate to defer the Atlantic portion of the Straits of Florida planning area, the Gray's Reef Marine Sanctuary, and the U.S.S. Monitor Marine Sanctuary and buffer zone.
- Murphy Oil commented that the subarea of the Straits of Florida proposed for deferral is excessive and should be reduced to the area within 15 miles of the coast.
- API, Phillips, and Exxon expressed opposition to establishment of a separate and distinct Straits of Florida planning area and recommended that it be included in the South Atlantic.
- Tenneco stated that if a major portion of the Straits of Florida is to be deferred, the remaining area should be included in the Eastern Gulf of Mexico planning area.

° Environmental and Other Organizations:

- Carteret County Crossroads (NC) endorsed the proposed deferral of the U.S.S. Monitor Marine Sanctuary and buffer zone.
- Florida Public Interest Research Group (FPIRG) expressed confusion over whether the west coast of the Florida Keys is included in the Eastern Gulf of Mexico or the Straits of Florida planning area.

Gulf of Mexico

° State Governors:

- Florida expressed support for the proposed deferral of 186 blocks in Seagrass Beds and 23 blocks in the Florida Middle Ground from the Eastern Gulf of Mexico planning area.

° State Agencies:

- Florida Department of Environmental Regulation expressed support for the proposed deferral of blocks in the vicinity of the Florida Middle Ground.
- Texas General Land Office expressed support for the proposed deferral of the Flower Garden Banks subarea.

° Local Governments

- North Central Florida Regional Planning Council and Southwest Florida Regional Planning Council requested deferral of the Seagrass Beds and Florida Middle Ground subareas.



° Industry

- Chevron commented that it would be appropriate to defer the Seagrass Beds, Florida Middle Ground, and the Flower Garden Banks.
- Tenneco commented that the Dry Tortugas area should be offered as part of the Eastern Gulf of Mexico planning area.
- Mobil expressed concern about the proposed deferral of the Flower Garden Banks subarea.

° Environmental and Other Organizations:

- National Audubon Society (Florida Office), Manasota 88, and Seminole Audubon Society expressed support for deferral of the Seagreass Beds and Florida Middle Ground subareas.
- Florida Public Interest Research Group (PIRG) expressed confusion over whether the west coast of the Florida Keys is included in the Eastern Gulf or the Straits of Florida planning area.

° Private Citizens

- Several commenters requested that the Seagrass Beds and Florida Middle Ground subareas be permanently removed from consideration for leasing.

Pacific

° Federal Agencies:

- Department of the Navy (DOD) endorsed the proposed deferral of the Southern California Coordinated Anti-Submarine Warfare Training Area.

° State Governors:

- California endorsed the proposed configuration of the Southern, Central, and Northern California planning areas and added that subarea deferrals would further define these areas and improve the lease sale planning process. They also endorsed deferral of the 9 subareas off the State which were identified for deferral in the Proposed Program.
- Oregon and Washington commented that the proposed Washington-Oregon planning area is too large because it includes areas of no hydrocarbon potential. Oregon also commented that the proposed planning area includes waters which are too deep for leasing.

° State Agencies:

- California Department of Justice and Water Resources Control Board endorsed the proposed deferrals of subareas off California.
- California Department of Fish and Game recommended that the Santa Maria Basin be included in the Central California planning area or be treated as a separate planning area. They also endorsed the proposed deferral of subareas in the Central California planning area.
- A letter signed by 22 members of the California legislature objected to proposed expansion of the Southern California planning area. The letter also commented that the proposed subarea deferrals are insignificant deletions of areas already protected by law or established as being of no interest to industry. The California Lieutenant Governor made the same comment.

- One assemblyman commented that the proposed subarea deferrals are not equitably distributed among the three California planning areas.
- Oregon Department of Geology and Mineral Industries commented that the proposed Washington-Oregon planning area includes areas which cannot be safely or economically drilled.

° Local Governments:

- City of Oxnard endorsed the proposed deferral of nine California OCS subareas.
- City of Monterey and Association of Monterey Bay Area Governments (AMBAG) endorsed the proposed deferral of the Monterey Bay and Big Sur subareas. City of Monterey also asked that these two subareas be expanded.
- Ventura County endorsed creation of the Central California planning area as allowing for a more precise definition of problems and issues for each of the geographic regions of California.
- City of Santa Barbara and Ventura County endorsed the proposed deferral of the Channel Islands Marine Sanctuary and the Santa Barbara Federal Ecological Preserve and Buffer Zone.
- City of Carmel-by-the-Sea endorsed the proposed deferral of the Big Sur subarea but stated that the subarea is technologically off limits to industry anyway.
- City of San Luis Obispo expressed support for the reconfigured California OCS planning areas with the exception of proposed expansion of the present seaward boundary limits.
- Laguna Beach and Newport Beach expressed opposition to reconfiguring the California OCS from two to three planning areas.
- City and County of San Franciso commented that reconfiguring the California OCS into three planning areas would increase opportunities for oil and gas leasing activity. They also stated that many areas proposed for deferral already are protected by law and the total acreage proposed for deferral represents just a fraction of the California OCS.
- Marin County and Santa Cruz County stated that the California OCS planning areas are too large.
- Several local governments commented on this topic by noting the proposed reconfiguration of California OCS planning areas in resolutions stating general opposition to the Proposed Program. These include Mendocino County, Monterey County, San Luis Obispo County, San Mateo County, and Santa Cruz County.

° Industry:

- Several commenters specifically endorsed the proposed configuration of California OCS planning areas. These include: National Ocean Industries Association (NOIA), American Petroleum Institute (API), Western Oil and Gas Association (WOGA), Amoco, ARCO, BP Alaska, Chevron, Exxon, Texaco, and Unocal.
- Chevron commented that deferral of the subarea off Big Sur is appropriate.
- Conoco expressed disappointment with the proposed deferral of the subareas off Point Reyes Wilderness, the Santa Barbara Ecological Preserve and Buffer Zone, and the Coordinated Anti-Submarine Warfare Training Area.
- Murphy Oil expressed opposition to the proposed deferral of the Santa Barbara Ecological Preserve and Buffer Zone and the Channel Islands National Marine Sanctuary.



- Shell expressed concern over the proposed deferral of the subareas off Point Reyes Wilderness and off Big Sur and requested that specific portions of these subareas be offered for lease.
- API and NOIA expressed support for the proposed extension of the outer boundaries of the Northern California and Washington-Oregon planning areas.

° Environmental and Other Organizations:

- NRDC and Get Oil Out, Inc. endorsed the subarea deferrals proposed off California and stated there should be more.
- League of Women Voters of Santa Barbara and League of Women Voters of Ventura County stated that subareas protected by laws, regulations, and administrative orders must be permanently deleted from leasing rather than deferred.
- NRDC, Friends of the Sea Otter, and Oceanic Society (San Francisco Bay Chapter) commented that subareas proposed for deferral represent a small fraction of the total size of California OCS planning areas. They also noted that several of the subareas proposed for deferral are protected to some extent by existing laws, regulations, and orders.
- Sierra Club (Santa Lucia Chapter) commented that the boundary between the Central California and Southern California planning areas should be located at the same latitude as the Santa Maria River.

° Private Citizens:

- A number of commenters stated that the proposed subarea deferrals comprise too small an area and already are protected by existing laws, regulations, and orders.

<u>Alaska</u>

° Federal Agencies:

- National Oceanic and Atmospheric Administration (NOAA) commented that several planning areas include vast areas of continental slope and deep ocean basin which should be delimited as separate planning areas. They suggested that there be continental shelf planning areas (less than 200m) and off-shelf planning areas (greater than 200m). St. George Basin, Beaufort Sea, Gulf of Alaska, Kodiak, and Shumagin were cited specifically for such treatment.

° State Governors:

- Alaska commented that efforts must continue to determine the boundary between State and Federal lands.

° Industry:

- Alaska Oil and Gas Association (AOGA), BP Alaska, and Texaco specifically endorsed the proposed configuration of Alaska OCS planning areas.
- API and NOIA expressed support for the addition of Official Protraction Diagram NS 7-8 to the Beaufort Sea planning area.

° Environmental and Other Organizations:

- NRDC observed that no subareas off Alaska were proposed for deferral despite the relative size and environmental sensitivity of the Alaska OCS.

2. THE 13 SUBAREAS HIGHLIGHTED FOR FURTHER ANALYSIS AND COMMENT.

General

° Federal Agencies:

- EPA commented that all 13 subareas highlighted for further analysis should be deferred from the Final Program.

° Industry:

- Several commenters expressed opposition to deferring any of the 13 subareas highlighted for further analysis, stating that such subareas should be analyzed during the presale process conducted for individual sales.

° Environmental and Other Organizations

- NRDC expressed support for deferring all 13 subareas highlighted for further analysis and comment.

Atlantic

° Federal Agencies:

- NOAA recommended deferral of the subareas highlighted for further analysis in the Proposed Program.
- NASA, NOAA and DOD commented in favor of deferring the Kennedy Space Center Flight Clearance Zone. NASA further requested that maps and descriptions of this subarea be corrected to indicate that the zone extends 195 nautical miles rather than 170, and the southernmost tip extends to 27° N. latitude rather than 27° 30' N. latitude. NASA also identified the area off the Wallops Flight Facility (VA) as a subarea they wish to have deferred.
- EPA asked that Georges Bank, Great South Channel, and canyon areas be considered for deferral.

° State Governors:

- Connecticut recommended that the proposed subarea within 15 nautical miles of the Atlantic coast be expanded to 50 miles with specific industry nominations evaluated on a tract-by-tract basis within the subarea.
- Delaware endorsed deferral of the subarea extending 15 nautical miles from the coast.
- Florida commented that deferral of a buffer subarea off the Atlantic coast should be based on consideration of biological and current regimes, and no informed decision can be made until environmental data are acquired. They also recommended deletion of the subarea below 30° N. latitude.
- Maine recommended deferral of the Gulf of Maine subarea. They also stated that they do not support deferral of Georges Bank, but if high conflict is a criterion for deferring subareas, then Georges Bank would qualify.
- Maryland commented that a more reasonable alternative to the 15 nautical-mile subarea would be an arbitrary distance of 30 miles from shore such as that being considered for Florida's Gulf coast.
- Massachusetts recommended that the Gulf of Maine, the Georges Bank region to 400 meters, and submarine canyon areas be deferred.



- New Jersey recommended deferral of the subarea within 50 miles of the coast.
- North Carolina requested deferral of the area extending seaward to the 200-meter isobath.
- Rhode Island commented that 15 miles is the lowest distance requested by Atlantic States for a coastal deferral and may not be appropriate.
- Virginia requested deferral of areas within 50 miles of the coast and areas in offshore canyon heads.

° State Agencies:

- Georgia Department of Natural Resources endorsed deferral of the subarea within 15 nautical miles of the coast as long as proposals for alterations of this subarea are evaluated on a case-by-case basis.
- Florida Department of Natural Resources endorsed deferral of the Kennedy Space Center Flight Clearance Zone, the subarea within 15 nautical miles of the coast, and the southern portion of the Straits of Florida planning area.
- Florida Department of Environmental Regulation endorsed deferral of the Kennedy Space Center Flight Clearance Zone and the subarea within 15 nautical-miles of the coast, but noted that the latter may not be sufficient. They also urged permanent deletion of the entire Straits of Florida planning area.
- Florida Coastal Resources Citizens Advisory Committee commented in favor of deferring the entire Straits of Florida planning area.
- New York Department of Environmental Conservation requested deferral of the area within 50 miles of shore, canyon areas, and the area north of 40° 15'.
- North Carolina Division of Marine Fisheries and Division of Coastal Management recommended deferral of the area shoreward of the 200 meter isobath.
- Virginia Council on the Environment requested that leasing be prohibited within 50 miles of shore and in canyon heads.

° Local Governments:

- South Florida Regional Planning Council commented that deferral of the entire Straits of Florida planning area is imperative.
- Brevard County (FL) and Volusia County (FL) endorsed deferral of the Kennedy Space Center Flight Clearance Zone. Brevard also endorsed deferral of the area within 15 nautical miles of the coast.
- City of Wilmington (NC) recommended deferral of the area shoreward of the 200 meter Isobath.

° Industry:

- Murphy Oil commented that deferral of the Atlantic OCS subareas highlighted for further analysis would be acceptable.

° Environmental and Other Organizations:

- Association for the Preservation of Cape Cod, Inc. commented that Georges Bank should be deleted from all leasing plans.
- Maine Audubon Society requested deferral of the Gulf of Maine.
- Massachusetts Audubon Society requested deferral of Georges Bank and areas shallower than 400 meters, submarine canyons, areas within 50 miles of the coast, and the Gulf of Maine.
- League of Women Voters of Massachusetts commented that Georges Bank, the shelf/slope break, and the areas 400 meters or shallower off the Massachusetts coast should be deferred.

- NRDC recommended deferral of Georges Bank and areas shallower than 400 meters and areas within 50 miles of the Atlantic coast.
- Carteret County Crossroads (NC) and Georgia Conservancy requested deferral of the area extending seaward to the 200-meter isobath.
- National Audubon Society (Florida Office), Sierra Club (Florida Chapter), and Friends of Canaveral recommended deferral of the area with 15 miles of the Atlantic coast. Friends of Canaveral also recommended deferral of the Kennedy Space Center Flight Clearance Zone.
- Florida Defenders of the Environment, Inc. adopted a resolution supporting permanent deletion of the area in and around the Florida Keys and the Straits of Florida.
- Florida PIRG recommended deferral of a 30-mile buffer zone around the entire Florida coast.

° Private Citizens:

- A number of commenters requested deferral of an area ranging within 15 to 50 miles of the coast.

° Congress:

- Senator Lawton Chiles endorsed deferral of the subareas which the State of Florida requested to be deferred.

Gulf of Mexico

° Federal Agencies:

- NOAA recommended deferral of the subareas highlighted for further analysis in the Proposed Program.

° State Governors:

- Florida requested deferral of the subarea between 20 to 30 miles off the Gulf coast from Naples to Apalachicola and asked that 15 blocks in the Gainesville Map area and 97 blocks off Apalachicola Bay, all of which were deleted from Sale 94, be included in this deferral. Florida also stated opposition to leasing in the area south of 26° N. latitude and east of 82° W. longitude.

° State Agencies:

- Florida Department of Natural Resources requested deferral of the subarea between 20-30 miles off the Gulf coast from Naples to Apalachicola and the Florida Bay area.
- Florida Department of Environmental Regulation recommended deferral of the subarea between 20-30 miles off the Gulf coast from Naples to Apalachicola and asked that 15 blocks in the Gainesville Map area and 97 blocks off Apalachicola Bay be included in this deferral. They also requested permanent deletion of all areas south of 25° N. latitude and east of 82° W. longitude.
- Florida Coastal Resources Advisory Committee requested that the area of the Gulf south of 26° N. latitude be deferred.



° Local Governments

- South Florida Regional Planning Council and Sarasota County recommended deferral of the subarea within 20 to 30 miles of the Gulf coast and the subarea south of 26° N. latitude and east of 82° W. longitude.
- North Central Florida Regional Planning Council recommended permanent deletion of the subarea within 30 miles of the Gulf coast from Naples to Apalachicola.
- Southwest Florida Regional Planning Council recommended deferral of the subarea within 30 miles of the Gulf coast from Naples to Apalachicola and the subarea south of 26° N. latitude and east of 82° W. longitude.
- City of Key West (FL) adopted a resolution calling for deferral of the subarea below 26° N. latitude.

° Industry:

- Murphy Oil commented that deferral of the Gulf of Mexico subareas highlighted for further analysis would be acceptable.
- Tenneco specifically expressed opposition to deferral of the subarea extending 20 to 30 nautical miles offshore from Naples to Apalachicola and the subarea south of 26° N. latitude and east of 82° W. longitude.

° Environmental and Other Organizations:

- Florida Defenders of the Environment, Inc. adopted a resolution supporting permanent deferral of the subarea south of 26° N. latitude and east of 82° W. longitude and areas in and around the Florida Keys and the Straits of Florida.
- Izaak Walton League (Region V), Sierra Club (Florida Chapter), and Manasota 88 recommended deferral of the area south of 26° N. latitude. The latter two also recommended deferral of a subarea within 30 miles of the Gulf coast, and Manasota 88 expressed opposition to leasing in Apalachicola Bay.
- New Smyrna Beach (FL) Audubon Society, National Aubudon Society (Southeast Florida Office) and Florida National High Adventure Sea Base recommended deferral of the subarea within 30 miles of the Gulf coast.
- Greenpeace recommended deferral of the subarea within 50 miles of Florida's Gulf coast and the subarea south of 26° N. latitude.
- National Audubon Society (Florida Office) called for deferral of the subarea within 20 to 30 miles of the Gulf coast and the area south of 26° N. latitude and 82° W. longitude.
- NRDC expressed support for deferral of the area within 30 miles of the Florida Middle Ground, the area within 30 miles of the Florida coast from Apalachicola to the Alabama border, and the area south of 26° N. latitude and east of 84° W. longitude.
- Seminole Audubon Society requested deferral of the area adjacent to Everglades National Park south of Naples and the area within 15 miles of the Florida Gulf coast from Naples to Apalachicola.
- Florida PIRG recommended deferral of the subarea within 30 miles of the entire coast of Florida (including 112 Gulf blocks deferred from previous sales) and the area south of 26° N. latitude and east of 82° W. longitude.

° Private Citizens:

- Several commenters requested deferral of a subarea ranging from 20-50 miles off Florida's Gulf Coast and deferral of areas of the OCS between Naples and the Keys.

° Congress:

- Senator Lawton Chiles endorsed deferral of the subareas which the State of Florida requested to be deferred.
- Congressman C. W. Bill Young endorsed the establishment of a coastal buffer zone identical to the one applied to Sale 94.
- Congressman William Lehman expressed opposition to leasing in the area south of 25° N. latitude and east of 82° W. longitude.
- Congressman Dante B. Fascell expressed opposition to leasing around the Florida Keys or in the Straits of Florida.

Pacific

° Federal Agencies:

- NASA noted that the offshore launch range at Vandenberg Air Force Base (AFB) California is an area of concern.
- DOD stated that they will seek deferral of the Vandenberg AFB offshore launch area.
- EPA asked that the area within 6 miles of the coast in the Washington/Oregon planning area be considered for deferral. They also asked that Stonewall, Perpetua, and Heceta Banks be considered for deferral.

° State Governors:

- California endorsed deferral of the two subareas off the State which were highlighted for further analysis in the proposed program and requested deferral of the following additional subareas:
- Subareas adjacent to areas protected by State and local laws, goals, and policies:

-- Subareas Offshore State Areas of Special Biological Significance

(1) Pygmy Forest Ecological Staircase - Mendocino County
(2) Del Mar Landing Ecological Reserve - Mendocino County
(3) Gerstle Cove - Sonoma County
(4) Bodega Marine Life Refuge - Marin County
(5) Kelp Beds at Saunders Reef - Mendocino County
(6) Kelp Beds at Trinidad Head - Humboldt County
(7) Kings Range National Conservation Area - Humboldt County
(8) Redwoods National Park - Del Norte County
(9) James V. Fitzgerald Marine Reserve - San Mateo County
(10) Farallon Islands - San Francisco County
(11) Duxbury Reef Reserve and Extension - Marin County
(12) Point Reyes Headland Reserve and Extension - Marin County
(13) Double Point - Marin County
(14) Bird Rock - Marin County
(15) Ano Nuevo Point Island - San Mateo County
(16) Point Lobos Ecological Reserve - Monterey County
(17) San Miguel, Santa Rosa, and Santa Cruz Islands - Santa Barbara County



(18) Julia Pfeiffer Burns Underwater Park - Monterey County
(19) Pacific Grove Marine Gardens Fish Refuge and Hopkins Marine Life Refuge - Monterey County
(20) Ocean Area surrounding the Mouth of Salmon Creek - Monterey County
(21) San Nicolas Island and Begg Rock - Ventura County
(22) Santa Barbara Island, Santa Barbara County and Anacapa Island - Santa Barbara and Ventura Counties
(23) San Clemente Island - Los Angeles County
(24) Mugu Lagoon to Latigo Point - Ventura and Los Angeles Counties
(25) Santa Catalina Island - Subarea One, Isthmus Cove to Catalina Head - Los Angeles County
(26) Santa Catalina Island - Subarea Two, North End of Little Harbor to Ben Weston Point - Los Angeles County
(27) Santa Catalina Island - Subarea Three, Farnsworth Bank Ecological Reserve - Los Angeles
(28) Santa Catalina Island - Subarea Four, Binnacle Rock to Jewfish Point - Los Angeles
(29) San Diego - La Jolla Ecological Reserve - San Diego County
(30) Heisler Park Ecological Reserve - Orange County
(31) San Diego Marine Life Refuge - San Diego County
(32) Newport Beach Marine Life Refuge - Orange County
(33) Irvine Coast Marine Life Refuge - Orange County
(34) Carmel Bay - Monterey County

-- All blocks within 3 miles of the seaward boundary of California oil and gas sanctuaries offshore:

(1) Del Norte County;
(2) Humboldt County from Cape Mendocino to south of the Mendocino County border;
(3) The area from Sonoma County to Point Sal in Santa Barbara County, including the Farallon Islands San Francisco Bay - Bay Delta System west of the Carquinez Bridges, and Monterey Bay;
(4) The area from Goleta Point to the City of Santa Barbara;
(5) Los Angeles County from the Ventura county border to Point Fermin;
(6) Orange and San Diego Counties from the northerly border of the City of Newport Beach south to the International Border; and
(7) San Clemente, Santa Catalina, Anacapa, Santa Cruz, Santa Rosa, and San Miguel Islands.

- Subareas identified for deferral through prior lease sale analyses:

-- Sale 48

(1) 15 tracts off Dana Point and San Diego County
(2) 22 tracts off Orange and San Diego Counties and in the Santa Barbara Channel
(3) 24 tracts in the Santa Barbara Channel
(4) 5 tracts in DOD use areas
(5) 3 tracts in the Long Beach Precautionary Area

-- Sale 53: 131 tracts not offered for lease in Eel River, Point Arena, Bodega, and Santa Cruz basins

-- Sale 68:

(1) 23 tracts south of Santa Barbara Island (DOD use area)
(2) 35 tracts in the Channel Islands Marine Sanctuary (already deferred)
(3) 8 tracts in the Santa Barbara Preserve Buffer Zone (already deferred)
(4) 24 tracts off Santa Monica Beach Harbor, and Orange County (included in the request above).

-- Sale 73:

(1) 64 tracts deferred from the sale because under lease
(2) 16 tracts under litigation re: Sale 53
(3) 22 tracts specified in the MOA with California
(4) 121 tracts in DOD use areas

-- Sale 80:

(1) 18 tracts adjacent to Channel Islands Marine Sanctuary, Santa Catalina Island, and the Mugu Lagoon to Latigo point
(2) Tracts deleted for military reasons
(3) 6 mile buffer zone around San Nicolas Island and Begg Rock
(4) Santa Monica Bay from Point Mugu to Point Fermin
(5) Tracts off San Diego Bay (per EIS Alternative VII)
(6) Tracts in the Long Beach - Los Angeles vessel precautionary area

- Subareas with other resources

-- Sea Otter Range (tracts within 12 miles of shore within the range of the threatened Southern Sea Otter from Point Ano Nuevo to the Santa Maria River).

-- Santa Monica Bay

(1) Tracts deleted in previous sales
(2) Tract deletions negotiated in Sale 80
(3) ". . . Most of the additional tracts identified in the letter from the City of Santa Monica . . . ."

-- San Diego County: the Sale 80 DEIS deferral request, "with minor modifications . . . ."

- Vessel Traffic Areas

-- 2 additional blocks in the San Francisco vessel precautionary area

-- Precautionary area off the ports of Long Beach and Los Angeles

- Oregon commented that even if the subarea estimated to be beyond the area of hydrocarbon potential is deferred, the Washington-Oregon planning area still will be too large and will include excessively deep waters. Also, the following areas were requested to be deferred:



-- Heceta Bank, Stonewall Bank, and Perpetua Bank;
-- Coquille Banks, southwest of the mouth of the Coquille River;
-- Oregon Islands National Wildlife Refuge and a 6-mile buffer;
-- the mouth of Coos Bay and 6-mile radius buffer;
-- the mouths of the Columbia River and Yaquina Bay and 6-mile radius buffers; and
-- Cascade Head and Salmon River Estuary Scenic Research Area and a 6-mile radius buffer.

- Washington requested deferral of the area north of the 47th parallel; the areas within 12 nautical miles of the Grays Harbor, Willapa Bay, and Columbia River estuaries; and deepwater areas beyond the continental shelf itself.

° State Agencies:

- California Coastal Commission expressed opposition to any leasing off the State and specifically requested deferral of the northern Santa Maria Basin and the offshore area between Santa Barbara Channel and the Mexican border.
- California Department of Justice requested deferral of Santa Barbara Channel, Santa Monica Bay, and areas adjacent to Southern Orange County and San Diego County. They also stated that a number of other areas should be deferred, citing the areas off Mendocino County and San Mateo as examples.
- A letter signed by 22 members of the California Legislature requested deferral of the following subareas:

-- the areas within a 12-mile buffer zone from the San Diego County/Mexico boundary to Newport Beach in Orange County;
-- the area within the access routes to the Ports of Los Angeles, Long Beach, and San Luis;
-- the area within and immediately adjacent to Santa Monica Bay;
-- the areas off San Mateo and Santa Cruz Counties; and
-- the area north of the Santa Maria River.

- California's Lieutenant Governor recommended deletion of the four Northern California basins, the areas near Santa Monica Bay and Orange and San Diego Counties, and the offshore area between Santa Barbara Channel and the Mexican Border.
- California Department of Parks and Recreation recommended deferral of State Seashores, Areas of Special Biological Significance, the Point Dume-Malibu area, the Bolsa Chica-Huntington Beach area, Crystal Cove State Park Underwater Preserve, and the Carlsbad-International Boundary area.
- California Department of Fish and Game recommended deferral of areas in the Southern California Bight which have been delineated as heavy species use areas or critical habitat of endangered species or unique populations; blocks within 12 miles of the Sea Otter Game Refuge and Point Estero; the areas off Santa Cruz, San Mateo and San Francisco Counties to the 500 fathom contour; the area from Bodega Head to the northern boundary of the Central California planning area; and an additional 40 blocks in the vicinity of Cordell Bank.

- California Department of Conservation, Division of Oil and Gas, recommended deferral of the areas near San Diego and Orange Counties and the offshore area extending from Morro Bay to the northern boundary of Monterey Bay.
- California State Water Resources Control Board recommended deferral of the areas within 6 miles of Areas of Special Biological Significance.
- One assemblyman in the California legislature stated that protection must be provided for areas which have been under moratorium in the past.
- Oregon Department of Geology and Mineral Industries stated that the Heceta and Stonewall Banks areas should be delineated and deleted.

° Local Governments:

- AMBAG stated that a balanced leasing program would defer the Santa Cruz Basin.
- City of Carlsbad adopted a resolution requesting deletion of the area off San Diego County.
- City of Coronado requested deferral of areas included in previous Congressional moratoria, blocks which have not received bids in previous sales, blocks requested to be deleted from Sale 80 by the Defense Department, and blocks in waters deeper than 400 meters.
- City of Huntington Beach recommended deletion of areas adjacent to State Waters.
- City of Lompoc requested that leasing in Santa Maria Basin be deferred until compliance with proper air quality standards can be assured.
- City of Irvine requested deferral of all areas south of Point Conception.
- City of Laguna Beach recommended deferral of the area off Orange County extending to Catalina Island.
- Monterey County recommended deferral of the offshore areas north of the Santa Maria River, blocks within 6 nautical miles of Catalina Island, blocks in Santa Monica Bay and the area off Orange and San Diego Counties. They also recommended deferral of blocks within Santa Barbara Channel until cumulative impact problems are resolved and stated that the Eel River, Bodega, Point Arena, and Santa Cruz basins are biological and scenic resource areas which contain relatively small potential hydrocarbon resources.
- City of Newport Beach recommended deferral of local marine environmentally sensitive areas such as Newport Beach Marine Life Refuge.
- City of Oceanside and San Diego Association of Governments recommended deletion of blocks deleted from previous sales; blocks which have not been bid upon by industry; blocks which the Department of Defense requested be deferred from Sale 80; blocks in waters deeper than 400 meters; nearshore blocks that would adversely impact the air quality of the San Diego region; and nearshore blocks adjacent to sensitive biological resources off the San Diego coastline, including the Santa Margarita River, Oceanside Harbor, the San Luis Rey River, and Buena Vista Lagoon. They also recommended deletion of areas previously covered by Congressional moratoria.
- Orange County recommended deletion of the entire area off the county to Catalina Island.
- City of Oxnard commented that additional areas of special biological or scenic significance should be identified and deferred.
- City of Palos Verdes Estates expressed opposition to leasing any blocks off the Palos Verdes coast.
- City of Redondo Beach, City of Torrance, and City of Santa Monica recommended deletion of Santa Monica Bay. Santa Monica also recommended deletion of shipping lanes west of the bay.



- San Diego County recommended deletion of blocks within 3 to 27 miles of the coast.
- City of San Diego requested deferral of blocks offered but not bid on in previous sales off San Diego, blocks deleted from previous sales, areas covered by previous Congressional moratoria, and blocks in waters deeper than 400 meters (until proven production technology is developed for such depths).
- City of San Luis Obispo and San Luis Obispo County recommended deferral of a 12-mile buffer around the sea otter range and a 20-mile buffer around Morro Bay.
- Santa Barbara County requested that leasing in Santa Barbara Channel and Santa Maria Basin be deferred until the cumulative aspects of existing development are documented and it can be established that local infrastructure can accommodate further development.
- South Coast Air Quality Management District recommended deferral of leasing off Southern California pending the outcome of negotiated rulemaking concerning air quality.
- Ventura County recommended deferral of the Santa Barbara Channel and Santa Maria Basin until compliance with air quality standards can be assured.

° Industry:

- Murphy Oil commented that deferral of the California OCS subareas highlighted for further analysis would be acceptable.

° Environmental and Other Organizations:

- Friends of the Irvine Coast recommended deferral of the offshore area between Corona Del Mar and Laguna Beach.
- Friends of the Coast expressed opposition to leasing the offshore area from Morro Bay to the Oregon border.
- Friends of the Sea Otter requested deletion of all waters north of Santa Maria River, as well as areas in southern California previously protected by Congressional moratoria.
- Get Oil Out, Inc., League of Women Voters Northern California Coalition, and League of Women Voters of Sacramento recommended deferral of the offshore areas north of Santa Maria River including Eel River, Bodega, Point Arena, Santa Cruz, and northern Santa Maria Basin. Get Oil Out, Inc. also recommended deferral of blocks within 6 nautical miles of Catalina Island and blocks off Santa Monica Bay and San Diego.
- League of Women Voters of San Luis Obispo recommended deletion of areas where onshore topography would necessitate tankering of crude oil, areas with uneconomical reserves, areas of biological significance to fisheries as identified by the California Coastal Commission, and the area 3 to 15 miles off the coast between Point Sal and Point Arguello.
- League of Women Voters of Santa Barbara recommended deferral of leasing in Santa Barbara Channel and Santa Maria Basin until MMS air quality regulations are modified to require that OCS emissions be subject to the same controls as onshore emissions.
- League of Women Voters South Central Regional Task Force and League of Women Voters of Ventura County recommended deferral of certain blocks off Point Mugu and adjacent to the State designated Area of Special Biological Significance.

- League of Women Voters of Santa Cruz recommended deferral of Santa Cruz Basin.
- Monterey Peninsula Chamber of Commerce expressed opposition to leasing in Monterey Bay and along the coast to the San Luis Obispo County line.
- Newport Heights Community Association recommended deferral of Catalina Channel and nearshore blocks.
- Pacific Coast Federation of Fishermen's Associations recommended deferral of the areas surrounding Monterey Canyon and San Nicolas Island.
- Sierra Club (Santa Lucia Chapter) recommended deferral of the offshore area between Santa Maria River and Monterey Bay.
- Desomount Club urged deletion of the OCS area adjacent to the Orange County coastline.
- California Native Plant Society recommended deferral of the 70-mile strip of coastline from the Sinkyone State Wilderness Park, along the proposed King Range Wilderness Area, and up to the mouth of the Eel River.
- NRDC endorsed California Coastal Commission's recommendations concerning subarea deferrals.

° Private Citizens:

- Several commenters recommended deferral of one or more of the subareas described above by other commenters addressing this topic.

° Congress:

- Congressman Robert Badham recommended deferral of the entire Orange County coast.

Alaska

° Federal Agencies:

- EPA recommended deferral of all blocks within a 50-mile radius of Unimak Pass, thereby expanding the subarea defined by the MMS in the Proposed Program to include blocks in the Shumagin planning area. They also asked that the following areas be considered for deferral: within 50 miles of Pribilof Islands; within 25 miles of Yukon Delta; from 3-44 miles offshore in the Beaufort Sea Basin; Inner Bristol Bay; all blocks within 60 miles of the north side of the Aleutian Islands; and all areas deeper than 3000 meters.

° State Governors:

- Alaska recommended deferral of blocks within 35 miles of Unimak Pass, 39 miles of the Pribilof Islands, 12 miles of the Yukon Delta, and traditional subsistence hunting areas in close proximity to Point Barrow.

° Local Governments:

- Bristol Bay Coastal Resource Area recommended establishing buffers around Unimak Pass, the Pribilof Islands, and other documented environmentally sensitive areas.
- North Slope Borough recommended deferral of the 59 blocks off Point Barrow which the Proposed Program highlighted for further analysis.

° Industry:

- Murphy Oil expressed opposition to deferral of the 59-block area off Point Barrow, stating that the area may have some hydrocarbon potential.



° Environmental and Other Organizations:

- Institute for Resource Management's comments addressed all Bering Sea planning areas except the North Aleutian Basin and recommended deferral of subareas within the Norton Basin, Navarin Basin, and St. George Basin. NRDC endorsed these recommendations.

3. THE APPROPRIATENESS OF THE NUMBER OF PROPOSED SALES AND THE INTERVAL BETWEEN PROPOSED SALES; AND, IN PARTICULAR, WHETHER THERE SHOULD BE BIENNIAL RATHER THAN TRIENNIAL SALES IN THE EASTERN GULF OF MEXICO.

General

° Federal Agencies:

- EPA endorsed the proposed scheduling of annual sales in the Central and Western Gulf of Mexico planning areas and triennial sales elsewhere.
- DOD endorsed the proposed pace of leasing for allowing a more deliberate process and additional time for conflict resolution.
- DOE stated that they are pleased that the pace of the Proposed Program is similar to that announced in the Draft Proposed Program (March 1985).

° State Governors:

- New Hampshire, New Jersey, Rhode Island and Virginia endorsed the overall pace of leasing proposed.
- Alabama commented that the pace of leasing in planning areas other than Central and Western Gulf of Mexico is insufficient.
- Louisiana and Texas commented that slowing the pace of leasing in all planning areas other than Central and Western Gulf of Mexico results in an unbalanced program.

° Industry:

- Several commenters stressed the importance of reliability and predictability in the leasing schedule.
- BP Alaska stated that the total number of sales on the proposed schedule is acceptable.
- Chevron, Unocal, and Standard expressed agreement with the overall proposed schedule. Standard also noted that the acceleration provision is expected to step up the pace of leasing in frontier areas of encouragement.
- Murphy Oil and ARCO commented that the proposed pace of leasing would be acceptable if flexibility provisions are instituted and prove effective.
- Amoco, Mobil, Tenneco, and Texaco commented that triennial leasing is not compatible with regulations requiring public release of well information 2 years after its date of submission.
- Amoco, Odeco, Phillips, Zapata, API, NOIA, WOGA, and Offshore Operators Committee (OOC) expressed support for biennial leasing in planning areas other than Central and Western Gulf of Mexico. Amoco stated that biennial leasing would be appropriate in all planning areas except those in the Atlantic.
- Conoco stated that triennial sales would be preferable in most frontier areas.
- Tenneco expressed opposition to triennial leasing and support for a biennial pace.

- Dixilyn-Field and Pogo expressed concern about the overall slower pace of leasing proposed.

° Environmental and Other Organizations:

- Whale Center stated that the pace of the proposed schedule is too fast.
- NRDC commented that the proposed schedule is based on flawed economic assumptions (e.g., those concerning oil prices and discount rate) and an inadequate sampling of industry interest.

° Private Citizens:

- Several commenters stated that too many sales are proposed and the interval between them is too short.

Atlantic

° State Governors:

- Delaware, Florida, Maine, New Jersey, North Carolina and Rhode Island endorsed the proposed number of Atlantic sales and the interval between them.
- Massachusetts expressed opposition to scheduling two sales in the North Atlantic planning area and a total of four in the entire Atlantic Region.

° State Agencies:

- Florida Department of Environmental Regulation, New York Department of Environmental Conservation, and North Carolina Department of Natural Resources and Community Development endorsed the slower pace of leasing proposed.

° Local Governments:

- Volusia County (FL) endorsed triennial leasing.

° Industry:

- Amoco commented that biennial leasing would not be appropriate in the Atlantic planning areas.

° Environmental and Other Organizations:

- Florida PIRG endorsed triennial leasing.
- Massachusetts League of Women Voters recommended a slowdown in the pace of leasing.
- Friends of Canaveral commented that the leasing pace in the South Atlantic should be slowed to accommodate environmental studies and completion of the space shuttle Challenger investigation.
- National Audubon Society (Florida Office) and Sierra Club (Florida Chapter) commented that environmental studies should be completed before leasing is conducted.



° Congress:

- Senator Lawton Chiles recommended that leasing in the South Atlantic planning area be postponed until studies concerning the effects of normal OCS operations and the effects of oil spills are completed.

Gulf of Mexico

° State Governors:

- Florida expressed support for triennial leasing in the Eastern Gulf of Mexico planning area.
- Louisiana expressed concern over the long-term economic and environmental impacts of annual areawide leasing in the Central Gulf of Mexico planning area.

° State Agencies:

- Florida Department of Environmental Regulation and Coastal Resources Citizens Advisory Committee expressed support for triennial leasing in the Eastern Gulf of Mexico planning area. The latter also commented that leasing should not be conducted until environmental studies are completed.
- Texas General Land Office commented that Central and Western Gulf of Mexico sales should not be scheduled for April or October, as State OCS sales are held in those months.

° Local Governments:

- Sarasota County (FL) expressed support for triennial leasing in the Eastern Gulf of Mexico planning area.
- Southwest Florida Regional Planning Council expressed opposition to biennial leasing in the Eastern Gulf of Mexico planning area.

° Industry:

- Offshore Operators Committee (OOC), Anadarko, Conoco, Murphy Oil, Shell and Standard specifically recommended biennial leasing in the Eastern Gulf of Mexico planning area. Shell further recommended that Eastern Gulf sales be scheduled between sales in the Central and Western Gulf of Mexico planning areas.
- Exxon and Mobil specifically recommended triennial leasing in the Eastern Gulf of Mexico planning area.
- OOC, NOIA, WOGA Chevron, Conoco, Exxon, Odeco, Phillips, Pogo, Shell and Texaco specifically endorsed annual leasing in the Central and Western Gulf of Mexico planning areas. Phillips also recommended that there be a consistent 6 month interval between Central sales and Western sales.

° Environmental and Other Organizations:

- Florida PIRG expressed support for triennial leasing in the Eastern Gulf of Mexico planning area.
- National Audubon Society (Florida Office) and Sierra Club (Florida Chapter) commented that environmental studies should be completed before leasing is conducted.

° Congress:

- Senator Lawton Chiles and Congressmen William Lehman and Dante B. Fascell recommended that necessary environmental studies be completed before deciding to conduct lease sales in the Eastern Gulf of Mexico planning area.

Pacific

° State Governors:

- California endorsed triennial leasing in the three planning areas off its coast but expressed concern that the total number of five sales off California would result in great demands on State and local reviewing agencies. They also commented that the presale process for Sales 91 and 95 should not be initiated until after the 5-year program is approved.
- Washington requested that Sale 132 be scheduled to allow completion of pertinent environmental studies for consideration in the presale process.

° State Agencies:

- California Department of Conservation, Division of Oil and Gas, endorsed triennial leasing.
- A letter signed by 22 members of the California legislature stated that triennial leasing would be preferable to a biennial pace.
- California Coastal Commission and Department of Justice commented that the proposed schedule would offer leases at a fast pace which places a heavy burden on State and local reviewing agencies. They also noted that the addition of a third planning area would result in a total of five sales off California in five years.
- California Department of Justice and 22 members of California Legislature commented that no action should be taken on Sales 91 and 95 until the 5-year program is approved.
- California Department of Conservation, Division of Oil and Gas, commented that action on Sale 95 should be delayed until the 5-year program is approved.
- California State Water Resources Control Board recommended delaying Sale 95 until October 1988.

° Local Governments:

- Ventura County commented that the proposed schedule provides more time to review lease sales.
- City and County of San Francisco commented that the proposed leasing schedule would not slow the pace of leasing.
- City of Huntington Beach, City of Laguna Beach, and Orange County commented that there should be one sale scheduled per planning area per 5-year period. Huntington Beach also commented that no action should be taken on Sale 91 until the 5-year program is approved.
- City of Coronado, City of Oceanside, and San Diego Association of Governments commented that two sales per planning area is excessive. Coronado also commented that no action should be taken on Sale 95 until the 5-year program is approved.



- City of Carmel by the Sea and City of Newport Beach stated that the proposed pace of leasing is too fast for local government reviewers. Newport Beach also noted that addition of a third planning area would result in one sale per year off California.
- City of Monterey commented that the proposed schedule is paced unrealistically and would not allow time for properly considering environmental and economic impacts and conflicts.
- City of San Luis Obispo and San Luis Obispo County recommended that there be a minimum of 12 months between all sales and 3 years between frontier area sales. City of San Luis Obispo also stated that Sale 95 should be deferred until completion of the Final Program.
- City of Oxnard commented that the pace of leasing should be slowed until cumulative impacts of past and projected development are determined.
- Several local governments commented on this topic by noting the proposed schedule of sales in California OCS planning areas in resolutions stating general opposition to the Proposed Program. These include Mendocino County, Monterey County, Orange County, San Luis Obispo County, San Mateo County, and Santa Cruz County.

° Industry:

- NOIA, OOC, BP Alaska, Combustion Engineering, Conoco, Exxon and Odeco specifically recommended biennial leasing in California OCS planning areas. Conoco further recommended that there be a sale in one of the three planning areas every eight months, and BP Alaska suggested lengthening by a few months the interval between Sales 91 and 95.
- Chevron recommended scheduling one sale each year in the California OCS planning areas. They also recommended scheduling Sale 95 in the last quarter of 1988 and moving Sale 128 to 1990.
- Shell recommended that initial sales off the west coast be scheduled at one year intervals and follow-up sales scheduled biennially.
- Standard expressed concern that too few sales are proposed off California.

° Environmental and Other Organizations:

- Get Oil Out, Inc., Sierra Club (Santa Lucia Chapter), Friends of the Sea Otter, and the Leagues of Women Voters of Santa Cruz and Ventura commented that a schedule calling for 5 sales off California in 5 years is too fast paced. The last two expressed support for a phased schedule of leasing.
- League of Women Voters of Berkeley recommended that the pace of leasing be slowed.
- Earth First! (Santa Cruz) and Wildlife Society (Humboldt Chapter) expressed opposition to proceeding with the Sale 91 presale process before the 5-year program is approved.
- League of Women Voters of Santa Barbara commented that initiating action on Sales 91 and 95 before the 5-year program is approved would create a dilemma for State and local reviewers.
- League of Women Voters Northern California Coalition recommended that initiation of the presale process for Sale 91 be postponed until after the 5-year program is approved.

° Private Citizens:

- Several commenters stated that the Proposed Program schedules too many sales at too fast a pace. Many also expressed opposition to initiation of the presale processes for Sales 91 and 95 before the 5-year program is approved.

Alaska

° Federal Agencies:

- NOAA endorsed the proposed pace of leasing for Alaska OCS planning areas.

° State Governors:

- Alaska recommended that the lease schedule include a maximum of three sales per year off Alaska, with no more than a total of 12 sales during the 5-year period. They specifically requested that Sales 127 and 129 be dropped from the schedule.

° Local Governments:

- North Slope Borough recommended postponing Sale 109 until at least 1987 and urged that Sale 97 be deleted from the schedule or at least deferred 3 more years. They also stated that certain environmental studies should be completed before leasing is conducted.

° Industry:

- BP Alaska and Exxon specifically endorsed triennial leasing in Alaska OCS planning areas.
- Conoco and Shell specifically recommended biennial leasing in Alaska OCS planning areas. However, Conoco cited Chukchi Sea as an exception where triennial leasing would be more appropriate.
- Chevron recommended rescheduling Sale 109 to no earlier than 1989 so that a COST well could be funded and drilled. They further commented that the next following Chukchi Sea sale would have to be delayed for at least three years to allow exploration of the blocks initially leased.

4. THE APPROPRIATENESS OF THE LOCATION OF PROPOSED SALES; AND, IN PARTICULAR, WHETHER THERE SHOULD BE A SALE IN 1991 IN THAT PORTION OF THE STRAITS OF FLORIDA PLANNING AREA SOUTH OF 25° 07' N. LATITUDE.

General

° Federal Agencies:

- EPA commented that an environmentally preferable proposal for leasing would combine deferral of 28 subareas and deferral of leasing in any or all of the following six planning areas: North Atlantic, Southern California, Central California, Northern California, Washington-Oregon, and North Aleutian Basin.



° State Governors:

- New Hampshire commented that the location of proposed sales is appropriate.

° Industry:

- ARCO, BP Alaska, Chevron, Conoco, Mobil, Murphy Oil, Shell, and WOGA endorsed the location of proposed sales.

° Environmental and Other Organizations:

- NRDC commented that given existing low oil prices, several locations proposed for leasing are not economically viable and should not be offered.

Atlantic

° Federal Agencies:

- EPA specifically recommended that the North Atlantic and Straits of Florida planning areas be deferred from leasing.

° State Governors:

- Florida recommended that the Straits of Florida planning area be deleted from the leasing program.

° State Agencies:

- Florida Department of Environmental Regulation, Department of Natural Resources, and Florida Coastal Resources Citizens Advisory Committee expressed opposition to leasing in the Straits of Florida planning area.

° Local Governments:

- Sarasota County, South Florida Regional Planning Council and Southwest Florida Regional Planning Council expressed opposition to leasing in the Straits of Florida planning area.

° Industry:

- Amoco, Conoco, Mobil, Phillips, Shell, and Standard commented in favor of scheduling a sale in the Straits of Florida south of 25° 7' N. latitude in 1991.
- Murphy Oil recommended that a lease sale be scheduled for the entire Straits of Florida planning area, excluding the subarea within 15 miles of the coast.
- Exxon commented that no sale is needed in the Straits of Florida planning area.

° Environmental and Other Organizations:

- Sierra Club (Florida Chapter), Florida PIRG, Greenpeace and NRDC expressed opposition to leasing in the Straits of Florida planning area.

° Private Citizens:

- A number of commenters expressed opposition to leasing in one or more of the Atlantic planning areas.

° Congress:

- Senator Lawton Chiles and Congressmen William Lehman and Dante B. Fascell expressed opposition to leasing in the Straits of Florida planning area.

Gulf of Mexico

None

Pacific

° State Agencies:

- California Coastal Commission expressed opposition to any leasing in the California OCS planning areas.
- California Department of Justice expressed opposition to leasing in the Central and Northern California planning areas.

° Local Governments:

- Marin County recommended deletion of the Central and Northern California planning areas.
- Several local governments commented on this topic by noting the location of proposed sales off California in resolutions stating general opposition to the Proposed Program. These include Mendocino County, Monterey County, Orange County, San Luis Obispo County, San Mateo County, and Santa Cruz County.

° Industry:

- Exxon and NOIA stressed the importance of scheduling lease sales in the California OCS planning areas.

° Environmental and Other Organizations:

- Earth First! (Santa Cruz) expressed opposition to any OCS leasing off the Pacific coast.
- Environmental Allergies Organization, Pacific Coast Federation of Fishermen's Associations, and Wildlife Society (Humboldt Chapter) expressed opposition to leasing in the Northern California planning area.
- Friends of the Coast, Friends of the Sea Otter, and League of Women Voters of Sonoma County expressed opposition to leasing in the Central and Northern California planning areas.
- Friends of the Earth (Northwest Office) and Washington Trollers Association expressed opposition to leasing in the Washington-Oregon planning area.

° Private Citizens:

- Several commenters expressed opposition to leasing in one or more of the Pacific OCS planning areas.



Alaska

° Federal Agencies:

- NOAA endorsed the decision not to schedule sales in the St. Matthew-Hall, Aleutian Basin, Aleutian Arc and Bowers Basin planning areas.
- EPA specifically recommended that the North Aleutian Basin planning area be deferred from leasing.

° State Governors:

- Alaska recommended that the North Aleutian Basin planning area be deleted from the leasing program.

° Local Governments:

- Bristol Bay Coastal Resource Service Area recommended that the North Aleutian Basin planning area be deleted from the leasing program.
- North Slope Borough requested deletion or deferral of leasing in the Beaufort Sea and Chukchi Sea planning areas.

° Industry:

- AOGA endorsed the location of sales proposed off Alaska.

° Environmental and Other Organizations:

- NRDC expressed opposition to leasing in the North Aleutian Basin planning area.

° Private Citizens:

- A number of commenters expressed opposition to leasing in the North Aleutian Basin planning area.

5. THE PROPOSED PRESALE PROCESS OF FOCUSING ON PROMISING ACREAGE; AND, IN PARTICULAR, THE POSSIBLE TECHNIQUES FOR IMPLEMENTING THAT APPROACH.

° Federal Agencies:

- DOD and NOAA endorsed the concept of focusing on promising acreage.
- EPA expressed support for the proposed presale process but requested clarification of it. They also recommended that focusing be done at the area identification stage so that environmental analysis can concentrate on a smaller area.

° State Governors:

- Maine, New Hampshire, Massachusetts, Rhode Island, Delaware, Maryland, Virginia, North Carolina, and Florida expressed a general endorsement of the concept of focusing on promising acreage.
- Maine, Massachusetts, New Jersey and North Carolina recommended that nomination procedures be revised to request more detailed information from industry on areas of interest prior to issuance of the Call for Information and Nominations and again after issuance of the draft environmental impact statement.

- Maine stated that there is no basis for requesting more detailed negative nomination information and there is no need to require publication of a proposed Call area in the Federal Register.
- Connecticut suggested that a tract selection presale process be applied to areas within 50 miles of the coast.
- Delaware requested clarification of the proposed presale process and stressed the importance of making pertinent information available to States.
- Maryland expressed concern over the reliability of data at the Area Identification stage of the proposed presale process and urged close coordination with States when implementing the process.
- Florida commented that promising acreage should be delineated as early as possible in the presale process, so that analyses in the EIS can focus on those promising areas to be offered.
- Mississippi endorsed the concept of focusing on promising acreage.
- Alabama stated that the presale process should designate as a high potential subarea any portion of an OCS planning area where a major new hydrocarbon discovery is made, and maximum effort should be made to resolve conflicts concerning such a subarea.
- Louisiana expressed concern that, under the proposed presale process, larger and larger sales will take place in the Central and Western Gulf of Mexico planning areas as oil prices rebound. They also requested that the 5-year program define promising acreage in the Central and Western Gulf in an effort to reduce environmental impacts.
- Texas recommended adopting a tract selection presale process, stating that increases in the pace of development can be achieved without imposing the high costs and low returns to Federal and State Governments which are associated with areawide leasing.
- California generally endorsed the proposed presale process, but requested clarification of the following points: (1) the criteria that will be used to select blocks at the Call and Area Identification stages; (2) the type of information to be required for both positive and negative block nominations; and (3) the consultation and consensus procedures. With regard to the last point, they recommended that additional time be provided for States to solicit and address local government concerns. They also stated that it would be inappropriate to include blocks in the Area Identification stage if they were not included in the original Call area.
- Alaska recommended adopting a tract selection presale process and stated that if the focusing on promising acreage approach is adopted, blocks which receive no indication of industry interest should be eliminated from further consideration.

° State Agencies:

- New York Department of Environmental Conservation and Florida Department of Environmental Regulation endorsed the concept of focusing on promising acreage.
- Georgia Department of Natural Resources endorsed the concept of focusing on promising acreage but requested clarification concerning how areas would be studied and the process by which environmentally sensitive blocks would be identified.



- Texas General Land Office expressed opposition to the proposed presale process, stating that it would result in the offering of the entire Central and Western Gulf of Mexico planning areas, except for the Flower Garden Banks.
- California Coastal Commission commented that there is little difference between focusing on promising acreage and areawide leasing, and the size of lease sales will remain too large.
- California Department of Justice stated that the proposed presale process must be clarified so that it will be implemented consistently.
- Oregon Department of Geology and Mineral Industries stated that the proposed presale process should provide at least 90 days for review of the draft environmental impact statement (EIS).

° Local Governments:

- County of Volusia (FL) endorsed the concept of focusing on promising acreage and recommended that promising acreage be identified early in the presale process to eliminate conflicts.
- Ventura County (CA) endorsed the proposed presale process as preferable to areawide leasing.
- AMBAG (CA), San Luis Obispo County (CA), and City of San Diego (CA) commented that the proposed presale process does not precisely define the size of a sale and makes planning and environmental analysis extremely difficult.
- City of San Luis Obispo (CA) expressed oppositon to areawide leasing and stated that focusing on promising acreage would be acceptable if there is adequate State and local consultation, the Governor's presale comment period is expanded to 90 days, and special consideration is given to specific subareas.
- City of Newport Beach (CA) stated that the proposed presale process will result in the leasing of blocks determined by oil company preference.
- City of Laguna Beach (CA) commented that local governments should be directly involved in the presale process to determine the size of sales.
- Several local governments in California commented on this topic by noting the proposed presale process in resolutions stating general opposition to the Proposed Program. These include Mendocino County, Monterey County, Orange County, San Luis Obispo County, San Mateo County, and Santa Cruz County.
- North Slope Borough (AK) expressed support for the proposal to request more detailed information from industry or areas of interest prior to the Call for Information and Nominations and again after issuance of the draft EIS.

° Industry:

- The majority of commenters addressing this topic stated a general preference for areawide leasing and perceived focusing on promising acreage as a process which would limit exploration strategies and opportunities.
- API, Exxon, and Combustion Engineering urged that areawide leasing be retained in the Central and Western Gulf of Mexico planning areas.
- Unocal expressed support for areawide leasing in the Gulf of Mexico and Alaska OCS planning areas.
- AOGA, NOIA, Chevron, Conoco, Exxon, Texaco, and Zapata expressed general support for focusing on promising acreage.
- API, NOIA, and Exxon recommended that the proposed presale process incorporate the following provisions: encouragement of diverse, innovative approaches to leasing and development; prohibition of subarea deferrals without valid scientific or legal justification; consideration of previously deferred subareas as appropriate;

identification of the Call area as only a guideline for the information request; and consideration of expressions of interest in areas outside of the Call area guideline. API also suggested that MMS rely to a great extent on the petroleum industry to determine the most promising acreage for each sale.

- Exxon recommended that the proposed presale process employ a "flexible call for information" which would allow nominations outside a narrow initial Call area. They stated that such a concept would provide for consideration of all exploration theories while focusing necessary environmental and economic analyses on a relatively small sale area. They also recommended that only a brief supplemental environmental impact statement be prepared for sales offering blocks which previously have been analyzed and offered.
- BP Alaska, Standard, and AOGA recommended that industry be given the opportunity to request expansion of the proposed sale area as part of the Call process.
- Shell expressed opposition to focusing on promising acreage prior to the Call for Information and Nominations step for each lease sale.
- Commenters addressing this topic were unanimous in opposition to revising nomination procedures to request more detailed information from industry on areas of interest prior to the issuance of the Call and again after issuance of the draft EIS. Many cited their concerns about disclosure of proprietary data as the principal reason for objecting to the proposal.
- The great majority of commenters addressing this topic endorsed the recommendation that nomination procedures be revised to request more detailed information concerning negative nominations. Several recommended that negative nominations be required to be submitted without prior knowledge of the most recent expressions of industry interest.
- Amoco expressed skepticism concerning the proposal to revise negative nomination procedures, stating it would result in discounting unique company perceptions and strategies.
- Amoco, BP Alaska, and Phillips expressed opposition to announcing in the Federal Register the availability of the MMS proposed Call area for industry interest review prior to the issuance of the Call.
- Conoco endorsed the proposed Federal Register announcement of the Call area for industry interest review.
- Exxon and Tenneco expressed qualified support for the proposed Federal Register announcement of the Call area for industry interest review. Exxon recommended that the procedure be adopted informally on a sale-by-sale basis and information on company interest be withheld from public release prior to the Call for Information and Nominations. Tenneco recommended that industry interest information be withheld from public release for at least the term of the 5-year leasing program.

° Environmental and Other Organizations:

- NRDC recommended the use of a tract selection process because the areawide and focused approaches cause adverse economic impacts and are unpredictable and unsatisfactory for planning purposes.



- Maine Audubon Society requested clarification of the proposed presale process, stating that it is not clear if focusing on promising acreage will select tract sizes that are large enough to be economically viable yet small enough to be adequately assessed for environmental impact.
- Association for the Preservation of Cape Cod, Inc. stated that focused leasing is not very different from areawide leasing, which they oppose.
- Massachusetts Audubon Society expressed opposition to the proposed presale process, stating that it does not reduce the scale of lease sales enough to allow adequate assessment of environmental impacts.
- Friends of Canaveral (FL) recommended that lease sales focus on areas with greater resource potential to facilitate planning.
- Florida PIRG endorsed the concept of focusing on promising acreage, but requested clarification. They made the following specific recommendations concerning the process: (1) improve identification of areas of high industry interest so that a greater percentage of the area offered is actually leased; (2) consider areas of high environmental concern for deferral; and (3) define deferral areas before developing the EIS, and tailor the EIS to the focused area.
- Manasota 88 (FL) commented that the process of focusing on promising acreage appears to be without logic, since sale 94 in the Eastern Gulf of Mexico offered about 36 million acres, while the Call for Information and Nominations for Sale 91 in the Northern California planning area included only about 1.2 million acres.
- League of Women Voters of Ventura (CA) commented that the proposed presale process would not result in sales of reasonable size to decrease impacts and allow onshore infrastructure to keep pace with offshore development.
- League of Women Voters of Santa Barbara (CA) commented that no matter what presale process is employed, the result will be rapid offshore and onshore development in the Santa Barbara area.
- Sierra Club (Santa Lucia, Ca Chapter) commented that the proposed presale process would result in lease sale areas which are too large.
- Salinas (CA) Chamber of Commerce expressed opposition to areawide leasing.

° Private Citizens:

- Several commenters stated that the Proposed Program would feature sales offering areas which are too large.

6. THE PROPOSED MEANS OF PURSUING FLEXIBILITY IN THE NEW PROGRAM IN LIGHT OF NATIONAL ENERGY NEEDS AND UNCERTAINTY OVER FUTURE OIL AND GAS SUPPLIES AND PRICES; AND, IN PARTICULAR, THE POSSIBLE ECONOMIC CRITERIA FOR THE ACCELERATION PROVISION.

(1) FRONTIER EXPLORATION SALES

° Federal Agencies:

- EPA endorsed the concept of frontier exploration sales and recommended that such sales be scheduled in all planning areas where triennial leasing is proposed other than Southern California.
- NOAA commented that the uncertainty of frontier exploration sales could affect adversely the Environmental Studies program for Alaska planning areas. They also stated their intention to work closely with the MMS to

ensure that the 5-Year Environmental Studies Management Plan is designed to make sufficient preliminary data available prior to the Request for Interest for each sale.

° State Governors:

- Maine, New Hampshire, Massachusetts, Rhode Island, Connecticut, New Jersey, Delaware, Maryland, and North Carolina endorsed the scheduling of frontier exploration sales.
- Massachusetts recommended that States be notified when MMS issues a Request for Interest, and they requested that the interest level necessary to justify a sale be defined. They also requested that States be provided a summary of MMS/industry consultations.
- Alabama endorsed the concept of frontier exploration sales but requested increasing the number of such sales on the schedule.
- Oregon and Washington commented that the concept of frontier exploration sales confounds the intent of the OCS Lands Act, as amended, which calls for a precise description of timing and location.
- Alaska endorsed the frontier exploration sales proposed off Alaska and requested that such sales be scheduled in the St. George Basin and Norton Basin planning areas.

° State Agencies:

- New York Department of Environmental Conservation and Georgia Department of Natural Resources endorsed the concept of frontier exploration sales. The former also requested that a second request for industry interest be issued prior to the Proposed Notice of Sale.

° Local Governments:

- Bristol Bay Coastal Resource Service Area recommended that the Bering Sea OCS planning areas be designated for frontier exploration sales.

° Industry:

- Chevron endorsed the proposed frontier exploration sales.
- Shell expressed support for scheduling frontier exploration sales but objected to their tentative status and stated that the Request for Interest step is unnecessary. However, they recommended that if this step is adopted, it be reissued annually for areas in which industry interest has previously been found to be insufficient for proceeding with a sale.
- Exxon expressed concern that adding the Request for Interest step to the presale process may invite additional legal challenge. They recommended that industry interest instead be determined during annual review of the program.

° Environmental and Other Organizations:

- Massachusetts Audubon Society commented that frontier exploration sales are preferable to standard sales but stated that if such a sale is cancelled it should never be rescheduled.
- NRDC expressed opposition to the concept of frontier exploration sales, stating that their tentative status undermines State planning and MMS' commitment of money to environmental studies. They



recommended that these sales not be scheduled initially but added in formal revisions of the program should circumstances change to make leasing in frontier areas viable.

(ii) SUPPLEMENTAL SALES

° Federal Agencies:

- EPA recommended that information distribution and review/comment milestones be established relative to the Proposed Notice of Sale for a supplemental sale. They further stated that such milestones should allow adequate time to review concerns raised in the National Environmental Policy Act process for the purpose of restructuring the Proposed Notice of Sale.

° State Governors:

- Connecticut endorsed the concept of supplemental sales.
- Florida commented that supplemental sales must not be held until social, economic, and environmental factors are considered and consultation with State and local governments is conducted. They also stated that supplemental sales must not be added if they will conflict with the objectives of the 5-Year Environmental Studies Plan.
- Alabama endorsed the concept of supplemental sales and recommended increasing the number of such sales.
- California endorsed the concept of supplemental sales but stated that the regulatory authority for conducting such sales is questionable. They also recommended holding supplemental sales only after promulgating regulations pertaining to block selection criteria; provisions for State and local government consultation in accordance with section 19 of the OCS Lands Act, as amended; and provisions requiring unitization agreements for development of drainage and development tracts along with original discoveries.

- Alaska endorsed the proposed supplemental sales provided that the following conditions are met: the State and the public are allowed to comment prior to such a sale; the blocks proposed for sale were evaluated under the EIS alternative adopted; the State did not oppose leasing the proposed blocks in the presale planning process; and the proposed blocks would enhance drainage and development of the new discovery.

° State Agencies:

- Florida Coastal Resources Citizens Advisory Committee expressed opposition to supplemental sales.
- California State Water Resources Control Board commented that supplemental sales are unnecessary due to the heavy schedule of standard sales proposed.
- California Department of Justice stated that the concept of supplemental sales constitutes a violation of section 18(a) of the OCS Lands Act, as amended, since it fails to specify as precisely as possible those areas which will be offered for lease.

° Local Governments:

- City of Laguna Beach (CA) and Orange County (CA) recommended eliminating supplemental sales from the 5-year program.
- City of Newport Beach (CA), San Diego County (CA), City of San Luis Obispo (CA), and San Luis Obispo County (CA) expressed opposition to supplemental sales in combination with other features of the program. Newport Beach stated that supplemental sales in addition to standard sales would result in too much leasing. San Diego County stated that supplemental sales and the acceleration provision could result in continuous leasing in the Southern California planning area. San Luis Obispo County stated that supplemental sales and acceleration would overburden local planning agencies.
- Orange County (CA) noted supplemental sales in a resolution stating general opposition to the Proposed Program.

° Industry:

- API, NOIA, Chevron, and Shell specifically endorsed the proposed supplemental sales.
- AOGA expressed support for supplemental sales but recommended that the term "drainage and development blocks" be clearly defined to include all blocks located on a geologic structure in which a discovery has occurred.
- Exxon recommended that supplemental sales be broadened in scope to include unleased tracts on the same structure. They also stated that preparation of a brief supplemental EIS would be appropriate for blocks which previously have been addressed by a draft EIS.
- BP Alaska commented that blocks on which bids have been rejected in the previous year may not attract industry interest.

° Environmental and Other Organizations:

- NRDC stated that there is no reason for supplemental sales to offer blocks on which bids were rejected in the previous year, as one year is too short a time to acquire new information which might indicate that the value of such blocks has increased.
- Massachusetts Audubon Society expressed opposition to supplemental sales.
- Oceanic Society and League of Women Voters of Santa Barbara expressed concern about supplemental sales. The latter stated that such sales will serve to confound efforts to anticipate and properly plan for the impacts of OCS leasing.

° Private Citizens:

- A number of commenters expressed opposition to the proposed supplemental sales.

(iii) ACCELERATION

° Federal Agencies:

- DOD endorsed the proposed acceleration provision.



- DOE commented that the economic criteria proposed for the acceleration provision are inappropriate and/or unworkable. They stated that the Secretary of the Interior should have the authority to implement the acceleration provision when he determines that it would be in the Nation's best interest. They recommended that such a decision be made after appropriate consultation and careful consideration of the relationship of world oil production to world oil productive capability and the relationship of domestic oil imports to domestic oil consumption.
- EPA commented that modified lease diligence requirements might provide a better means for increasing oil and gas reserves than accelerated leasing. They suggested that, if adopted in the leasing program, acceleration be limited to high potential, high interest areas. They also made a specific recommendation against accelerated leasing in the North Aleutian Basin planning area.
- NOAA commented that accelerated leasing should be viewed with caution for the Naravin Basin, North Aleutian Basin and St. George Basin planning areas.

° State Governors:

- Massachusetts expressed concern that the acceleration provision may be implemented in a manner that circumvents statutorily mandated planning procedures and preempts adequate consultation with appropriate parties. They also expressed concern that acceleration will place excessive budget and staffing demands on affected regions.
- Rhode Island suggested that industry interest rankings be modified to show statistically significant differences among planning areas so that the appropriateness of acceleration in a particular planning area would be better indicated. They also requested better explanation of the International Energy Agency's oil sharing agreement and recommended that proposed criterion III be changed to read: "Major disruptions in foreign oil shipments."
- Connecticut endorsed the concept of accelerating lease sales and stated that economic indicators with "leading" characteristics should be the criteria on which acceleration decisions are based. They cited item VIII, projected oil prices, as the most promising such criterion and proposed that indices of lease sale bidding activity, exploration activity, and exploration budgets be considered as additional criteria.
- Maryland endorsed the concept of acceleration and stated a preference for acceleration over regularly scheduled biennial leasing.
- North Carolina recommended that specific guidelines and regulations be adopted before implementing the acceleration provision. They also commented that economic criteria proposed for consideration are actually short-term triggering conditions that would have little long-term relevancy.
- Florida commented that acceleration must not be implemented until social, economic, and environmental factors are considered and consultation with State and local governments is conducted. They also stated that acceleration must not conflict with the objectives of the 5-Year Environmental Studies Plan.
- Alabama endorsed the proposed acceleration provision and recommended that consideration be given to accelerating leasing in the Eastern Gulf of Mexico planning area in the event of a major discovery there.

- California recommended deleting the acceleration provision because: (1) the proposed resource triggers are redundant to the supplemental sales provision; (2) it runs counter to the planning needs of local governments; (3) the proposed economic emergency triggers are not justified; and (4) it is redundant to the Secretary's existing authority to make changes to the 5-year program through required annual reviews.
- Oregon and Washington expressed opposition to the acceleration provision on the grounds that it conflicts with the intent of the OCS Lands Act, as amended. Oregon also stated that acceleration of leasing in the Northern California planning area would be undesirable.
- Alaska stated that the criteria for accelerating leasing are not clear. They specifically recommended that the acceleration provision not be applied to the North Aleutian Basin planning area.

° State Agencies:

- Florida Coastal Resources Citizens Advisory Committee requested that leasing not be accelerated until specific guidelines for doing so have been developed and observed.
- California Coastal Commission, Department of Justice, State Water Resources Control Board, and 22 members of the California Legislature expressed opposition to the proposed acceleration provision.

° Local Governments:

- Ventura County (CA) recommended that specific acceleration criteria be defined and adopted and that sales be held no more than once every 2 years.
- City and County of San Francisco (CA) stated that the proposed acceleration provision excludes recognition of marine productivity and environmental sensitivity.
- The following California local governments expressed opposition to the proposed acceleration provision: Association of Monterey Bay Area Governments, Marin County, Orange County, San Diego County, Santa Barbara County, and the Cities of Huntington Beach, Monterey, Oceanside, Oxnard, Santa Barbara, Santa Monica, and Laguna Beach expressed opposition to the proposed acceleration provision.
- Several California local governments commented on this topic by noting the proposed acceleration provision in resolutions stating general opposition to the Proposed Program. These include Mendocino County, Monterey County, Orange County, San Luis Obispo County, San Mateo County, and Santa Cruz County.
- City of San Luis Obispo (CA) stated that acceleration should not be used to undermine triennial leasing and should be allowed only when certain criteria pertaining to onshore impacts are met.
- Bristol Bay Coastal Resource Service Area (AK) commented that the proposed acceleration provision conflicts with the OCS Lands Act, as amended, and they specifically expressed opposition to its implementation in the North Aleutian Basin planning area.

° Industry:

- API and NOIA expressed qualified support for the proposed acceleration provision but stated that the proposed acceleration criteria are inadequate. API recommended that acceleration be based simply on a finding by the Secretary that a new discovery in a planning area indicates that biennial leasing there is in the national interest. NOIA suggested that acceleration



criteria be based on new geologic information, revised industry interest, or a prospective ratio of domestic consumption forecasts to production levels within timeframes of 5, 10, and 15 years.
- Unocal commented that the Secretary should have the authority to accelerate leasing at his discretion, without carefully crafted conditions and criteria. They also expressed doubt concerning the effectiveness of the acceleration provision in dealing with a sudden, severe energy shortfall.
- Amoco recommended that flexibility be provided by scheduling annual contingency sales in all planning areas.
- Chevron, Murphy Oil, Phillips, Shell, and WOGA recommended expanding the scope of the acceleration provision. Chevron, Phillips, Shell, and WOGA expressed doubts about the usefulness of the proposed economic criteria. Phillips recommended that industry interest be the guiding criterion for acceleration, and Shell and WOGA cited positive exploration results and new or reinterpreted economic and geologic data for consideration. Chevron recommended that acceleration be implemented at the broad discretion of the Secretary.
- ARCO and Texaco endorsed the proposed acceleration provision and recommended that the guiding criteria be based on industry interest. ARCO suggested that industry interest be considered in conjunction with the proposed economic criteria, and Texaco suggested that industry interest be the sole criterion considered.
- Standard commented that acceleration of leasing in areas of promising discoveries would be necessary to maintain exploration momentum, and they stated that acceleration is preferable to supplemental sales as a means to make additional acreage available. They also questioned the usefulness of the proposed economic criteria.
- AOGA endorsed the concept of acceleration and recommended that it be guided by geologic criteria in addition to the economic criteria proposed.
- Conoco stated that the proposed economic criteria are very important to the program, but expressed doubt about the effectiveness of the acceleration provision in dealing with an energy emergency.
- Exxon commented that the acceleration provision may be a useful means of expediting OCS exploration and development under certain conditions, but it is not an adequate substitute for biennial leasing. They recommended that criteria based on geologic information such as a hydrocarbon show in a frontier area be considered in addition to economic and event criteria. They also recommended that decisions to accelerate not be limited to the annual program review.
- BP Alaska stated that if accelerated leasing is to have an impact on OCS development and production, it must be implemented in the immediate future. They also recommended that criteria for acceleration be expanded to include significant technical developments within a planning area, and they expressed doubt concerning the effectiveness of proposed economic criteria.
- Sun stated that it is doubtful that acceleration of leasing during a national emergency could have any useful impact.

° Environmental and Other Organizations:

- NRDC commented that acceleration of a lease sale must be considered a significant revision of the program and be subjected to required procedures. They also expressed doubt concerning the effectiveness of the provision and recommended filling the Strategic Petroleum Reserve as an alternative.

- Association for the Preservation of Cape Cod, Inc. and Massachusetts Audubon Society expressed opposition to the proposed acceleration provision.
- Sierra Club (Florida Chapter) stated that acceleration of a lease sale must be considered a significant revision to the program and be subjected to required procedures.
- Sierra Club (Santa Lucia, Ca. Chapter) and Leagues of Women Voters of Sacramento (CA) and Ventura (CA) stated that the proposed acceleration provision should not be implemented without congressional approval.
- Leagues of Women Voters of Santa Barbara (CA), Santa Cruz (CA), and Sonoma (CA) commented that the proposed acceleration provision would cause uncertainty and confound the planning efforts of local governments.
- Friends of the Earth (Northwest Office) stated that the proposed acceleration provision appears to circumvent the OCS Lands Act, as amended.

° Private Citizens:

- A number of commenters expressed opposition to the proposed acceleration provision.

B. <u>Summary of Comments Addressing Additional Pertinent Topics</u>

1. STATE AND LOCAL GOVERNMENT PARTICIPATION IN THE OCS LEASING PROGRAM.

- Most of the State Governors cited the importance of consultation and cooperation between State and Federal Government in developing the 5-year leasing program and conducting individual lease sales.
- Rhode Island requested full membership in both the North Atlantic and Mid-Atlantic Regional Technical Working Groups.
- Oregon requested establishment of a Regional Technical Working Group or subgroup for the Washington-Oregon planning area.
- California Coastal Commission and Department of Justice commented that the Proposed Program is not an adequate and dependable document for State and local government planning purposes.
- Several local governments in California addressed this issue by stating in resolutions expressing general opposition to the Proposed Program that local government concerns are not addressed by the program. These include Mendocino County, Monterey County, Orange County, San Luis Obispo County, San Mateo County, Santa Cruz County, and City of Torrance.
- City of Newport Beach (CA) stated that State and local governments do not have the staffing and financing necessary to fully participate in the leasing program.
- City of Huntington Beach (CA) stated that local government involvement in the planning and leasing process is critical to achieving balanced development.
- City of St. Paul (AK) recommended that there be closer interaction among industry, the Federal Government, and local governments affected by leasing and development.
- Leagues of Women Voters of Santa Barbara (CA) and Santa Cruz (CA) stressed the need for mechanisms to allow the public and State and local governments to participate in the review of OCS leasing issues.



2. ENERGY AND ECONOMIC SECURITY

- DOE stated that a viable, continuing OCS oil and gas leasing program is crucial to the national defense and economic well being.
- Alabama commented that an effective and environmentally sound OCS leasing program will provide partial relief for the Nation's future energy demands and is therefore vital to national security.
- South Carolina Joint Legislative Committee on Energy stated that the OCS leasing program will give the Nation a more positive assurance of future energy supply and will reduce the Nation's balance of trade deficit.
- City of Eureka (CA) stated that an effective and environmentally sound OCS leasing program will provide national security and economic well being.
- Several commenters, including numerous State and local highway users associations, stated that the OCS leasing program is vital to the Nation's future energy security and economic well being.
- National Alliance of Senior Citizens and Florida Federation of Women's Clubs stressed the need for a viable OCS leasing program to ensure the Nation's energy security.
- A number of commenters stated that the OCS leasing program will contribute to the Nation's energy security and economic welfare.

3. LOW OIL PRICES AND THE PROGRAM'S ECONOMIC ANALYSIS

- DOE suggested widening the range of oil prices used in the program's economic analysis to include a lower case which takes actual price declines into account.
- North Carolina and Oregon recommended redoing the program's economic analysis to reflect actual oil price declines.
- California Coastal Commission recommended redoing the program's economic analysis using an oil price range of \$5 to \$29 per barrel, and California Department of Justice recommended using an oil price range of less than \$10 to \$29 per barrel.
- AMBAG (CA) commented that the price range of \$19-\$29 per barrel in the Proposed Program undermines the program's cost/benefit analysis and estimates of resources worth recovering at lower prices.
- Louisiana Association of Business and Industry recommended redoing the program's economic analysis using a lower oil price range and suggested that lower oil prices possibly can make some planning areas have a comparably higher economic value than they would at higher prices.
- Get Oil Out, Inc. stated that the Proposed Program fails to address the need for considering prevailing economics when OCS leases are offered in sales.
- NRDC commented that the Proposed Program is based on a seriously flawed economic analysis which should be completely redone in light of actual low oil prices.

4. SOCIAL COST ANALYSIS

- Massachusetts stated that the program's oil spill impact analysis should consider and assess chronic low level impacts of small oil spills.
- California stated that the program's social cost analysis is deficient and should address the following factors:
  -- air quality impacts with respect to their effect on State and onshore oil and gas production;

-- indirect air quality impacts, including potential EPA economic sanctions, reduced availability of emission offsets, and reductions of production onshore and in State waters;
-- infrastructure costs not recovered through user fees and the limits on revenue collection imposed by Propositions 13 and 14;
-- planning costs for local governments in the Santa Maria Basin/Santa Barbara Channel area; and
-- the lack of authority of State and local governments to tax the facilities located in the OCS.

- Oregon and Washington commented that the Proposed Program underestimates social costs for the Washington-Oregon planning area. Oregon cited incidents of high social cost which have occurred in the area and pointed out that such costs may be borne locally. Washington stated that there have been no studies on which to base a finding that social costs to the area would be negligible.
- AMBAG (CA) faulted the Proposed Program's social cost analysis for making the following assumptions:
  -- oil prices would range between $19 and $29 per barrel;
  -- economic value cannot be established for biological and ecological resources;
  -- a particular locale's tourism losses would largely be offset by gains at other locales;
  -- oil spills would be the only factor affecting tourism;
  -- infrastructure costs could reasonably be defrayed by user fees; and
  -- air pollution would not have a cumulative impact on costs.
- City and County of San Francisco (CA) commented that social costs for California OCS planning areas are underestimated.
- Santa Cruz County (CA) stated that the Proposed Program does not represent accurately the economic value of coastal and offshore resources, and they took issue with the assumption that biological resources cannot be accurately assigned a monetary value.
- Maine Audubon Society commented that the social costs of drilling in the Gulf of Maine outweigh the benefits.
- Washington Environmental Council stated that projected social costs for the Washington-Oregon planning area are understated.
- NRDC conveyed the following criticisms of the social cost analysis:
  -- social costs should not be assumed always to be greater if oil comes ashore;
  -- domestic production should not be assumed to replace foreign oil barrel-for-barrel;
  -- drilling muds and cuttings should not be assumed to be benign to the marine environment;
  -- tourism losses should not be totally excluded;
  -- infrastructure costs in additon to the cost of planning should be considered;
  -- the valuation of wetland losses should be higher;
  -- subsistence values should be higher;
  -- sizes of oil spills assumed should be higher; and
  -- social costs of leasing the North Aleutian Basin planning area should be properly assessed.



5. MARINE PRODUCTIVITY AND ENVIRONMENTAL SENSITIVITY ANALYSIS

- Massachusetts stated that it is not appropriate to assume for the Georges Bank area that marine habitats have a low sensitivity to oil or will not be affected by a spill because oil will not reach the bottom.
- Georgia Department of Natural Resources recommended that hard bottom areas further be analyzed and studied. They also stated that since sensitive biota such as turtles, birds, and juvenile fish are associated with hard bottoms, the overall community should be valued as a whole in the calculations of sensitivity coefficients for this bottom type.
- California Coastal Commission faulted the Proposed Program analysis for assigning the same marine habitat score for all three California OCS planning areas.
- California Department of Justice commented that the Proposed Program fails to respond to EPA's criticisms of the marine productivity/environmental sensitivity analysis in the Draft Proposed program (March 1985). They also faulted the assumption that drilling muds, cuttings, and formation fluids have no adverse impacts on the marine environment.
- NRDC disputed the conclusions of the analysis with respect to the effects of drilling muds and cuttings and produced waters.

6. EQUITABLE SHARING OF DEVELOPMENTAL BENEFITS AND ENVIRONMENTAL RISKS

- Connecticut expressed support for the concept of revenue sharing to provide funding in support of coastal zone management activities and OCS participation
- Alabama and Texas called for efficient equitable sharing of revenues under section 8(g) of the OCS Lands Act, as amended, and cited drainage of State oil and gas resources as a concern.
- Louisiana stated that the proposed leasing program does not treat planning areas with high resource potential and high industry interest equally, and they called for more sales outside Central and Western Gulf of Mexico, especially in California OCS planning areas.
- Virginia Council on the Environment expressed support for sharing OCS revenue with coastal States.
- Texas General Land Office stated that royalty rates for Federal leases adjacent to State leases should be made comparable to the rates for State leases in order to eliminate an incentive for Federal lessees to drain common structures.
- A letter signed by 22 members of the California Legislature stated that California produces a large amount of OCS oil and gas and therefore should have certain areas placed off limits to leasing. California Lieutenant Governor made the same comment.
- County of San Luis Obispo (CA) expressed support for sharing OCS revenue with affected State and local governments under the Proposed Program.
- City and County of San Francisco (CA) commented that California would bear an uneven burden of environmental risk under the Proposed Program.
- Several California local governments commented on this topic by stating in resolutions that the Proposed Program fails to consider equitable sharing of developmental benefits and environmental risks

among the various regions of the United States. These include Mendocino County, Monterey County, San Luis Obispo County, San Mateo County, and Santa Cruz County.

- North Slope Borough (AK) expressed support for sharing OCS revenue with local governments.
- Louisiana Association of Business and Industry stated that the Proposed Program fosters dependence on the Gulf of Mexico's reserves while deferring exploration opportunities in other planning areas.
- Sierra Club (Santa Lucia, Ca. Chapter) stated that it is unfair for the Proposed Program to subject California to the economic and environmental risks of OCS leasing so that other parts of the country can squander energy supplies.
- Friends of the Sea Otter stated that California already provides a great amount of oil and gas and is overburdened by development of existing leases.

7. FAIR MARKET VALUE

- Florida cited the results of Sales 79 and 94 and stated that areawide leasing results in insufficient competition to assure the return of fair market value for lands leased.
- Texas stated that the Federal Government should not allow the rights to OCS oil and gas to be leased for less than fair market value.
- California recommended retention of the current minimum bid at least for all blocks leased within the OCS area defined by section 8(g) of the OCS Lands Act, as amended. They also stated that the Proposed Program does not contain sufficient information to review the current procedures for assuring receipt of fair market value for lands leased.
- Texas General Land Office stated that fair market value will not be received for leases unless a nomination process is reinstituted to foster competition.
- California Department of Justice commented that receipt of fair market value should be accomplished by retaining the current minimum bid and greatly reducing the amount of acreage offered.
- A letter signed by 22 members of the California legislature commented that the Proposed Program may result in the receipt of much less than fair market value for lands leased. California's Lieutenant Governor made the same comment.
- Volusia County (FL) commented that the presale process of focusing on promising acreage should encourage competition and the receipt of fair market value for lands leased.
- Santa Cruz County (CA) stated that current procedures will result in the receipt of much less than fair market value.
- Chevron stated that the Proposed Program's procedures governing fair market value are appropriate.
- API commented that anticipated lower bids should not serve to delay or halt OCS leasing, because that ultimately would result in more expense to consumers.
- Exxon stated that the current minimum bid is too high.



- API, IADC, Shell and Standard recommended modifications to the leasing program which would provide financial incentive for exploration when low prices prevail. Such modifications would entail lowering the minimum bid, using alternative bidding systems, and providing tax credits.
- Phillips and Unocal commented that the minimum bid should be modified to reflect existing low oil and gas prices. Phillips also commented in favor of reducing royalty and rental fees and increasing the lease term.
- Several companies recommended reducing the minimum bid to specific levels: Amoco recommended $25 for leases in waters deeper than 400 m and $50 in waters less than 400 m; Pogo, Shell, and Tenneco suggested $25 for frontier areas; and Texaco recommended $25 to $50 and a term of 10 years for all leases.
- ARCO and Conoco commented that abolishing the current minimum bid would be appropriate. ARCO expressed support for formulating a sale-specific minimum bid, and Conoco stated that a minimum bid requirement is not appropriate under current prices.
- BP Alaska recommended changing the terms for leasing Alaska OCS planning areas. Modifications would include longer primary terms with work commitment provisions, larger lease blocks, and lower minimum bids and royalty rates.
- Standard recommended changing the terms for leasing off North Alaska and in water depths exceeding 600 feet. Such modification would entail sliding scale tax credits for exploration and production activities.
- NRDC stated that procedures for assuring receipt of fair market value should be modified as recommended by General Accounting Office Reports RCED-85-9, RCED-85-68, and RCED-86-78BR. They also commented against reducing the minimum bid.
- Association for the Preservation of Cape Cod, Inc. and Manasota 88 (FL) commented that OCS oil and gas leasing should not be conducted in view of existing low prices and their effect on the value received for leases.
- Florida PIRG commented that extensive focusing of acreage offered in lease sales would encourage competition and assure receipt of fair market value.
- Get Oil Out, Inc., Save the Redwoods League, Sierra Club (Santa Lucia Chapter), and Clairemont Mesa Planning Committee commented that OCS oil and gas leasing should not be conducted in view of existing low prices and their effect on the value received for leases.
- Several commenters stated that fair market value would not be received for leases offered while oil and gas prices are low.

8. OTHER ISSUES

- The Governors of Maine and Massachusetts commented that required budget and staffing information was not included in the Proposed Program. They specifically expressed concern that sales are proposed in the North Atlantic but the Atlantic Region Office of the MMS is presently without operations staff.
- The Governors of Maine, New Hampshire and Connecticut requested that the 5-year program address joint planning and management of Georges Bank resources by the United States and Canada.
- Several commenters expressed concern that the Proposed Program does not reflect a full and proper balance between the potential for environmental damage, the potential for the discovery of oil and gas, and the potential for adverse impact on the coastal zone.

# APPENDIX C

## LAWS, GOALS, POLICIES, AND COASTAL ZONE MANAGEMENT PROGRAMS OF AFFECTED STATES

## CONTENTS





# LAWS, GOALS, POLICIES, AND COASTAL ZONE MANAGEMENT PROGRAMS OF AFFECTED STATES

## I. Introduction

Section 18 of the Outer Continental Shelf (OCS) Lands Act, as amended, requires the Secretary of the Interior to consider several factors in preparing and maintaining the 5-Year OCS Oil and Gas Leasing Program. These factors include: 1) the laws, goals, and policies of affected States which the Governors of those States specifically identify as relevant to the leasing program [18(a)(2)(F)]; and 2) the coastal zone management programs being developed or administered by affected States [18(f)(5)]. The Secretary has considered the relevant issues identified at each stage in the development of the 5-year program.

The Governors of affected States first cited their coastal zone management programs and identified relevant laws, goals, and policies in response to a July 5, 1984, letter from the Secretary soliciting such information. The information was presented in Appendix C of the Draft Proposed Program (March 1985) and is incorporated herein by reference. The Secretary's letter dated March 19, 1985, transmitted the Draft Proposed Program to the Governor of each affected State and requested comments in preparation of the next stage, the Proposed Program. Relevant information which the Governors submitted in response to this request was presented in Appendix C of the Proposed Program (February 1986) and is incorporated herein by reference. The Secretary's letter dated February 4, 1986, transmitted the Proposed Program to the Governors and requested comments to be considered in developing the Proposed Final Program. Thirteen responses identified relevant laws, goals, and policies or cited coastal zone management programs for the Secretary's consideration.

## II. Laws, Goals, and Policies Identified by Governors in Response to the Proposed Program (February 1986)

These matters have been presented to the Secretary as follows (comments are those of the Governor unless otherwise indicated):

- Connecticut: "Connecticut also continues to support the concept of consistency review for lease sales and their potential impacts upon coastal management programs."

- New Jersey: "New Jersey maintains its policy of support for the exploration and production of oil and gas resources from the Outer Continental Shelf as long as the activities can be structured in a manner consistent with sound environmental practices necessary for the protection of our coastal tourism industry and the State's $1 billion commercial and recreation fishing industry."

  "For the past five years the State has maintained a position on Mid-Atlantic lease sales of excluding tracts of low industry interest within 50 miles of our coast. The basis of this recommendation is found in a report prepared for the Department of Environmental Protection by the Center for Coastal and Environmental Studies within Rutgers University. The report, The Impact of OCS Lease Sale 76 on the Tourism and Fishing Industries of New Jersey (dated 3/2/82) cites the potential environmental and economic damage to our coastal tourism and fishing industries from a major oil spill, the negative visual impacts, and the potential spatial conflicts with our inshore coastal fisheries."

- Delaware: "Delaware's position on deferral or deletion of a zone 15 miles from our shores derived from an analysis of OCS Sale No. 59, when it was suggested that the first three tiers of OCS blocks nearest the three-mile limit be considered for joint state-federal control because of the concentration in that zone of shipping, sport and commercial fishing, and tourism that could conflict with exploration activities. Assurances derived from joint control might provide an option to the arbitrary prohibition of leasing."

- Maryland: "The State of Maryland has always been in favor of offshore federal leasing provided it is done with proper environmental safeguards and with an opportunity for all potentially affected interests to evaluate the options on a timely basis prior to each sale. I believe this latter concern cannot always be addressed when the areawide leasing system is used."

- Virginia: "The Commonwealth of Virginia's position, since the inception of the Middle Atlantic OCS Leasing Program, has been to support OCS activities, provided they are consistent with Virginia's environmental policies and goals. Virginia has favored deletion from lease sales of those tracts within 50 miles of its Coast and in offshore canyon heads, to protect coastal and nearshore resources."

- Florida: "As we have stated on previous occasions, the Department of Environmental Regulation supports the State position favoring oil and gas exploration of the Outer Continental Shelf, as long as the program is conducted with sufficient environmental safeguards. DER is specifically concerned with the protection of marine resources--particularly benthic habitat and associated communities--and water quality, which are interrelated. Because leasing and exploration is inescapably tied to eventual production and transportation, we must also view areas proposed for leasing in terms of associated landside impacts. For these reasons we are particularly concerned with the opening of areas adjacent to southernmost Florida nearshore anywhere along Florida's coast." (The source of this comment is a Florida Department of Environmental Regulation letter enclosed with Governor Bob Graham's comments on the Proposed Program.)

- Alabama: "The position of the State of Alabama is that all blocks in Alabama's 8(g) area are assumed to contain common pools/common structures unless proven otherwise by geological and engineering information obtained by the drilling of wells. Considering the very interpretive nature of geophysical analyses we feel that common pool/common structure determinations made in the new 5-year program should be consistent with Alabama's position on this issue."

  "The potential for drainage of Alabama's hydrocarbons as a result of production from wells in Federal waters is a concern to the State of Alabama. Minerals Management Service should require as a lease stipulation for the new 5-year program and the present 5-year program that no wells be drilled less than 1320 feet from the Alabama state line on any tract in Alabama's 8(g) area unless a fair and equitable unitization agreement has been reached between Minerals Management Service and the State of Alabama. This stipulation would prevent drainage and be consistent with Alabama State Oil and Gas Board Rules and Regulations."



  "The potential for harm to Alabama's coastal environments by oil and gas related activities in federal waters is a concern of the State of Alabama. Minerals Management Service should require as a lease stipulation for the new 5-year program and the present 5-year program that all wells drilled on federal tracts in Alabama's 8(g) area be drilled with regard to the same environmental and water quality regulations as wells drilled on adjacent state tracts. This stipulation would insure the protection of the sensitive ecosystems in Alabama state waters. All activities in the area of offshore Alabama relating to or resulting from federal OCS leasing, drilling, and production activities proposed for the new 5-year program and under the present 5-year program should be consistent with the laws, rules and regulations of the State of Alabama. Any exploration or development scenarios in the area of offshore Alabama whether under the new 5-year program or the present 5-year program should be compatible with Alabama's Coastal Zone Management Program policies and consistency certification requirements."

- Lousiana: "The state's coastal zone management program requires mitigation for the unavoidable impacts of oil and gas development on wetlands; the Federal program should carry a similar obligation."

- Texas: "The General Land Office remains concerned about the disparity in oil and gas lease royalty rates along the offshore Texas-federal boundary. The leasing of federal tracts adjacent to Texas should be at comparable royalty rates to those received by the state to prevent an unfair incentive for federal lessees to drain common hydrocarbon-bearing structures. I believe this is a priority matter for the Department's attention and that it should be addressed in both the upcoming sale in the Western Gulf (Sale 105) and the Proposed 5-Year Program." (The source of this comment is a Texas General Land Office letter enclosed with Governor Mark White's comments on the Proposed Program.)

- California: "Two State laws, goals, or policies relevant to the section 18(a)(2) balancing criteria were identified: Areas of Special Biological Significance (ASBS), and oil and gas sanctuaries.

  The Proposed Program should be modified to include deferrals of all tracts within 6 miles of the seaward boundary of each ASBS. The ASBS contain certain unique biological communities that because of their value or fragility, deserve special protection that consists of the preservation and maintenance of natural water conditions to the extent practicable. The State Water Resources Control Board is the responsible agency for designation of areas for ASBS status. This Agency has determined 6 miles to be the minimum required buffer zone, consistent with prior requests by California in past lease sales, such as for the subarea deferral for the Mugu Lagoon to Latigo Point ASBS which was requested by Governor Deukmejian and agreed to by Interior for deletion from Lease Sale 80.

  Although some of the ASBS are protected by the subarea deferrals of the Proposed Program, all 34 ASBS should be protected . . . ."

  "All tracts within 3 miles of the seaward boundary of the California oil and gas sanctuaries should be included in subarea deferrals. These sanctuaries are established in sections 6871.1 and 6871.2 of the California Public Resources Code, and prohibit the extraction of oil and gas from State owned tide and submerged lands. These sanctuaries protect significant biological resources, prime commercial fishery grounds, several of the State seashores identified by the Department of Parks and Recreation, and other public recreation areas."

"The Proposed Program documents do not address several State and local laws, goals, and policies identified by Governor Deukmejian as relevant matters for consideration in the new 5-Year Leasing Program:

1) California Coastal Act and Coastal Plan;

2) Local Coastal Programs and General Plan elements;

3) State Implementation Plan for the Attainment and Maintenance of Ambient Air Quality Standards;

4) Local air quality plans; and

5) State and local policies favoring the use of pipelines rather than tankers for crude oil transportation.

The relevant aspects of these laws, goals and policies were identified by the Secretary of Environmental Affairs on behalf of the Governor, in the September 1984 letter, and by State and local agencies in the attachments to the September 1984 letter, June 1985 letter, and this letter. In addition, in the attachments to this letter, the State Water Resources Control Board and North Coast Regional Water Quality Board have identified two further plans of relevance to the new 5-Year Leasing Program: Water Quality Control Plan of Ocean Waters of California and the Regional Water Quality Control Plans."

[Briefly summarized, California's relevant laws, goals and policies relate to public access, recreation, the marine environment, land resources, general coastal development, and location and development of oil and gas industry facilities. Oil and gas industry facilities are encouraged to be located or expanded within existing sites; multicompany use of existing and new tanker facilities is encouraged; offshore platforms are required to locate where they will not pose hazards to vessel traffic; and the location of liquified natural gas facilities is required to be determined by the Public Utilities Code. New or expanded refineries or petrochemical facilities are permitted in areas designated as air quality maintenance areas by the State Air Resources Board and in areas where coastal resources would be adversely affected only if the negative impacts of the project on air quality are offset by reductions in emissions in the area by the users of the fuels, or, in the case of an expansion of an existing site, total site emission levels do not increase. The State Implementation Plan for the Attainment and Maintenance of Ambient Air Quality Standards prescribes limits and allocations of both onshore and offshore emissions to meet U.S. Environmental Protection Agency requirements. The State's Water Quality Plan for Ocean Waters sets forth water quality objectives and effluent requirements and asserts, "If a discharge outside the territorial waters of the State could affect the quality of the waters of the State, the discharge may be regulated to assure no violation of the Ocean Plan will occur in ocean waters."]



° Oregon: ". . . leasing activities in specific areas requested for deletion will not meet the requirements of the Oregon Coastal Management Program, including Statewide Planning Goal 19, Ocean Resources;"

". . . the provisions for technical consultation with Oregon and Washington will not be adequate to meet the needs of State coastal managers to fully plan for lease sales which would result in offshore exploration and development proposals consistent with Oregon's Coastal Management Program."

[Briefly summarized, Goal 19 calls for Federal, State and local governments to compile information necessary to assess the impacts of proposed OCS activities on the ocean and coastal environment. The policy specifically sets goals to study and maintain fisheries and other biological resources, safe ports and navigation routes, and quality aesthetic and recreational coastal areas. Goal 19 also requires that contingency plans and emergency procedures be established before issuing permits for OCS development.]

° Washington: "Under Washington's 1976 federally approved coastal zone management program, the entire coast - from Cape Flattery to Cape Disappointment, has been designated a 'shoreline of state-wide significance.' Special management criteria apply to these shorelines to ensure, among other things, the long-term public benefit and the protection of the coast's resources and ecology.

The State of Washington seriously questions the need for a planning area of the size which has been proposed, for it conflicts with the previously stated objectives of Washington's coastal zone management program."

° Alaska: "The state has a long-standing position that a maximum of 12 sales should be scheduled for any five-year period and that a maximum of three sales should occur in any one year."

"The state has clearly established its position opposing leasing in the NAB [North Aleutian Basin] until at least 1994."

III. Coastal Zone Management

State coastal zone management programs are prepared and approved pursuant to procedures and standards established by the Federal Coastal Zone Management Act (CZMA). Individual State programs vary in several respects. Some States have passed comprehensive State coastal management laws and their programs are based on license, permit, or certification procedures pursuant to these laws. A larger number of States simply have relied on previously existing authorities; a system generally identified as networking. Executive Orders issued by the Governors or a series of interagency agreements are often used to define specific networking requirements.

State programs are most commonly administered through specially created coastal commissions or by chief executive officers of some State department or agency designated as responsible for program implementation. Some States implement most program authorities at the State level while other States allocate substantial authority to local governments with some limitations and oversight requirements reserved to the States.

Section 18 of the Outer Continental Shelf Lands Act (OCSLA) establishes the basic standards and procedures for preparation of the 5-year oil and gas leasing program. Several subparts of this section require consideration of coastal resources and coastal zone management (CZM) programs as part of this process.

- Section 18(a)(1) requires consideration of "the potential impact of oil and gas exploration on other resource values of the outer Continental Shelf and the marine, <u>coastal</u>, and human environments" (emphasis added).
- Section 18(a)(2)(F) requires consideration of "laws, goals, and policies of affected States which have been specifically identified by the Governors . . . ."
- Section 18(a)(3) requires consideration of the proper balance between the potential for oil and gas discovery and "the potential for adverse impact on the <u>coastal zone</u>" (emphasis added).
- Section 18(f)(5) requires the establishment of regulations and procedures for "consideration of the <u>coastal zone management program</u> being developed or administered by an affected coastal State . . ." (emphasis added).

Applicable laws and implementing Federal regulations for the OCS oil and gas leasing, exploration, and development program are adequate to assure the required consideration of the views of coastal States. These laws and regulations establish a phased decisionmaking process which has been reviewed at several levels of the judicial system and has been fully upheld.

The first basic step in the phased process is development of the 5-year OCS Oil and Gas Leasing Program through three stages. The Draft Proposed Program elicited comments on coastal zone management issues which were analyzed and considered in developing the Proposed Program. Publication of the Proposed Program provided affected States another opportunity to comment on coastal issues. All of these comments have been considered by the Secretary in the decision process for the Proposed Final Program.

The second basic step in the phased decisionmaking process involves development of plans for the conduct of individual lease sales. Lease sales are conducted in accordance with an established multistage process, an outline of which is presented in Appendix L. The outline provides a brief description of each stage and indicates those stages at which coastal zone management issues are considered. It can be seen that throughout the 2-year presale process, from the Call for Information and Nominations to actual lease issuance, there are several specific opportunities for identifying and resolving such issues.

The third basic step in the overall phased decisionmaking process is the approval of exploration plans. Exploration plans and accompanying environmental reports must be provided to each affected State. If the State has an approved CZM program, the exploration plan must receive a consistency concurrence from the State, pursuant to section 307(c)(3) of the CZMA. This is the earliest stage in the overall process where a sufficient amount of specific information is available for a conclusive consistency test. The Conference Committee report on this provision states that section 307(c)(3)(B) ". . . specifically applies the consistency requirement to the basic steps of the OCS leasing process--namely, the exploration, development, and production plans submitted to the Secretary of the Interior. This provision will satisfy State needs for complete information on a timely basis, about details of the oil industry's offshore plans."



The fourth basic step of the OCS decisionmaking process is the approval of development and production plans (or Development Operations Coordination Documents in the Central and Western Gulf of Mexico planning areas). It is not until after this stage that the most significant oil and gas activities in terms of potential environmental effects take place. Earlier exploration activities have little potential for environmental effects and are short-lived. Developmental and production activities are also the most difficult to predict at the lease sale stage. Again, section 307(c)(3) of the CZMA provides for State concurrence in a certification of consistency before any Federal permits may be granted. Additionally, under section 19 of the OCSLA, Governors of all affected States may submit comments on the size, timing, or location of proposed oil and gas development plans. The Secretary, as already noted, is required to accept these comments if he finds that they provide for a reasonable balance between the national interest and the well-being of the citizens of the affected States.

It is essential to recognize that throughout these steps no OCS oil and gas operations capable of affecting coastal resources may be approved unless they: (a) are found to be consistent by the State; (b) are conclusively presumed to be consistent because the State has not dissented within 6 months of submission of an OCS plan; or (c) are found by the Secretary of Commerce to meet a test related to objectives and purposes of the CZMA and/or national security objectives.

Despite the wide variations in coastal program authorities and implementation systems, State coastal programs tend to be very much alike in how they interact with the OCS program. States have direct authority over air, water, and land uses within State territorial waters and adjacent uplands defined as being part of the coastal zone. Pursuant to coastal program authorities, States control site approvals and operating standards for coastally sited OCS offshore support and production delivery and processing facilities. States do not have any direct jurisdiction or authority, however, over operations on the OCS. Under the CZMA, States do have authority, as noted above, to review OCS exploration plans and development and production plans. No license or permit for any activity described in detail in such plans may receive Federal approval unless States confirm a certification of consistency with State coastal policies or consistency is conclusively presumed upon failure by the State to meet certain standards for timely consistency review. An adverse finding by a State also may be appealed to the Secretary of Commerce.

The authorities contained in coastal programs are applicable to very specific land and water uses and potential impacts which do not take place prior to exploration and development and production operations. There are no States with policies which categorically oppose OCS development. This would not be appropriate as the CZMA contains several sections which require the States to consider national interests and energy self-sufficiency policies in program development. The size, timing, and location questions which can be addressed within the general planning area level of analysis at the 5-year program stage of OCS activity are not directly addressed by the more specific land and water use regulatory schemes of the CZM programs. The CZM programs are inherently more directly applicable to the decisions and activities of exploration and development as well as being directly required to apply at these later stages of the OCS process.

## IV. <u>Status of State Coastal Zone Management Programs of Affected States</u>

The following list shows the current status of CZM programs of affected States. The new 5-year program final Environmental Impact Statement will contain a brief characterization of each of these State CZM plans.

| State | Actual or Estimated Federal Approval Date By Fiscal Year (ends 9/30) | Comments and Status |
|---|---|---|
| Washington | 1976 | Approved |
| Oregon | 1977 | Approved |
| California | 1978 | Approved |
| Massachusetts | 1978 | Approved |
| Rhode Island | 1978 | Approved |
| North Carolina | 1978 | Approved |
| Maine | 1978 | Approved |
| Maryland | 1978 | Approved |
| New Jersey (Bay and Ocean Shore Segment) | 1978 | Approved |
| Alaska | 1979 | Approved |
| Delaware | 1979 | Approved |
| Alabama | 1979 | Approved |
| South Carolina | 1979 | Approved |
| Louisiana | 1980 | Approved |
| Mississippi | 1980 | Approved |
| Connecticut | 1980 | Approved |
| Pennsylvania | 1980 | Approved |
| New Jersey (Remaining Section) | 1980 | Approved |
| Florida | 1981 | Approved |
| New Hampshire (Ocean and Harbor Segment) | 1982 | Approved |
| New York | 1982 | Approved |
| Virginia | 1986 | Approved |
| Georgia | | Non-participating |
| Texas | | Non-participating |

# APPENDIX D

# INTEREST OF POTENTIAL OIL AND GAS PRODUCERS

# Interest of Potential Oil and Gas Producers

This is an analysis of industry's interest in exploration and development and of industry's assessment of hydrocarbon potential. The analysis is based on information submitted by companies in response to a February 7, 1986, Federal Register Notice (51 FR 4816) request.

## Background

The Minerals Management Service (MMS) made two earlier requests for industry to rank planning areas for interest and potential. The initial request for rankings was published in a Federal Register Notice (49 FR 28332) on July 11, 1984. The Notice requested companies to rank 24 planning areas. Eighteen companies provided rankings: 11 companies provided full rankings of interest and potential (BelNorth, ARCO, Chevron, Elf Aquitaine, Conoco, Union Oil of California, Phillips, Amoco, Shell, Sohio, and Exxon); and 7 companies provided partial rankings (BP Alaska, Texas Gas Exploration, Pennzoil, Gulf, Monsanto, Mobil, and Union Texas Petroleum).

In a March 22, 1985, Federal Register Notice (50 FR 11585), MMS issued a second request for industry respondents in particular to rank all planning areas of the Outer Continental Shelf (OCS). This second request was needed because the March 1985 Draft Proposed Program divided the OCS into 26 planning areas from the 24 planning areas used at the time of the initial Federal Register Notice. Planning areas offshore California were reconfigured from two (Southern California and Central/Northern California) to three (Southern California, Central California, and Northern California). The southern part of the South Atlantic planning area was extended to include the OCS off south Florida and designated the Straits of Florida planning area. Companies were requested to submit separate rankings of planning areas based on (1) hydrocarbon potential; and (2) exploration and development interest.

In order to encourage the frankest response, a Federal Register Notice (50 FR 20140) on May 14, 1985, extended the period of confidentiality for privileged or proprietary data submitted in response to the request for comments on the Draft Proposed Program. Each respondent's ranking, upon request, is being treated as confidential privileged or proprietary data for a period of 5 years after final approval of the new 5-year program. Summaries of rankings prepared by MMS and the names of respondents submitting rankings are not being treated as confidential information.

New rankings were received from nine companies in response to the March 22, 1985, Federal Register Notice. Six companies submitted full rankings in both categories of interest and potential. Three companies submitted partial rankings in both categories. Full rankings were submitted by Amoco, Shell, Chevron, Exxon, Mobil, and Sohio. Tenneco, BP Alaska, and Union Texas Petroleum submitted partial rankings.

In light of the removal from leasing consideration of acreage from the planning areas resulting from the 15 subarea deferrals proposed by the Secretary, the February 7, 1986, Federal Register Notice requested industry respondents in particular to re-rank all 26 planning areas of the OCS. Again, separate rankings were requested for: (1) hydrocarbon potential; and (2) exploration and development interest. The Notice requested that rankings be based on estimates of resources expected to be unleased as of January 1987. Industry respondents were also asked to indicate those areas in which they intend to



operate or have serious interest in leasing or operating. Respondents were also asked to indicate whether the deferral of leasing in any of the 13 subareas highlighted for further analysis and comment would result in a significant decrease in the rank of the affected planning area(s).

The MMS reiterated its intent to provide upon request confidential treatment of privileged or proprietary information from the time of receipt by MMS until 5 years after final approval of the next leasing program. Summaries of rankings submitted to MMS, the names of respondents submitting rankings, and comments other than rankings will not be treated as confidential information.

## Rankings

Thirteen companies submitted rankings of interest; and twelve companies submitted rankings of hydrocarbon potential. Companies included Amoco, ARCO, BP Alaska, Chevron, Conoco, Exxon, Mobil, Murphy Oil/ODECO, Shell, Sohio, Tenneco, Texaco, and Unocal. Ten companies submitted complete rankings for interest; and three submitted partial rankings. For interest, the Straits of Florida planning area was ranked by 10 companies; Northern, Central, and Southern California, and Chukchi Sea each were ranked by 13 companies; and all other planning areas each were ranked by 12 companies. Nine companies submitted complete rankings for hydrocarbon potential; three submitted partial rankings. For hydrocarbon potential, the Straits of Florida planning area was ranked by 9 companies; Eastern, Central, and Western Gulf of Mexico, Northern, Central, and Southern California, and Chukchi Sea each were ranked by 12 companies; all other planning areas each were ranked by 11 companies. Table D-1 shows the overall ranking and the range of companies' rankings with respect to interest in OCS planning areas.

The relatively few responses received from the March 22, 1985, Federal Register Notice of request limits the scope and sophistication of the analysis. The aggregate rankings provide only an approximation and general guide to industry interest in particular planning areas. Since some respondents provided only partial rankings of planning areas, any method used to compile an overall composite ranking of industry interest and hydrocarbon potential results in some distortion of information. However the relatively larger sample size and completeness of information provided in response to the February 7, 1986, request, should result in a somewhat more accurate set of composite rankings than appeared in the Proposed Program. While the data base for this analysis may appear to be better or more complete, it should be remembered that not all companies operate with the same information base, investment strategy, and experience. Thus, the rankings among companies may not reflect comparable method of assessment. Table D-2 shows the rank order of planning areas based on MMS's risked estimates of unleased undiscovered economically leasable resources and industry rankings of planning areas by interest and potential using three different averaging techniques.

Each set of industry rankings in Table D-2 is based on a different method for calculating the mean of the submitted rankings. It is possible to use several measures of central tendency to compare the relative rankings of planning areas as submitted by respondents. The small sample of data in this case suggests that using the mean of the individual rankings to compile a composite ranking may provide the most meaningful analysis of the results. The overall ranking in Table D-1 is a composite based on the mean of the individual planning area rankings.

Table D-1

Industry Interest in OCS Planning Areas Based on the February 1986 Request
(Not all companies ranked all areas)

| Overall Rank /1 | Range of Companies' Rankings /2 |
|---|---|
| 1. Central Gulf of Mexico | 1-2 |
| 2. Western Gulf of Mexico | 2-4 |
| 3. Eastern Gulf of Mexico | 3-8 |
| 4. Beaufort Sea | 1-14 |
| 5. Southern California | 1-12 |
| 6. Central California | 2-15 |
| 7. North Aleutian Basin | 5-9 |
| 8. Northern California | 2-13 |
| 9. Chukchi Sea | 4-16 |
| 10. Navarin Basin | 7-15 |
| 11. North Atlantic | 6-17 |
| 12. St. George Basin | 6-18 |
| 13. Mid-Atlantic | 7-22 |
| 14. Hope Basin | 8-21 |
| 15. Washington-Oregon | 7-22 |
| 16. Cook Inlet | 8-22 |
| 17. South Atlantic | 8-22 |
| 18. Norton Basin | 9-20 |
| 19. Gulf of Alaska | 12-22 |
| 20. Straits of Florida | 14-26 |
| 21. Shumagin | 14-25 |
| 22. St. Matthew-Hall /3 | 16-26 |
| 23. Kodiak | 17-25 |
| 24. Aleutian Basin /3 | 14-25 |
| 25. Bowers Basin /3 | 21-26 |
| 26. Aleutian Arc /3 | 21-26 |

/1 Rank order of mean (average) ranks of companies ranking the OCS planning area on the basis of interest in exploration and development.

/2 Reflects highest and lowest ranking by companies ranking the particular OCS planning area on the basis of interest in exploration and development.

/3 These four areas were deferred at the Draft Proposed 5-Year Program stage.



Table D-2--MMS/Industry Rankings of Planning Areas for the Proposed Final 5-Year Program /1

| Planning Area /2 | Rank Order by MMS Risked Estimates of Unleased Undiscovered Economically Leasable Resources in Millions of BOE (As of Mid-1987) /3 Low - High | Rank Order for All Companies Ranking Planning Area Interest/Potential (As of Jan. 1987) | Adjusted Rankings of Interest/Potential: Highest Unassigned Value Used for Unranked Planning Areas (As of Jan. 1987) /4 | Adjusted Rankings of Interest/Potential: Middle Value Among Unassigned Values Used for Unranked Planning Areas (As of Jan. 1987) /5 |
|---|---|---|---|---|
| Western Gulf of Mexico | 1 (3,790 - 4,630) | 2/3 | 2/3 | 2/2 |
| Central Gulf of Mexico | 2 (3,930 - 4,110) | 1/1 | 1/1 | 1/1 |
| Southern California | 3 (380 - 820) | 5/4 | 5/4 | 4/4 |
| Navarin Basin | 4 (* - 790) | 10/10 | 10/10 | 10/10 |
| South Atlantic | 5 (250 - 770) | 17/17 | 17/17 | 17/17 |
| Eastern Gulf of Mexico | 6 (180 - 470) | 3/5 | 3/5 | 3/5 |
| Northern California | 7 (180 - 410) | 8/9 | 8/9 | 7/9 |
| St. George Basin | 8 (* - 260) | 12/11 | 12/11 | 12/11 |
| Beaufort Sea /6 | 9 (* - 310) | 4/2 | 4/2 | 5/3 |
| Central California | 10 (120 - 230) | 6/7 | 6/7 | 6/7 |
| Mid-Atlantic | 11 (90 - 230) | 13/18 | 13/18 | 13/18 |
| Washington-Oregon | 12 (50 - 60) | 15/14 | 15/14 | 15/14 |
| North Atlantic | 13 (10 - 70) | 11/12 | 11/12 | 11/12 |
| Straits of Florida | 14 (* - 10) | 20/20 | 21/22 | 21/22 |
| Chukchi Sea /6 | 15 (* - 400) | 9/6 | 9/6 | 9/6 |
| Gulf of Alaska | 16 (* - 30) | 19/19 | 19/19 | 19/19 |
| North Aleutian Basin | 17 (* - 20) | 7/8 | 7/8 | 8/8 |
| Norton Basin | 18 (* - 20) | 18/16 | 18/16 | 18/16 |

Table D-2 (continued) MMS/Industry Rankings of Planning Areas for the Proposed Final 5-Year Program /1

| Planning Area /2 | Rank Order by MMS Risked Estimates of Unleased Undiscovered Economically Leasable Resources in Millions of BOE (As of Mid-1987) /3 | Rank Order for All Companies Ranking Planning Area Interest/Potential (As of Jan. 1987) | Adjusted Rankings of Interest/Potential: Highest Unassigned Value Used for Unranked Planning Areas (As of Jan. 1987) /4 | Adjusted Rankings of Interest/Potential: Middle Value Among Unassigned Values Used for Unranked Planning Areas (As of Jan. 1987) /5 |
|---|---|---|---|---|
| Kodiak | * | 23/23 | 23/23 | 23/23 |
| Hope Basin | * | 14/13 | 14/13 | 14/13 |
| Shumagin | * | 21/22 | 20/21 | 20/21 |
| Cook Inlet | * | 16/15 | 16/15 | 16/15 |
| Aleutian Basin /7 | * | 24/24 | 24/24 | 24/24 |
| Bowers Basin /7 | * | 25/25 | 25/25 | 25/25 |
| St. Matthew-Hall /7 | * | 22/21 | 22/20 | 22/20 |
| Aleutian Arc /7 | * | 26/26 | 26/26 | 26/26 |

/1 Industry rankings were made in Spring 1986 by companies estimating interest and potential effective January 1987.
/2 Planning areas are ordered by "Leasable Resources" assuming a $24 per barrel starting oil price (see Appendix F).
/3 The range of "Leasable Resources" is based on assumptions of a low oil price case and a high oil price case (1984 starting prices). The stub of the table is rank ordered by leasable resources based on the assumption of $24 per barrel (1984 starting price) (see Appendix F).
/4 Any planning area not ranked by a company was adjusted by assigning the area the highest value not assigned by the company submitting the rankings.
/5 Any planning area not ranked by a company was adjusted by assigning the area the middle value among the unassigned values submitted by the company.
/6 Calculations exclude Beaufort Sea and Chukchi Sea natural gas (see Appendix F).
/7 These four areas were deferred from the Draft Proposed 5-Year Program.

* Neglible (estimated to be less than 0.5 million BOE). The eight lowest ranked planning areas have been assigned no rank order because their resource magnitudes are estimated to be neglible.





A few companies provided only partial rankings. Some difficulty is encountered when trying to make an evenhanded comparison of planning areas when data elements are missing. While the overall ranking shown in Table D-1 offers a good composite interpretation of this information. Table D-2 contains two additional displays of composite rankings which are an effort to address any inconsistency in comparing planning areas that results from partial rankings.

To overcome the difficulty of dealing with unranked areas, surrogate values can be assigned using one or more schemes to indicate implied rankings. The purpose of using surrogate values is to provide a common basis for comparing the rankings. The use of surrogate values allows a comparison of rankings submitted by all respondents without adjusting the number of cases within each rank when calculating the mean value for planning areas where data elements are missing. Two suggested schemes for handling implied rankings are:

-assign each unranked area the highest rank not assigned by a company (i.e. assign a surrogate value of 11 to each unranked planning area if the company ranked only 10 areas, 16 if the company ranked 15 areas, and so on); and

-to assign each unranked area a middle value among the unassigned values submitted by the particular company (i.e. assign a surrogate value of 18 to each unranked planning area for a company listing only 10 areas--18 is the mid-point between 10 and 26).

Each of these two ranking schemes results in some slight distortion. Such distortion notwithstanding, each ranking scheme described above provides an alternative approach to showing the composite rankings of respondents. These methods of adjusting rankings to include implied data are an effort to allow an even comparison of the information supplied by the companies. The use of these alternative approaches is especially important since the number of cases included in the overall analysis is small.

The first display of industry rankings (Column 3) on Table D-2 is based on the calculation of an individual arithmetic mean for each of the 26 planning areas. Calculation of the arithmetic mean for each of the rank orders is based on the number of respondents (n) ranking each planning area. No values were assigned to unranked areas.

The second display of industry rankings (Column 4) on Table D-2 is also based on the calculation of the individual arithmetic mean for each of the 26 planning areas. The mean for each of the interest rankings (the number to the left of the slash) for each of the planning areas was calculated using an n of 13 cases; the mean for each of the potential rankings (the number to the right of the slash) for each of the planning areas was calculated using an n of 12 cases. Unranked planning areas were assigned the highest rank order not assigned by the respondent submitting the rankings.

A third display of industry rankings (Column 5) of Table D-2 was also calculated using the individual arithmetic mean for each of the 26 planning areas except that unranked planning areas were assigned the middle value (rank order) among the unassigned values submitted by each respondent. Within each ranking scheme, the rank order values used to compile both industry interest and potential were handled using the same technique as that used for Column 4. In both Columns 4, and 5 interest was calculated using an n of 13 cases and potential was calculated using an n of 12 cases because one industry respondent submitted rankings for interest only.

A few of the comments received on the Proposed Program focused on the methodology used for compiling industry interest rankings. In response to comments from the Governor of Rhode Island, this analysis now includes a table of industry interest rankings (Table D-3) showing the mode(s) of the rankings of individual planning areas. The mode is the rank assigned most frequently to each planning area by industry respondents. The mode is an indicator of central tendency and showing it provides another way of looking at the typical or representative rank assigned to each planning area by industry respondents. The mode in this case is the rank that sometimes represents a clustering of opinion concerning industry's preferences. Unlike the mean, the mode is generally less affected by extremes of rank. Table D-3 shows the planning areas and modes including the frequency of occurrence with which each planning area was ranked by industry respondents.

In comments on the Proposed Program, the Natural Resources Defense Council (NRDC) suggested that planning areas not ranked by a particular company should be assumed to be areas of no exploration interest and to be areas with a geological potential of zero. Using these assumptions, the overall rank order of planning areas changes little compared to the industry interest rankings as shown in Table D-1 and to the hydrocarbon potential rankings shown to the right of the slash in Table D-2, Column 3. For example, assuming a rank of zero for interest, a recalculation of the rankings would result in North Aleutian Basin moving from 7 to 6, and Straits of Florida moving from 20 to 19 in the rankings for industry interest; Central California would move from 6 to 7 and Gulf of Alaska would move from 19 to 20 in the overall industry interest ranking. The results for hydrocarbon potential, assuming a rank of zero for unranked planning areas, would show the following changes: North Aleutian would rise from 8 to 7 and Straits of Florida would rise from 20 to 16; Central California would drop from 7 to 8, Norton Basin would drop from 16 to 17, South Atlantic would drop from 17 to 18, Mid-Atlantic would drop from 19 to 20. Only the Straits of Florida would move more than one step in the composite rankings using this methodology. This information is available for consideration by the Secretary as part of the 5-Year Program Administrative Record.

The Proposed Program included two tables of composite rankings showing the range of industry interest in OCS planning areas based on comments received in response to the July 1984 and the March 1985 Federal Register Notices. Tables D-4 and D-5, respectively, show these earlier rankings of industry interest.



Table D-3

Industry Interest in OCS Planning Areas Based on the February 1986 Request
(Not all companies ranked all areas)

| Planning Area /1 | Mode(s) of Rankings (Frequency) |
|---|---|
| Central Gulf of Mexico | 1 (11) |
| Western Gulf of Mexico | 2 (9) |
| Eastern Gulf of Mexico | 3 (5) |
| Beaufort Sea | 3 (3) |
| Southern California | 4 (3) |
| Central California | 5 (3) |
| North Aleutian Basin | 9 (4) |
| Northern California | 7 (3),8(3),9(3) |
| Chukchi Sea | 4 (2),5(2),9(2),16(2) |
| Navarin Basin | 10 (5) |
| North Atlantic | 11 (3),15(3) |
| St. George Basin | 12 (3) |
| Mid-Atlantic | 10 (2),14(2),18(2) |
| Hope Basin | 13 (3) |
| Washington-Oregon | 10 (2),14(2),18(2) |
| Cook Inlet | 10 (2),20(2) |
| South Atlantic | 11 (3),19(3) |
| Norton Basin | 16 (2),18(2),19(2),20(2) |
| Gulf of Alaska | 19 (3) |
| Straits of Florida | 20 (2) |
| Shumagin | 22 (3) |
| St. Matthew-Hall | 21 (4) |
| Kodiak | 23 (5) |
| Aleutian Basin | 24 (5) |
| Bowers Basin | 24 (4),26(4) |
| Aleutian Arc | 25 (5) |

/1 Planning areas are ordered by mean (average) ranks of companies ranking the OCS planning area on the basis of interest in exploration and development. See Table D-1 for overall rank.

Table D-4
Industry Interest in OCS Planning Areas Based on the July 1984 Request /1
(Not all companies ranked all areas)

| Overall Ranking /2 | Range of Companies' Rankings /3 |
|---|---|
| 1 Central Gulf of Mexico | 1 to 5 |
| 2 Western Gulf of Mexico | 1 to 7 |
| 3 Beaufort Sea | 1 to 7 |
| 4 (tie) Southern California | 1 to 11 |
| 4 (tie) Central & Northern California | 3 to 14 |
| 6 Eastern Gulf of Mexico | 3 to 12 |
| 7 Navarin Basin | 2 to 11 |
| 8 North Aleutian Basin | 3 to 14 |
| 9 St. George Basin | 3 to 15 |
| 10 Chukchi Sea | 2 to 13 |
| 11 North Atlantic | 7 to 22 |
| 12 Norton Basin | 8 to 18 |
| 13 Washington-Oregon | 5 to 21 |
| 14 Mid-Atlantic | 9 to 23 |
| 15 Hope Basin | 10 to 19 |
| 16 Cook Inlet | 9 to 20 |
| 17 Shumagin | 12 to 22 |
| 18 South Atlantic | 10 to 24 |
| 19 Gulf of Alaska | 12 to 21 |
| 20 St. Matthew-Hall | 14 to 23 |
| 21 Kodiak | 13 to 24 |
| 22 Bowers Basin | 16 to 24 |
| 23 (tie) Aleutian Arc | 12 to 24 |
| 23 (tie) Aleutian Basin | 15 to 23 |

/1 This table is included for historic purposes. See cautionary note in the paragraph on p. D-11.

/2 Rank order of mean (average) ranks of companies ranking the OCS planning area on the basis of interest in exploration and development.

/3 Reflects highest and lowest ranking by companies ranking the particular OCS planning area on the basis of interest in exploration and development.



Table D-5
Industry Interest in OCS Planning Areas Based on the March 1985 Request /1
(Not all companies ranked all areas)

| Overall Ranking /2 | Range of Companies' Rankings /3 |
|---|---|
| 1 Central Gulf of Mexico | 1 to 2 |
| 2 Western Gulf of Mexico | 2 to 5 |
| 3 Beaufort Sea | 1 to 6 |
| 4 Southern California | 1 to 8 |
| 5 Eastern Gulf of Mexico | 3 to 10 |
| 6 North Aleutian Basin | 3 to 9 |
| 7 Central California | 4 to 11 |
| 8 Navarin Basin | 4 to 10 |
| 9 Northern California | 4 to 11 |
| 10 Chukchi Sea | 4 to 20 |
| 11 St. George Basin | 8 to 17 |
| 12 Norton Basin | 9 to 18 |
| 13 Hope Basin | 9 to 19 |
| 14 North Atlantic | 12 to 17 |
| 15 Mid-Atlantic | 11 to 21 |
| 16 Cook Inlet | 10 to 21 |
| 17 South Atlantic | 12 to 22 |
| 18 Washington-Oregon | 11 to 22 |
| 19 Straits of Florida | 14 to 24 |
| 20 Gulf of Alaska | 15 to 22 |
| 21 Shumagin | 14 to 25 |
| 22 Kodiak | 18 to 25 |
| 23 St. Matthew-Hall /4 | 16 to 26 |
| 24 Aleutian Basin /4 | 14 to 25 |
| 25 Bowers Basin /4 | 21 to 26 |
| 26 Aleutian Arc /4 | 20 to 26 |

/1 This table is included for historic purposes. See cautionary note in the paragraph on p. D-11.

/2 Rank order of mean (average) ranks of companies ranking the OCS planning area on the basis of interest in exploration and development.

/3 Reflects highest and lowest ranking by companies ranking the particular OCS planning area on the basis of interest in exploration and development.

/4 These four areas were deleted from the Draft Proposed 5-Year Program.

Rankings based on the response to the February 1986 Federal Register Notice (Table D-1) may provide a more reliable indication of industry interest for the Proposed Final Program and attention should focus on them rather than on the earlier rankings. Several reasons for this are apparent. The current rankings reflect the second opportunity that industry respondents have had to evaluate and rank 26 planning areas. The rankings based on the February 1986 Federal Register Notice of request are from a larger sample of responses than the rankings based on the March 1985 request and on a more complete set of data than were submitted for either of the earlier rankings. The current rankings contain relatively fewer submittals of partial rankings. Furthermore, the rankings submitted following the February 1986 request, are likely to have been based on companies' recent evaluations of interest and potential in light of changing oil prices, market conditions, and offshore exploration and development economics. To combine or closely compare the three sets of rankings is not recommended since a comparison of these data may be misleading.

# APPENDIX E

# GEOLOGICAL AND GEOPHYSICAL DATA

## GEOLOGICAL AND GEOPHYSICAL DATA

CONTENTS





## I. Geological & Geophysical Data

A brief synopsis of the seismic, continental offshore stratigraphic test (COST) well and exploratory well data available in each planning area is presented below. The figures given for seismic data indicate the amount of such data acquired by the Minerals Management Service (MMS) as of the end of Fiscal Year 1985.

### The Navarin Basin Planning Area

Seismic surveying activity by government and academic institutions has been ongoing since the mid-1960's. These surveys have been mostly reconnaissance mapping efforts investigating the regional geologic framework. Industry-related seismic activity has been ongoing since 1971. A total of 49,000 line miles of common-depth-point (CDP) seismic reflection data have been acquired by the MMS. ARCO Alaska, Inc., drilled a COST well in the summer of 1983, and 8 exploratory wells have been drilled as of July 1, 1986.

### Hope Basin Planning Area

Two State stratigraphic test wells, the Nimiuk Point No. 1 and the Cape Espenberg No. 1 wells, were drilled north and south of the entrance to Kotzebue Sound just east of the planning area in 1974 and 1975 by Standard Oil of California. Seismic exploration in the area began in 1972. The MMS has acquired 8000 line-miles of CDP seismic surveys collected by industry and supplemented by U.S. Geological Survey (USGS) regional seismic data.

### Beaufort Sea Planning Area

Industry began acquiring CDP seismic data in Federal waters in 1964, and 40,000 by the MMS. Thirteen exploratory wells have been completed on Federal acreage as of July 1, 1986.

### Kodiak Planning Area

A total of 19,000 line-miles of seismic data shot across Kodiak shelf have been acquired. Several stratigraphic test wells have been drilled on Kodiak shelf. The first three, which were drilled in 1976, KSST 1, 2, and 3, reached total depths of 4,225 feet, 4,337 feet, and 1391 feet respectively. The remaining three wells, KSSD 1,2, and 3, were drilled the following year and reached total depths of 8,514 feet, 10,452 feet, and 9,355 feet, respectively. In addition, in 1971, the Deep Sea Drilling Project (DSDP) drilled two holes on the continental slope off Kodiak Island.

Norton Basin Planning Area

Seismic reflection surveying by government and academic institutions has been ongoing since the mid-1960's. These surveys have been mostly reconnaissance mapping efforts investigating the regional geologic framework. Industry has been surveying Norton Sound since 1971 in order to establish a high density seismic grid covering the prospective areas of the basin. A total of 26,000 line-miles of CDP seismic data have been acquired by the MMS. ARCO Alaska, Inc., drilled two COST wells in the planning area during the summers of 1980 and 1982. Six exploratory wells have been drilled as of July 1, 1986.

Chukchi Sea Planning Area

The first exploration permit for the Chukchi Sea planning area was issued in 1969. The MMS has acquired approximately 37,000 line-miles of CDP seismic data. No COST wells have been drilled.

St. George Basin Planning Area

Seismic exploration in St. George Basin has been occurring since 1970, and more than 49,000 line-miles of seismic data have been acquired. The basin is in the early stage of exploratory drilling. Two COST wells and ten exploratory wells have been completed as of July 1, 1986.

Shumagin Planning Area

The Shumagin planning area is a frontier region without well data. A geophysical grid pattern of 24-and 48-fold CDP data shot from 1974 to the present within the Shumagin planning area, along with geologic and geophysical data on the adjacent Kodiak shelf, is the basis for understanding the resource potential for the Shumagin planning area. The MMS has acquired 8,000 line-miles of CDP seismic data.

Gulf of Alaska Planning Area

Permits for seismic acquisition in the Gulf of Alaska were first issued in 1962. A total of 34,000 line-miles of CDP seismic data have been acquired. Twelve exploratory wells and one COST well have been drilled since 1977 without discovery of an oil or gas reservoir as of July 1, 1986.

Cook Inlet Planning Area

Permits to collect seismic data in the Cook Inlet area were first issued in 1964. The MMS has acquired 15,000 line-miles of CDP seismic data. One COST well and thirteen exploratory wells have been drilled as of July 1, 1986.



North Aleutian Basin Planning Area

Collection of geophysical data in the North Aleutian Basin began in 1963. The MMS has acquired 42,000 line-miles of CDP seismic data. One COST well was completed in January 1983. Ten exploratory wells have been drilled on the Alaska Peninsula adjacent to the axis of Bristol Bay as of July 1, 1986.

North Atlantic Planning Area

The MMS has acquired approximately 68,000 line-miles of CDP seismic data in the North Atlantic planning area. Two COST wells, completed in 1976 and 1977, and eight exploratory wells have been drilled as of July 1, 1986.

Mid-Atlantic Planning Area

The MMS has acquired approximately 55,000 line-miles of CDP seismic data in the Mid-Atlantic planning area. Two COST wells, completed in 1976 and 1979, and 32 exploratory wells have been drilled as of July 1, 1986.

South Atlantic Planning Area

The MMS has acquired approximately 55,000 line-miles of CDP seismic data in the South Atlantic planning area. One COST well, completed in 1977, and six exploratory wells have been drilled as of July 1, 1986.

Straits of Florida Planning Area

The MMS has acquired about 2,000 line-miles of CDP seismic data in the Straits of Florida planning area. Fourteen exploratory wells have been drilled in the Florida Keys area, including 3 in the Straits of Florida planning area, as of July 1, 1986.

Eastern Gulf of Mexico Planning Area

Approximately 86,000 line miles of seismic data have been acquired by the MMS in this planning area. A total of 33 exploratory wells* have been drilled as of July 1, 1986.

Central Gulf of Mexico Planning Area

Approximately 141,000 line miles of seismic data have been acquired by the MMS in this planning area. A total of 5,804 exploratory wells and 14,836 development wells have been drilled as of July 1, 1986.

Western Gulf of Mexico Planning Area

Approximately 120,000 line miles of seismic data have been acquired by the MMS in this planning area. Two COST wells, 1,522 exploratory wells, and 1,586 development wells have been drilled as of July 1, 1986.

* One of these wells was mistakenly identified as a development well in the Proposed Program (February 1986).

Southern California Planning Area

The MMS has acquired approximately 62,000 line-miles of seismic data in this planning area. Two COST wells have been completed: one in 1975 and another in 1978. A total of 298 exploratory wells and 592 development wells have been drilled as of July 1, 1986.

Central California Planning Area

The MMS has acquired approximately 19,000 line-miles of seismic data in this planning area. Twelve exploratory wells were drilled from 1964 to 1967.

Northern California

The MMS has acquired approximately 11,000 line-miles of seismic data in this planning area. Seven exploratory wells were drilled from 1964 to 1966.

Washington-Oregon Planning Area

The MMS has acquired approximately 7,000 line-miles of seismic data in this planning area. Twelve exploratory wells were drilled from 1965 to 1967.



II. Grid Coverage/Quality of Geological and Geophysical Data for Regional Resource Estimates /1

| Area | Coverage/Quality |
|---|---|
| **Atlantic** | |
| North | Good |
| Mid | Good |
| South | Poor to Fair |
| Straits of Florida | Very Poor |
| **Alaska** | |
| Beaufort Sea | Fair to Good |
| Chukchi Sea | Poor |
| Hope Basin | Fair |
| Norton Basin | Fair to Good |
| Navarin Basin | Fair to Good |
| St. George Basin | Good |
| North Aleutian Basin | Good |
| Kodiak | Good |
| Cook Inlet | Good |
| Gulf of Alaska | Fair to Good |
| Shumagin | Very Poor |
| **Gulf of Mexico** | |
| Central | Excellent |
| Western | Excellent |
| Eastern | Good |
| **Pacific** | |
| Northern California | Poor to Good |
| Central California | Poor to Good |
| Southern California | Fair to Excellent |
| Washington-Oregon | Poor |

/1 Supplied by MMS regional offices based upon quantity and quality of data currently available.

## III. Value of Additional Data

The value of additional geological and reservoir engineering data in a particular area is dependent upon: a) the geology of the area, b) the existing data base, and c) the extent to which the new information and data conform to the previous interpretations.

In the simplest case, a frontier OCS area (including some deepwater portions of the GOM) with little or no existing empirical geological and reservoir engineering data, extrapolation of geologic data from onshore and bottom samples, and comparison to analog basins/areas is necessary. Exploration of these areas generally involves high geologic and economic risk. Early exploration focuses on large easily identifiable structural targets. More than 75 percent of the world's giant (500 MMBO or larger) oil fields are found in structural traps. In this type of area the value of new information is tremendous. If it tends to confirm a particular interpretation, it is valuable because it reduces uncertainties (it may in fact invalidate previous interpretations, also reducing uncertainty). If the new information does not confirm previous interpretations, it is valuable because it results in new interpretations that may lead to additional exploration and with that, additional information.

In an intermediate case, a moderately explored area with existing production, additional information is generally less valuable. In this case both the larger and the less risky structures have been explored. Exploration shifts to smaller, more subtle prospects. In this type of area, empirical geological and reservoir engineering data are available. It is much more difficult for the information obtained from an additional well to influence interpretations and exploration strategies covering large areas or entire basins.

On the other end of the spectrum are mature producing areas such as the shallow water GOM shelf. Extensive geological and reservoir engineering data exist. Only the smallest and subtlest traps remain to be explored. In these areas it is extremely unlikely (almost impossible) for the information obtained from an additional well to have any regional influences because of the abundance of existing information. The value of this information is generally to reduce uncertainties surrounding that particular prospect--existence of trapping mechanisms and hydrocarbons; the amount of pay and potential reservoir rock, etc. However, information gained from drilling a well to deeper prospects to reevaluate old acreage, a current industry trend, could be extremely important in indicating regional sand distribution and geology.

APPENDIX F

# ECONOMIC CONSIDERATIONS IN THE 5-YEAR OUTER CONTINENTAL SHELF OIL AND GAS LEASING PROGRAM

ECONOMIC CONSIDERATIONS IN THE 5-YEAR
OUTER CONTINENTAL SHELF LEASING PROGRAM

CONTENTS



ILLUSTRATIONS



TABLES

# ECONOMIC CONSIDERATIONS IN THE 5-YEAR OUTER CONTINENTAL SHELF OIL AND GAS LEASING PROGRAM

## I. Introduction

This appendix discusses the economic considerations that are important in the formulation of a 5-year OCS oil and gas leasing program. It also describes the methods used to estimate the economic benefits of leasing and gives the resulting estimates for the various planning areas of the OCS.

Past practice and court rulings have established the qualitative and quantitative analysis of the benefits of OCS oil and gas production as an essential part of the considerations required of the Secretary of the Interior in formulating a 5-year leasing program under section 18 of the OCS Lands Act (OCSLA). Thus, in section II the statutory objectives of the OCSLA and the considerations required in formulating a leasing program are discussed and translated into economic terms.

Section III gives a brief history of OCS leasing.

Section IV discusses the relevance and importance of economic considerations in the management of OCS oil and gas resources and explains how the U.S. economy benefits from the production of OCS oil and gas.

In section V, the discussion turns to the economic characteristics of OCS oil and gas resources and the basic economic investment decisions involved in bringing them into production. This discussion yields a general rule for sequencing the development of these resources that would maximize their economic benefits to society which is important to consider in formulating a 5-year leasing program.

Section VI examines the sequencing of oil and gas investment decisions in the private sector. It also presents the resource and economic estimates used in developing the 5-year program.

Section VII describes the computational methods and assumptions used to estimate the geologic and economic measures associated with leasing and investing in each OCS planning area. These estimates provide the basic direct economic criteria which are considered by the Secretary, along with other important factors, in structuring, evaluating, and choosing among alternative leasing schedules for the 5-year program.

## II. Statutory Objectives and Economic Benefits

The OCS Lands Act Amendments of 1978 establish specific purposes relating to the development of the oil and natural gas resources of the OCS. Among these purposes are those which can be categorized as economic considerations which are to be taken into account in managing the oil and gas resources.

Section 102(1) requires policies and procedures to be established:

> . . . which are intended to result in expedited exploration and development of the Outer Continental Shelf . . .
>
> in order to achieve national economic and energy policy goals,
>
> assure national security,
>
> reduce dependence on foreign sources, and
>
> maintain a favorable balance of payments in world trade;

Section 102(2) goes on to require the development of the oil and gas resources of the OCS in a manner consistent with the responsibility:

> . . . to make such resources available to meet the Nation's energy needs as rapidly as possible . . .
>
> to balance orderly energy resource development with protection of the human, marine, and coastal environments,
>
> to insure the public a fair and equitable return on the resources . . . and
>
> to preserve and maintain free enterprise competition . . . .

Section 18(a) requires the Secretary to prepare, revise, and maintain a 5-year leasing program consisting of a schedule of lease sales which considers, among other things, economic values of the nonrenewable resources of the OCS.

Development of oil and gas resources should be viewed within the context of the Federal Government's overall national energy policy as expressed in the The National Energy Plan, U.S. Department of Energy, 1985. The central goal of the national energy policy is to foster an adequate supply of energy at reasonable costs. The basic strategies for achieving that goal are to promote a balanced and mixed energy resource system, and to maximize the practical reliance on the free decisions of the entire populace, while maintaining public health and safety, and environmental quality. The 1985 National Energy Policy Plan reflects the understanding of the strategic importance of spending almost $50 billion in 1985 on net energy imports. It also recognizes that the U.S. remains part of a world energy system in which our own prices and supplies are affected by events around the globe.



This latter condition has been most evident in the first half of 1986 as the price of oil declined by half. Until there are breakthroughs in the capital-intensive costs of some widely available renewable resources (for example, solar energy) and the high gathering or processing costs of other sources (for example biomass, shale, oil, and synthetics), Americans must focus their consumption on what is readily available. For many years to come, the U.S. will need more oil and gas from its domestic sources including the OCS.

The National Energy Policy Plan states that, in addition to promoting a free-market economy and full deregulation of natural gas, the most vital component of Federal action is the timely development of oil and gas resources on the OCS. The Administration opposes any moratorium on OCS leasing. Preventing development of domestic resources on the OCS only strengthens OPEC's efforts to restrict production and raise prices; the Nation's dependence on imported oil increases, its energy security is lessened, and the pace of economic growth is slowed. Within the context of the overall economic goal of maximum reliance on the private sector to make decisions about production, the private marketplace is given great weight in determining timeliness and efficiency of OCS oil and gas exploration and development. The Federal Government, on the other hand, plays a major role because of its ownership of the OCS oil and gas resources. The Federal Government aims at the initial structuring of that marketplace in a manner which does not restrict the orderly and timely development of the resource, while assuring the public a fair return for the rights conveyed. Because oil and gas affects the entire U.S. economy, its development is intricately tied to overall sustained economic growth. The domestic production of oil and gas not only results in the production of these hydrocarbons and their associated market values, along with the jobs and income created and the contribution of these products to the sustained growth of the industrial, transportation, and residential/commercial sectors; it also has secondary and tertiary linkages to income generation and jobs in other sectors of the economy.

As will be discussed in section IV, the primary benefit of efficient OCS oil and gas development is the availability of oil and gas at a cost to the economy that is less than the market price. To the extent that more OCS oil and gas is produced and costs are less than the market price, the U.S. economy will be more productive overall, yielding a greater total of goods and services valued by American consumers.

The economic benefits of timely and efficient exploration and development of the oil and gas resources of the OCS can be measured quantitatively to determine the potential contribution which these resources might make to the productivity of the U.S. economy. They can be measured in terms of the present value of expected receipts to the U.S. Government in the form of bonuses, rentals, royalties, and taxes, plus the economic profits accruing to industry. They also can be measured equivalently as the present value of the expected production revenues less the costs of OCS activities. These estimates are subject to great uncertainties and are very sensitive to changes in the likely presence of oil. For this reason, and because of the great fluctuations of oil prices over the past 6 months, a range of possible estimates is presented in this document. The net present value of undiscovered economically recoverable OCS petroleum resources in "leasable" prospects remaining to be offered at the start of the next 5-year program is estimated to be approximately $20 to $85 billion expressed in May-June 1987 prices.

## III. Brief History of OCS Leasing

Oil production off our shores began in 1896. Approximately 400 shallow wells were drilled from wooden piers extending from the Summerland shoreline, near Santa Barbara, California, in State waters. This was the first time offshore oil was produced in the United States. The first attempt to drill an offshore well in the Gulf of Mexico began in 1933. In October 1937, the first well to produce hydrocarbons from the Gulf of Mexico was drilled off Louisiana; production began in 1938.

From the enactment of the OCSLA in 1953, the Bureau of Land Management (BLM) and subsequently, since 1982, the Minerals Management Service (MMS) have conducted 81 oil and gas lease sales and offerings through April 1986. The first general oil and gas Federal lease sale was held for Gulf of Mexico acreage on October 13, 1954. From that time through 1973, 28 additional OCS sales were held, including 9 drainage sales in the Gulf of Mexico and 15 general lease sales (4 of which were in the Pacific). Generally, one or two sales were held annually until 1969. In January 1969, a blowout occurred on a lease in the Santa Barbara Channel. As a result, no lease sales were held in the Gulf of Mexico until 1970 and in the Pacific until 1975.

In response to the OPEC Oil Embargo of 1973-74, goals were set to lease 10 million acres annually between 1974 and 1980 (an amount equal to the acreage leased in the previous 21 years). As a result, the number of lease sales was increased to 12 in the 3-year period from January 1974 through December 1976 (9 in the Gulf of Mexico and 1 each in the Pacific, Alaska, and the Atlantic). In 1977, two sales were held. Beginning with 1978, the number of sales again increased to four in 1978 and six in 1979. Three sales were held in 1980.

In 1978, the OCSLA was amended. Section 18 of the amended act required the Secretary of the Interior to formulate a 5-year plan for OCS leasing, specifying to the maximum extent practicable the size, timing, and location of lease sales. Section 8 required the Secretary to experiment with offering tracts for lease under different bidding systems for a 5-year period which ended in September 1983. In June 1980, Secretary Andrus adopted the first 5-year leasing program for the period 1980-1985. Under this plan, seven sales were held in 1981 and five in 1982. Various state and environmental groups sued Secretary Andrus. In 1981, the U.S. Court of Appeals for the District of Columbia Circuit held that several aspects of the plan did not conform to the requirements of section 18 and directed the Secretary to correct those deficiencies. After additional studies, Secretary Watt approved the second 5-year leasing program in July 1982 which provided for 41 sales over 5 years and extended the plan through mid-1987. This program was designed primarily to increase the quality, pace, and acreage of offerings to achieve early leasing of high potential areas. The first areawide sale was held in the Mid-Atlantic in April 1983, and the following month the first areawide sale was held in the Central Gulf of Mexico. The results of this latter offering set a new record high for the 30-year leasing program based upon the number of tracts bid on and accepted, the amount of bonus bids exposed, and high bids submitted and accepted.



In the 29 1/2-year history of Federal offshore leasing before areawide offerings (1954 through April 25, 1983):

- 64 million acres of the OCS were offered for lease;
- 27.3 million acres received bids;
- 24 million acres were leased:
  - 16 million acres or 3,559 tracts were leased in 47 sales in the Gulf of Mexico,
  - 2.8 million acres or 512 tracts were leased in 10 sales offshore Alaska,
  - 2.1 million acres or 362 tracts were leased in 8 sales in the Atlantic,
  - 2.4 million acres or 439 tracts were leased in 9 sales in the Pacific. Of the Pacific acreage, 1.5 million acres were in southern California, including the Santa Barbara Channel.

In contrast, since the beginning of areawide leasing on April 26, 1983, through April 29, 1986:

- 356 million acres of the OCS were offered for lease through April 29, 1986.
- 18.0 million acres received bids
- 16.3 million acres were leased:
  - 13.7 million acres or 2,683 tracts were sold in 8 sales in the Gulf of Mexico,
  - 2.2 million acres or 407 tracts were sold in 2 sales offshore Alaska,
  - 0.3 million acres or 48 tracts were sold in 2 sales in the Atlantic,
  - 0.2 million acres or 31 tracts were sold in 2 sales in the Pacific.

A total of 5,195 leases were in effect as of January 1, 1986; this included 4,202 leases in the Gulf of Mexico, 127 in the Atlantic, 172 offshore California, and 694 offshore Alaska.

As of January 1, 1986, 1,503 leases were designated as producing.* Of the total producing leases, 1,465 were in the Gulf of Mexico and 38 were offshore California. The remaining 3,692 leases were nonproducing. OCS revenues (bonuses, rentals, and royalties) received totaled more than $81 billion for the period from 1954 through 1985.

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* Includes both producing and producible leases.

The scope and emphasis of the July 1982 5-year plan was a significant change from the past programs that generated leasing of about 3 percent of the OCS in 29-1/2 years. It is predicted that 85 percent of America's untapped oil wealth is on publicly owned lands, two-thirds of which are offshore. The current plan provides access to the most promising offshore areas, allows companies to determine the focus of their exploration efforts, and encourages the flexibility needed to test diverse exploration strategies which could result in major new finds benefiting the nation as a whole.



## IV. The Relevance and Importance of Economic Considerations

### A. Introduction

OCS oil and gas resources represent both a current and potential future domestic energy source to our nation. This section presents a broad overview of the role of energy and, more specifically, oil and gas in our national economy. It presents a general framework of our current and projected domestic production and reserve status of domestic hydrocarbons. In addition, it summarizes our import situation from the 1970's to the present which reflects a combination of Government policies and market influences which have substantially decreased our vulnerability to supply disruptions such as we have experienced in the past. It also addresses what the import picture is likely to be in the future and the implications which this has for our national security and our national economy. This section also discusses the role which OCS oil and gas resources can play in future domestic energy production and the factors which influence their development. Finally, it discusses the ways in which OCS oil and gas resources contribute to the productivity of the U.S. economy and the effect of offshore exploration and development costs on the resulting economic benefits.

### B. Role of Oil and Gas in Our National Economy

#### 1. Energy in General

The role of energy in the maintenance and growth of our industrial economy has been a critical one from its infancy. In 1985, the United States consumed 73.8 quadrillion (quad) British thermal units (Btu) of energy (U.S. Department of Energy, Annual Energy Review, May 1986). Of that total, oil and gas constituted 65.9 percent of our domestic consumption of energy, coal represented 23.7 percent, and the remaining 10.4 percent was hydroelectric, nuclear, geothermal, wood, waste, and wind energy. Table 1 presents a breakdown of 1985 U.S. energy consumption by source.

Energy consumption in 1985 by the three major end-use sectors was: the residential and commercial sector consumed 36.6 percent of the total; the industrial sector consumed 35.1 percent of the total; and the transportation sector consumed 27.1 percent of the total. (Ibid).

The international events of the 1970's, highlighted by the OPEC oil embargo of 1973, resulted in significant changes in the use of energy within the U.S. economy. The dramatic increase in the price of oil on the world market (from October 1973 to January 1974, the price quadrupled) resulted in energy use efficiency and conservation measures in the United States that were unparalleled in our history. Energy efficient home-heating devices and the switch to more fuel-efficient cars began during this period, reflecting the American consumers' reaction to increased prices.

TABLE 1

U.S. 1985 CONSUMPTION OF ENERGY BY SOURCE 1/

| | Quadrillion Btu 2/ |
|---|---|
| Petroleum | 30.85 |
| Natural Gas (dry) | 17.76 |
| Coal | 17.50 |
| Hydroelectric Power | 3.38 |
| Nuclear Electric Power | 4.14 |
| Other 3/ | 0.20 |
| TOTAL ENERGY CONSUMED 4/ | 73.83 |

1/ Preliminary

2/ 1 Quadrillion Btu/year = 0.4724 MMBD (million barrels per day) of domestic oil
= 0.4696 MMBD of imported oil
= 2.649 billion cubic feet of natural gas/day

3/ Includes electricity produced from geothermal wood, waste, wind, photovoltaic, and solar thermal sources connected to electric utility distribution systems and net imports of coal coke.

4/ Total does not equal sum of components due to independent rounding.

Source: U.S. Department of Energy, Energy Information Administration (DOE/EIA), Annual Energy Review 1985, May 7, 1986, p.5.



One measure which reflects the more efficient use of energy in the economy is the amount of energy consumed per dollar of Gross National Product (GNP). In the period from 1950 to 1973 energy comsumption increased about 3.5 percent annually or about the same as the growth in real GNP. (U.S. Department of Energy, National Energy Policy Plan Projections to 2010, December 1985, p. ES-5.) In response to the energy price increase of the 1970's, energy consumed per dollar of real GNP declined annually from a 1970 high of 27.49 thousand Btu per dollar (1982) of GNP to 20.68 thousand Btu per dollar of GNP (1982 dollars) in 1985. (U.S. Department of Energy, Annual Energy Review, May 1986, p.4).

The U.S. Department of Energy projects that this energy efficiency trend will continue; between 1984 and 2000, the quantity of energy consumed is projected to increase at 1.6 percent per year, significantly less than the 2.9 percent annual rate of projected growth in U.S. GNP (DOE National Energy Policy Plan Projections to 2010, December 1985, Ibid). This would amount to an increase in energy consumption during the period 1984 to 2010 of about 30 percent. (Ibid). 1/

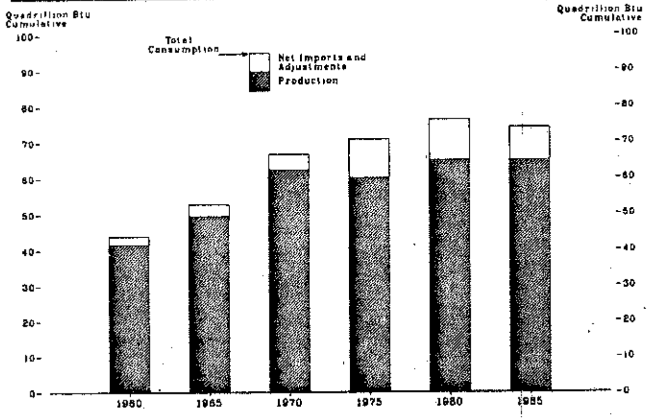
2. Oil and Gas

Relative to the United States supply of energy from other sources, a substantial percentage of our oil supply and, to a lesser extent, gas supply is imported. Figures 1 and 2 graphically illustrate the role of imports, and more specifically petroleum, in our total supply of energy and its disposition (primarily consumption and exports). In the 1970 to 1980 timeframe, domestic oil and gas production represented approximately 52 to 60 percent of the total energy supplied to the U.S. economy; imports of oil and gas supplied approximately 11 to 19.0 percent (see Table 2). U.S. Department of Energy projections to the year 2010 indicate that imported oil and gas will supply an estimated 18.6 percent of our total domestic energy in the year 2010. (Imported gas constitutes approximately 3 percent of the 18.6 percent.) These long term import projections indicate a continued reliance on imported oil into the 21st century. Domestic production of oil and gas, on the other had, is projected to decrease from 50 to 55 percent of total energy supplied in 1975 to 1980 to 27 to 35 percent in the years 2000 to 2010. (See Table 2).

Domestically, the nation's production of oil and natural gas liquids peaked in 1970 and dry natural gas production peaked in 1973, reflecting depletion of older fields without discovery of new reserves sufficient to replace the oil produced. The decline was cushioned by production from the giant Prudhoe Bay oil field. If it were not for production from that field, U.S. production would have plummeted nearly 30 percent over the past decade instead of only 5 percent.

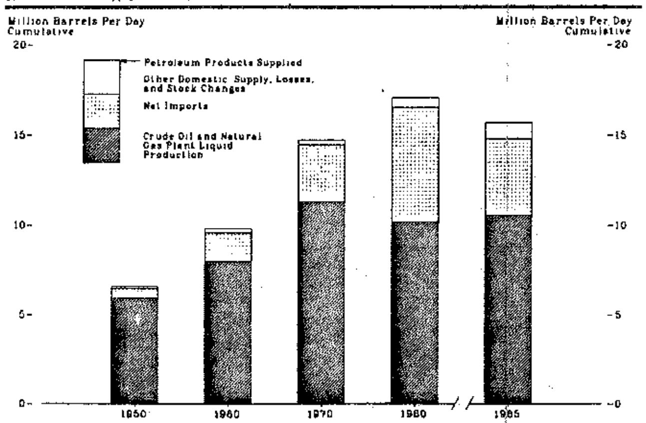
1/ These U.S. Department of Energy projections are based on their "Reference Case" assumptions, namely, the world price of oil in 1984 $/bbl of $26 in 1985, $23 in 1990, $37 in 2000, and $57 in 2010; economic growth projections for the period 1984-2010 are assumed to be 2.7 percent annually for the U.S. and 3.0 percent for the free world.

Figure 1
U.S. Energy Supply and Disposition




Source: DOE/EIA. Annual Energy Review 1985. Published May 1986, p. 4.

Figure 2
U.S. Petroleum Supply and Disposition




Source: DOE/EIA. Annual Energy Review 1985. Published May 1986, p. 100.



TABLE 2

OIL AND GAS ENERGY SUPPLIED TO THE U.S. ECONOMY

| | Total Energy Supplied to U.S. Economy *Quad Btu | Indigenous Production Oil *Quad Btu | Indigenous Production Gas *Quad Btu | Indigenous Oil and Gas as Percentage of Total Energy Supplied | Net Imports Oil *Quad BTU | Net Imports Gas *Quad BTU | Imported Oil & Gas as Percentage of Total Energy Supplied |
|---|---|---|---|---|---|---|---|
| 1970 | 68.3 | 22.9 | 21.7 | 65.3 | 6.9 | 0.8 | 11.3 |
| 1975 | 72.2 | 20.1 | 19.6 | 55.0 | 12.5 | 0.9 | 19.0 |
| 1980 | 78.3 | 20.5 | 19.9 | 52.0 | 13.5 | 1.0 | 19.0 |
| Projection | | | | | | | |
| 1990 | 87.3 | 21.2 | 18.0 | 45.0 | 12.5 | 1.4 | 16.0 |
| 2000 | 98.6 | 18.3 | 16.6 | 35.0 | 15.8 | 3.4 | 19.0 |
| 2010 | 110.8 | 15.6 | 15.3 | 27.9 | 17.6 | 3.0 | 18.6 |

* 1 Quadrillion Btu/year = 0.4724 MMBD (million barrels per day) of domestic oil
= 0.4696 MMBD of imported oil
= 2.649 billion cubic feet of natural gas/day

Source: U.S. Department of Energy: National Energy Policy Plan Projections to 2010, December 1985. Table 3-4 "Reference Case--Primary Energy Supplied to the U.S. Economy."

In 1985, U.S. domestic production of crude oil (including lease condensate) averaged 8.9 million barrels per day, up modestly from 1984, while production of dry natural gas was 16.38 trillion cubic feet (source: DOE/EIA Annual Energy Review 1985, p. 97, 145). The U.S. Department of Energy has projected an average annual 1 percent decline in total U.S. domestic oil production over the next 10 to 20 years. Total natural gas production is expected to decline, about 1 percent per year from 1990 to 2000. (See Figures 3 and 4).

U.S. proven hydrocarbon reserves have declined since 1970 by about 40 percent (See Figures 3, 4, and 5). Crude oil proved reserves stablized at about 28 billion barrels toward the end of the 1970 to 1985 period, however, this was a net loss of approximatly 37 percent from 1970. Natural gas reserves were at 197.5 trillion cubic feet in 1984, a net loss of approximately 47 percent from 1970. (Source: DOE/EIA Annual Energy Review 1985, p. 91). In 1984 proved reserves of crude oil increased 2.5 percent over the previous year while natural gas proved reserves decreased 1.4 percent over the same time period.

3. Imports

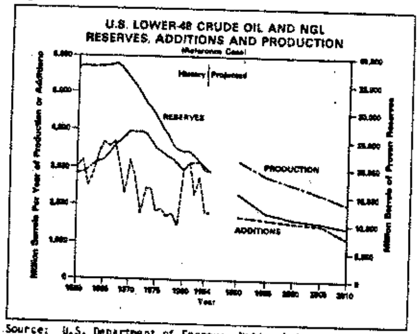
The oil embargo of 1973 and subsequent sharp price increases of imported oil which caused major disruptions in the U.S. economy in the past decade have resulted in a significant change in imports of oil to meet our oil and gas consumption needs. In 1980, we imported 14.65 quad Btu of crude oil and refined products, approximately 26.8 percent of our total oil and gas supply; in 1985 this category of imports equaled 10.55 quad Btu or 21.7 percent of our total oil and gas supply. (See Table 3). The figures in Table 3 present a breakdown of the source of supply of oil and gas to meet our consumption needs and reflect this decline in the overall role of imports over the past decade

In addition to the absolute and relative decline of imports, diversification of our supply by country of origin has also occurred. In 1977, 72.3 percent of our net imports of petroleum came from OPEC countries with the Arab members (Algeria, Iraq, Kuwait, Libya, Quatar, Saudi Arabia, and United Arab Emirates) supplying approximately half of that amount (source: DOE/EIA Annual Energy Review 1985, p. 113). In 1985 (preliminary data), 42.6 percent of our net imports came from OPEC countries with Arab members providing approximately one-fourth that amount (Ibid.). The diversification of our supply has resulted in increased imports from non-OPEC sources, namely Canada, Mexico, and the United Kingdom. Table 4 lists by country of origin our net imports of petroleum for the year 1977, when our reliance on OPEC oil was at its peak, and for 1985. This diversification of our foreign sources, completion of the Alaska pipeline in 1978, and the build-up of the Strategic Petroleum Reserve have left us less vulnerable to major supply disruptions such as occurred in the 1973 oil embargo.

Notwithstanding this trend, the United States will continue depending on oil supplies from abroad into the foreseeable future. The Department of Energy projects that in the year 2000, net imports (imports minus exports)

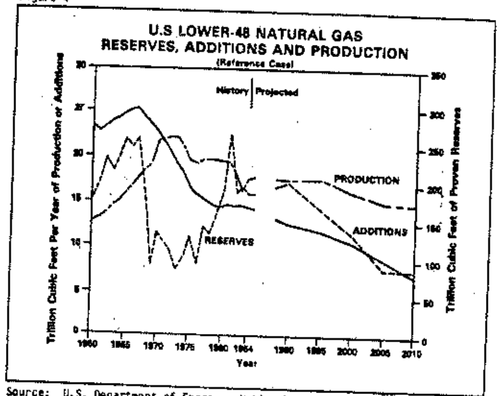


Figure 3



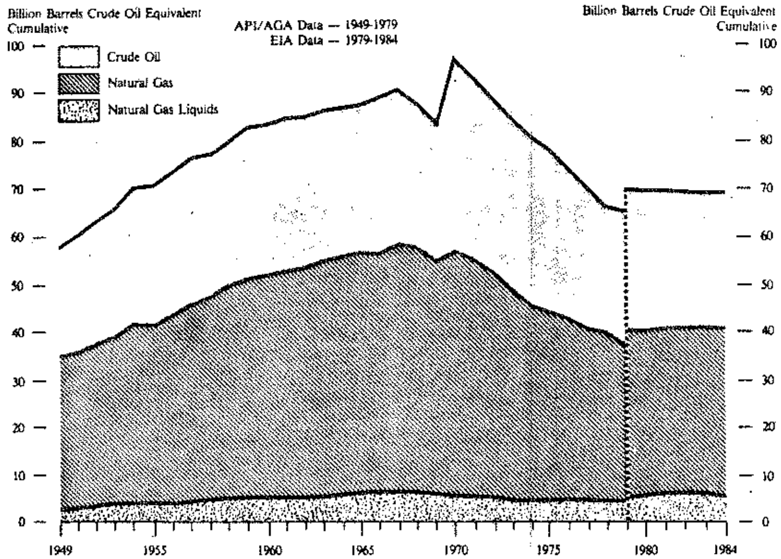

Source: U.S. Department of Energy: National Energy Policy Plan Projections to 2010, December 1985.

Figure 4




Source: U.S. Department of Energy: National Energy Policy Plan Projections to 2010, December 1985.

Figure 5
U.S. Domestic Proved Reserves of Liquid and Gaseous Hydrocarbon, Year-End, 1949-1984




Source: DOE/EIA. Annual Energy Review 1985. Published May 1986, p. 90.



TABLE 3

U.S. SUPPLY AND DISPOSITION OF OIL AND GAS

| | Quad Btu1/ | | | |
|---|---|---|---|---|
| | 1985 2/ | 1980 | 1975 | 1970 |
| **Supply** | | | | |
| Domestic Production | | | | |
| Crude Oil | 18.88 | 18.25 | 17.73 | 20.40 |
| Natural Gas Plant Liquids | 2.26 | 2.25 | 2.37 | 2.51 |
| Natural Gas (Dry) | 16.89 | 19.91 | 19.64 | 21.67 |
| Imports | | | | |
| Crude Oil | 6.83 | 11.19 | 8.72 | 2.81 |
| Refined Petroleum Products | 3.72 | 3.46 | 4.23 | 4.66 |
| Natural Gas | 0.93 | 1.01 | 0.98 | 0.85 |
| Adjustment | -0.90 | -1.53 | -0.99 | -1.59 |
| **Disposition** | | | | |
| Consumption | | | | |
| Petroleum Products | 30.85 | 34.20 | 32.73 | 29.52 |
| Natural Gas | 17.76 | 20.39 | 19.95 | 21.79 |
| Total Supply | 48.61 | 54.54 | 52.68 | 51.31 |
| Total Consumption | 48.61 | 54.54 | 52.68 | 51.31 |

1/ 1 quadrillion Btu/year = 0.4724 MMBD (million barrels per day) of domestic oil
= 0.4696 MMBD of imported oil
= 2.649 billion cubic feet of gas/day

2/ preliminary

Source: Derived from Table 1 "Energy Supply and Disposition, 1960, 1965, 1970, 1973, and 1975-1985", DOE/EIA Annual Energy Review 1985, May 19, 1986, p. 5.

TABLE 4

NET IMPORTS1/ OF CRUDE OIL AND PETROLEUM PRODUCTS BY COUNTRY OF ORIGIN 1977 AND 1985 (THOUSAND BARRELS PER DAY)

| Country | 1977 | 19852/ |
|---|---|---|
| OPEC: | | |
| Nigeria | 1,143 | 287 |
| Saudi Arabia | 1,379 | 167 |
| Venezuela | 689 | 606 |
| Other OPEC2/ | 2,978 | 756 |
| Subtotal (OPEC)3/ | 6,190 | 1,815 |
| Canada | 446 | 694 |
| Mexico | 155 | 754 |
| United Kingdom | 117 | 299 |
| Other Non-OPEC | 1,657 | 702 |
| Total Net Imports5/ | 8,565 | 4,264 |

1/ Imports minus exports.

2/ Preliminary

3/ Includes Algeria, Ecuador, Gabon, Indonesia, Iran, Iraq, Kuwait, Libya, Quatar, and United Arab Emirates.

4/ Arab members of OPEC include Algeria, Iraq, Kuwait, Libya, Qatar, Saudi Arabia, and United Arab Emirates.

5/ Figures may not add due to independent rounding.

Source: Derived from Table 51--Net Imports of Crude Oil and Petroleum Products by Country of Origin, 1960-1985, DOE/EIA Annual Energy Review 1985, May 1986, p. 113.



of oil and gas will constitute 19 percent of our total energy supply. Of the 54.1 quad Btu projected to be supplied by oil and gas, approximately 35.5 percent of that amount is projected to be imported in 2000 (DOE: National Energy Policy Plan Projections to 2010, Dec. 1985, Table 3-4). DOE projections (DOE/EIA Annual Energy Outlook 1985, February 1986, p. xxviii) indicate that the overall lower level of domestic production, combined with slightly higher petroleum demand is expected to raise net petroleum imports from 4.2 million barrels per day in 1985 to 7.7 million barrels per day in 1995.

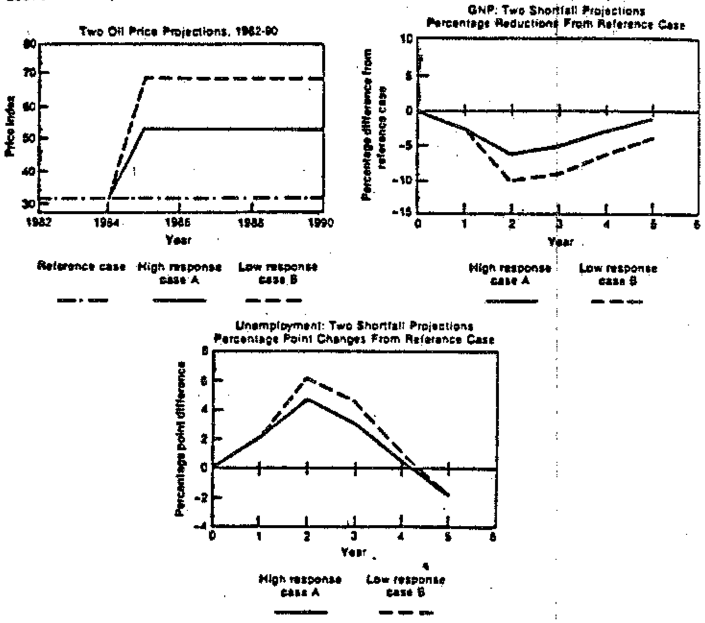
Although we have significantly decreased our imports of oil compared to the large volumes of the late 1970's and have diversified our foreign sources to minimize disruptive effects from an interruption to our supply, the vulnerability of the United States to an oil import curtailment still exists with potential resultant negative effects on our economic growth. A study conducted by the Office of Technology Assessment (U.S. Congress, Office of Technology Assessment. U.S. Vulnerability to an Oil Import Curtailment: The Oil Replacement Capability, September 1984) found that the United States has the technical and manufacturing capability to replace a 3 MMBD (6.3 quad Btu/day) shortfall within 5 years after the onset of a long-term disruption but not without increases in the price of oil and decreased level of economic productivity as measured by the GNP and domestic employment. The technological options which could replace the largest amounts of oil were increased efficiency and switching to alternative fuels to reduce oil use for space and water heating and for steam in industry and electric utilities, and increased average efficiency of automobiles.

Two oil replacement scenarios were developed by the Office of Technology Assessment which simulated the effects of a 3 MMBD shortfall on oil prices, GNP, and unemployment levels. Figure 6 graphically illustrates the effects of the "Case A" scenario which assumes an adjustment to the shortfall will occur within a 5-year period, and "Case B" which assumes a more constrained response. The average loss in GNP over the 5-year period is significantly less (40 percent) for Case A than for Case B, employment losses are 30 percent lower, and the oil price rise is about one-half as much.

The establishment of the Strategic Petroleum Reserve program by the Energy Policy and Conservation Act of 1975 recognized the need to buffer the effects of unforeseen events on oil supplied to our country. At the end of October 1986 Strategic Petroleum Reserve contained 508 million barrels of oil, which was equal to 107 days of non-SPR crude oil imports in that year. That compares with SPR stocks equal to 88 days of crude oil imports in 1982. (Source: DOE/EIA.)

Aside from the effects of a potential supply disruption, imports of expensive foreign oil reduce the economic well-being of the American people compared to the development of lower cost domestic sources such as the OCS. In 1985, the value of crude oil and petroleum products imports amounted to $48.27 billion. (Source: DOE/EIA Annual Energy Review 1985, May 1986, p. 31.)

Figure 6
Economic Comparison of Two Oil Replacement Scenarios




Source: U.S. Congress, Office of Technology Assessment, U.S. Vulnerability To An Oil Import Curtailment: The Oil Replacement Capability, September 1984.



To the extent that domestically produced hydrocarbons can substitute for higher cost imported crude oil supplies, the effect on our international trade account would be positive. Furthermore, Government revenues generated by OCS development and production result in lower Federal deficits, thereby putting less upward pressure on the dollar and indirectly contributing to a more favorable export climate.

As noted in the 1985 National Energy Policy Plan, an adequate supply of energy at reasonable costs "requires a flexible energy system that avoids undue dependence on any single source of supply, foreign or domestic, and thereby contributes to our national security." It recognizes further that the U.S. "is not independent of the energy supply circumstances of our allies abroad. The international dimensions of energy security and emergency preparedness are fundamental aspects of the definition of adequate supply for ourselves."

The development of OCS oil and gas resources contributes to our national security because of its potential to replenish our decreasing domestic reserve base and to displace imports. Availability of supplies within our national jurisdiction reduces our susceptibility to international supply disruptions. By adding to our domestically produced supply of petroleum, OCS oil and gas leasing provides a reliable component of this mix which contributes to our capacity to assist our allies in Europe and Asia. Even though we are less dependent on OPEC oil than our allies, we are still vulnerable to a disruption of OPEC exports. In such circumstances, all of our non-OPEC suppliers might well reduce oil shipments to us in order to honor their export contracts in an equitable manner. Through the International Energy Agency, the Organization for Economic Co-operation and Development (OECD), and economic summits, the United States has participated in developing collective energy requirements and establishing a framework for international energy security. The success of these arrangements is strongly affected by our ability to maintain a vigorous, carefully constructed OCS leasing program.

4. Effects of Declining Oil Prices

The time from December 1985 until July 1986 marks the steepest oil price slide in recent history. The U.S. Energy Information Administration (EIA) estimated the average world price of export crude oil for the week of July 28, 1986, at $9.46/bbl, compared with $27.10/bbl as of January 1, 1986. The price of oil will probably continue to be very unstable and could average anywhere between $10 and $20 per barrel for the year as a whole.

The collapse in oil prices that has occurred since the beginning of 1986 indicates that the oil market is in a state of transition that may prove to be just as significant as the oil price shocks of the 1970's. The immediate impetus for falling crude oil prices has been the recent major increase in production by OPEC--of nearly 3 million barrels per day during the fourth quarter of 1985. There also has been downward pressure on oil prices for the past 4 1/2 years, as a result of weak demand for oil products in the industrialized countries and a continued increase in crude oil production outside

OPEC. Sales of oil stocks in the consuming countries, in response to expectations of lower oil prices, have acted to reinforce the downward pressure on world crude oil prices. Captial changes in response to rapid decreases in oil prices include decreases or even disinvestment in the capital that responded to high prices and increases in investments in capital for producing other goods and services.

The suddenness and magnitude of the price decline from $30 a barrel to $10 a barrel has effectively capped non-OPEC production capacity for the forseeable future by discouraging exploration and development. Oil company budgets for these activities have been revised downward by 30 to 50 percent. A major portion of these initial cuts are directed at higher cost offshore exploration and development. All offshore development programs are under scrutiny and some costly GOM deepwater projects have already been postponed. Platform orders along the Gulf Coast have fallen by nearly 35 percent. Rig utilization in the Gulf, which was climbing toward 80 percent at the beginning of 1986, was 40 percent and dropping in mid-April 1986. Low oil prices tend to shut down the highest cost energy projects, such as exploring offshore fields, and owners will be wary of restarting until prices have remained firm for many months.

Despite these glum facts, concerns regarding the oil and gas industry's future willingness to invest the vast sums necessary for offshore exploration, development and production ignore the fact that the industry has traditionally made its investments under very uncertain economic conditions. Because the industry deals with long-lived assets, whose production revenues are generated over many years, firms are strongly influenced by their perception of the future, and they make investment decisions primarily employing projected values of future prices. Forecasts generally call for prices of at least $20 per barrel (in 1986 dollars) by 1990. After 1990, there is wide consensus in the professional macroeconomic forecasting community that prices will increase faster than inflation. Given the substantial number of leases due to expire in 1988 and 1989, it is likely that industry would find these price expectations sufficient to warrant numerous OCS investments. Consequently, the current decline in oil prices is expected to have only a temporary dampening effect on OCS activities, assuming reasonably similar price expectations are held by the industry. However, the history of the OCS leasing program shows how difficult it is for the Government to increase the availability of new areas for exploration in response to rapid increases in oil prices if the leasing program and procedures are designed only to make available the acreage worth exploring when oil prices are low and expected to remain so (See Appendix P). A shortened lag in response to the next oil price shock requires a program and leasing procedures geared to the rate of leasing that could occur if oil prices jumped. Leasing may not occur at the capacity provided for by such leasing rates, but the cost to the Government of such overcapacity is relatively small.

In a report entitled "The Impact of Lower World Oil Prices and the Alternative Energy Tax Proposals on the U.S. Economy" (dated April 14, 1986), the EIA compared energy import, consumption, and production levels assuming the 1985 Annual Energy Outlook (AEO) base case price path versus a case having prices $10 per barrel lower in each year. In the AEO base case, prices are assumed to be $23 per barrel in 1987 and 1988, then rise to $27 per barrel in 1990



and $30 per barrel in 1995. In the AEO low price case, prices are assumed to fall to $13 per barrel in 1987 and 1988, and then rise to $17 per barrel in 1990 and $20 per barrel in 1995.

During the 10-year period studied, total U.S. consumption of energy is projected to increase from 15.70 million barrels per day in 1985 to 16.12 (base case) and 17.05 (low case) in 1990, and to 16.60 (base case) and 18.15 (low case) in 1995. During these times, domestic oil production is expected to fall from 8.9 million barrels per day in 1985 to 8.1 million barrels per day (base case) and 7.2 million barrels per day (low case) in 1990 and to 6.5 million barrels per day (base case) and 5.0 million barrels per day (low case) in 1995.

Compared to 1995 levels, imports in 1990 are estimated to rise by 35 percent in the base case and by 80 percent in the low case. In 1995 the percentage increase in imports compared to 1985 levels is about double the increases estimated to occur in 1990. These dramatic increases in imports would likely help produce a rise in oil prices, resulting in renewed interest in drilling offshore areas. An important objective of the 5-year program is to ensure that leasing milestones in the 1987 to 1992 period are sufficiently flexible to accommodate this scenario, should it evolve.

5. The Economic Importance of OCS Oil and Gas

In the face of declining domestic proven hydrocarbon reserves and our dependence on foreign sources of oil, the hydrocarbon potential on the OCS represents a significant domestic energy source. In 1985, offshore oil and gas production represented 11.95 percent of total domestic oil production and 23.23 percent of domestic natural gas production. (Source: U.S. Department of the Interior, Minerals Management Service: Royalty Management Program. The average amount of unleased, undiscovered economically recoverable oil and gas resources on the OCS is estimated to be about 18 billion barrels of oil equivalent (BBOE). (See Table 5.)

The sources of these hydrocarbons are heterogenous in their location, their size, and their probabilities of being economic. Furthermore, an assessment of economically recoverable resources is dynamic over time based on the influence of factors other than the physical resource. Changing economic conditions, reflected in price changes, cost changes, and technological developments, influence the magnitude of our resource base in terms of its exploration and development potential. In addition, production of the resource ordinarily involves a time lag of 5 to 15 years from the time it is leased, indicating the need to address projections of oil and gas requirements in the future in formulating a leasing program today.

Consumers of oil and gas are concerned about the security and availability of the petroleum products they use and the prices paid for them. They have little specific knowledge of the source or cost of the particular oil and gas resources from which their purchases were produced. Consumers do know, however, based on recent experience that some of the crude oil is imported and that import disruptions can cause temporary shortages in the supply of petroleum products and potentially longer lasting increases in price.

Thus, it would seem from the consumers' perspective that the primary benefit of increased domestic oil and gas production, such as that sought by OCS leasing, is security of supply. Formulation of a leasing program based on security of supply would thus focus on the potential for discovery and production of more oil and gas resources without much consideration of economic factors. However, while security of supply is important, two factors make it reasonable to consider economic gains as well. First, all private investments leading to the production of oil and gas are made in response to potential economic returns. Oil and gas resources whose development is not expected to yield a sufficient return on such investments are not produced even though they might contribute to a larger supply of secure domestic oil and gas, at least for a number of years. Second, the economic efficiency with which we produce new OCS oil and gas may be as important as security of supply to our economic well-being. Further, national security itself can be enhanced by economically efficient development of our oil and gas resources. It is thus appropriate to consider economic benefits in formulating a leasing program.

The importance of economic efficiency can be illustrated by examining the role of oil and gas in our economy from the perspective of a resource owner and producer (which is the role the Federal Government performs on behalf of the public). The overall productivity of the U.S. economy, its ability to generate the income and the goods and services that we enjoy as consumers, depends on the success of many individuals and businesses in producing things that have value greater than the costs incurred. The bigger this difference, the greater the productivity of the U.S. economy and the higher our citizens' standard of living. The same principle holds for production of oil and gas. Economists call the allocation of resources that yields the greatest value an economically efficient allocation.

The economic benefit from producing OCS oil and gas instead of importing an equivalent amount can be seen by considering costs. The cost of an economic activity is the sum of the values of the various resources (labor, materials, energy) which are used in its conduct. The commitment of resources to one use usually excludes their use in the production of other goods and services. Since a market economy uses dollars to keep track of costs, the use of $20 worth of resources to find and produce a barrel of oil from the OCS means that at least $20 worth of other goods and services has been foregone. Similarly, if $30 is paid to a foreign country for a barrel of oil, then that country can remove $30 worth of resources or goods and services from the U.S. economy. The economic benefit from producing the OCS oil instead of importing oil is, in this case, the $10 of resources available to produce other goods and services for U.S. consumers that would not be available after importing the foreign crude oil. In more formal terms, the economic benefit of OCS oil and gas production is the difference between the production revenues valued at market prices and the costs of the resources used to find, produce, and transport to market the oil and gas produced.



As consumers, we cannot distinguish between gasoline made from imported crude oil and gasoline made from less costly OCS oil. Both sell at the same price and burn in the same way in our cars. As owners of crude oil resources, however, we can tell the difference between producing crude oil that costs more versus crude oil that costs less. Since both sell at the same price, a price determined by the world oil market and transportation costs, a low-cost oil reservoir yields higher profits to its owner than a high-cost reservoir. Higher profits to the owner mean correspondingly higher benefits to the economy whether the owner is a private firm or the Federal Government.

If all oil and gas accumulations on the OCS were to cost the same to find, produce, and transport to market, then the decisions leading to their development would tend to be all-or-nothing decisions. Either all of the deposits would yield oil costing less than expected prices and would be profitable to develop, or all would yield oil costing more than expected prices and none would yield any net economic value. However, the costs of producing OCS oil and gas deposits differ substantially depending on such factors as water depth, geological characteristics, the size and quality of the deposit, and site-specific difficulties in exploration and development activities. Some OCS oil and gas deposits have costs (appropriately calculated at time of production or in present value terms) of $5 per barrel, some $20 per barrel, and some $100 per barrel of oil recovered. Under given oil and gas prices and geologic risk, different oil and gas deposits yield different economic benefits because of the cost differentials.

If the cost of each deposit were known and future prices were known, it would be a straightforward task to determine which deposits would yield economic benefits and how much. Deposits with costs per barrel less than oil prices per barrel would yield profits for owners and producers, and benefits to the U.S. economy. Other deposits, which although taken together would probably contain much of the oil and gas in nature's endowment, would yield no profits and if developed at costs greater than prices would actually reduce the income generated by the U.S. economy.

This perspective of the economic gains from OCS oil and gas production can be applied to the objective of secure supplies. As will be discussed below, there is probably enough oil and gas in place within the United States (not to mention coal and other energy resources) to allow domestic production levels sufficient to reduce oil imports to zero. This fact makes energy independence a tempting goal. The reason the United States has not achieved complete energy independence is not that there are inadequate quantities of energy resources in the natural endowment of the United States. Rather it is that the economic and environmental costs that would be incurred in producing those resources are higher than the benefits of gaining a completely secure supply. While the security benefits of reducing imports are an additional gain to the direct economic efficiency benefits of OCS oil and gas production as defined earlier, there is a limit to the economic (and environmental) costs worth incurring to reduce oil imports. This limit might call for the development of some oil and gas resources that are not economical in terms of market prices and costs, but this additional development is not likely to allow the complete elimination of oil imports. Although the OCS leasing program is not likely to eliminate oil imports, it can help to bring about an economically appropriate amount of import reduction by allowing investments that reflect the different costs of oil and gas in various deposits.

Leasing OCS oil and gas resources is not as simple as merely deciding which deposits to produce and which to leave in the ground. Exploration and development decisions are continuously being made even as prices and costs change. Higher oil and gas prices make higher cost resources worth producing; lower world oil prices make investments in production of higher cost resources unprofitable and tend to reduce domestic production and increase oil imports. Since the production that results from leasing occurs over many years in the future, it is not oil and gas prices now or at the time of a lease sale that will affect production and economic benefits, but prices 10 to 30 years from now. Uncertainty about future prices makes it impossible to determine now precisely which unleased, undiscovered oil and gas deposits should or should not receive investments at any future point in time.

Despite this uncertainty, it is possible to develop a reasonable approach to formulation of a leasing program considering economic benefits. This approach emerges from the way exhaustible resources are generally developed. In the absence of international politics and other imperfections in world energy markets, there would be a tendency for oil and gas prices to increase gradually over the long run as demand was met from increasingly more costly deposits. (This tendency may be partly offset by technological developments that reduce costs, or it may be accentuated as world oil demand grows.) In general, there is a way of sequencing the development of oil and gas deposits of differing costs to yield the greatest benefits to resource owners (like the Federal Government) and to the economy as a whole. Such a sequence develops deposits in order of increasing costs, conserving higher cost resources for later periods when resource prices are higher because lower cost resources have been depleted. This concept of resource development will be discussed in more detail in section V.

It is an ironic fact that the benefits from an economically efficient sequence of OCS oil and gas resource development, given a path of world prices beyond our control, accrue to the American people primarily in their roles as owners of the resources on Federal lands, but not in their roles as consumers. Thus, while security of oil and gas supply is of concern to the public as consumers, the economic efficiency of producing our domestic supply is of concern to the public as owners of OCS oil and gas. A major consideration, therefore, in the formulation of a 5-year OCS oil and gas leasing program is its effect on the sequencing of economic activity involved in OCS development and the economic gains that result. Leasing programs that result in a sequence of development that is closer to the economically efficient sequence will yield greater benefits to the U.S. economy as well as greater revenues to the Federal Government.



The availability and price of oil on the world market are determined by a combination of factors, some political, some economic and some geological. Taken together, these factors will determine the costs to the U.S. economy of using imported oil at various times over the coming decades. They may also result in periods in which imports are curtailed, forcing the U.S. economy to operate without oil it would otherwise be able to purchase.

The amount of oil imported by the U.S., assuming that there are no supply curtailments, will also depend on a combination of factors and will vary with time. In general the total amount of oil demanded will decrease as prices increase and vice versa. Similarly the amount of oil and gas discovered and produced domestically will tend to be higher during periods of higher oil prices and lower during periods of lower oil prices.

The extent of discovery of additional domestic deposits depends, of course, on the nature of the oil and gas resource endowment. It may turn out that there are substantial deposits waiting to be found in higher cost areas. If so, when higher oil price expectations make investments in exploration in such areas worthwhile, these deposits will be added to the U.S. reserve base and will contribute to production. If it turns out that there are few such deposits, then investments in exploration will be dampened by the negative results of drilling and more oil will be purchased on the world market. Since changes in both demand and supply depend to a substantial extent on capital investment decisions, there is a time lag between changes in price expectations and changes in production and consumption.

The working of oil and gas markets thus will adjust the extent of U.S. imports to many factors. In general, during periods of lower world prices, the economy will use more oil, find and produce less and import more. The very conditions in the world market that seem favorable--ample and diverse production of oil and lower prices--can only be of maximum benefit to the U.S. economy if we import more oil, which, of course, makes the nation more vulnerable to supply curtailments and less well prepared for future price increases.

The question of how to spread our reliance on imported oil over coming decades can thus be seen as a question of balancing the economic productivity gained by using cheaper imported oil during times when world prices are lower against the potential costs of supply disruptions. Furthermore, it is quite possible that the total U.S. endowment of oil and gas resources will not be sufficient in amount and low enough in cost for production to keep pace with demand throughout the coming decades during which relatively low cost reserves in the Middle East and elsewhere are depleted. In light of this, Government policies could be used to shape, to a limited extent, the workings of the market and the allocation over time of domestic production and imports. Economic policies such as import tariffs, gasoline taxes or lower taxes on the oil and gas industry could shift some discoveries and their production to earlier times. A restrictive leasing program could shift discoveries and production to later times. At present there is no national policy that would provide the basis for substantial shifts of this sort in either direction. A leasing policy that would result in less exploration and production (with greater imports) in the short-to-medium term than would the workings of the market, implemented in order to have greater production (with less imports) in the long term, would need to be based upon an analysis showing that this would best meet the nation's energy, economic, and national security needs. To do so requires a more detailed examination of the nature of oil and gas resources, the workings of the market for these energy resources and the possible geopolitical scenarios that are likely to influence the available supply of imports.



## V. Resource Characteristics and the Economic Principles of Leasing

### A. Introduction

This section discusses the economic characteristics of OCS oil and gas resources and sets forth a general rule for sequencing their development that would maximize their contribution to the economic well-being of the citizens of the United States. This sequencing rule is developed first for a highly idealized situation. Then the discussion addresses the major differences between the actual and the idealized situation and the implications for Federal leasing programs.

### B. Resource Characteristics

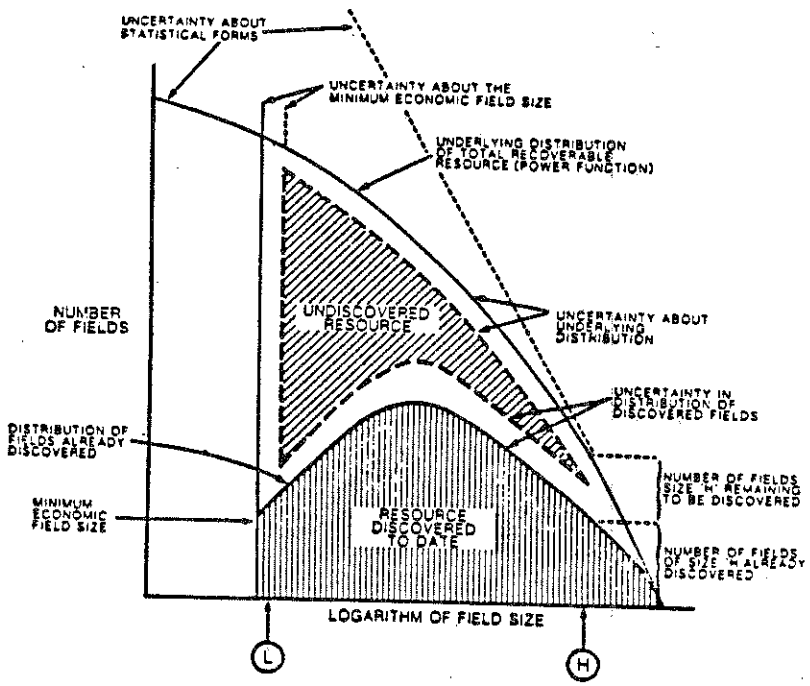
The physical and geologic characteristics of the oil and gas resources of the OCS are primary determining factors affecting their development and economic benefits. Oil and gas deposits (or fields) differ in many ways: the chemical and physical properties of oil and gas vary as do their proportions in a deposit; reservoirs differ in a number of characteristics that affect the ease of extracting oil and gas and the costs of production; the costs of basic operations such as drilling wells, installing production platforms, and transportation facilities differ from location to location; and the potential and actual amounts of oil and gas vary from deposit to deposit. For simplicity of discussion, it is helpful to focus on cost differences due to deposit size and location of the resource. This concept is described in more detail in the area-by-area analysis of resources and net economic value in sections VI and VII of this Appendix.

The results of oil and gas exploration in currently producing areas show a wide range in deposit sizes. For example, discoveries in the Gulf of Mexico out to 200 meters in water depth range from those with a few tens of thousands of barrels of hydrocarbons to those with approximately 1 billion barrels of hydrocarbons, varying by a factor of 100,000. In general, there are only a few giant oil fields, more medium-sized fields, and many more small fields in a hydrocarbon-bearing area. (A field, or in this discussion a prospect, is an area that is an actual or potential site of hydrocarbon deposits.) Figure 7 illustrates a schematic of the distribution of resources typical of a petroleum-bearing area.

Because of economies of scale, the cost per barrel of finding and producing oil generally decreases as the size of the deposit increases. Within an area in which the locational factors affecting cost are roughly the same, larger deposits will have lower per-barrel costs and higher net economic value per barrel. These relationships are shown in Figure 8. Area A in Figure 8 is the least costly location while Area C is most costly. At given oil and gas prices, the costs of operations in a particular area make oil and gas deposits which are smaller than the minimum economic deposit size uneconomical to find and produce. In lower cost areas such as the shallower areas of the Gulf of Mexico, relatively small deposits are economic while in higher cost areas such as Beaufort Sea, or the deepwater Atlantic, only the larger deposits are economic at prices within currently expected ranges.

FIGURE 7

SCHEMATIC REPRESENTATION OF CONCEPTS USED IN FIELD DISCOVERY MODELING




(H) ESTIMATE OF THE MAXIMUM FIELD SIZE

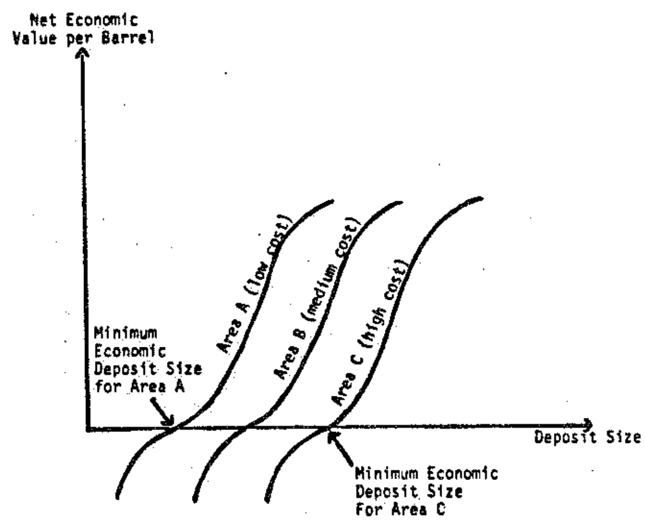
(L) ESTIMATE OF THE MINIMUM FIELD SIZE

Source: Frank Morra, Jr., and Stephan Peth. Short-term Projections of Offshore Petroleum and Natural Gas Production and Costs. Gas Research Institute, Chicago, Illinois. May 30, 1984.



FIGURE 8

GENERAL RELATIONSHIP BETWEEN DEPOSIT SIZE, COST REGIME, AND NET ECONOMIC VALUE PER BARREL



Because they yield greater returns on investments in exploration and because their size makes them easier to identify through predrilling exploration and more likely to be found, the larger deposits in an area tend to be discovered earlier in its exploration history. Figure 7 shows the population of resource deposits discovered after a substantial amount of exploration in an area. A far greater percentage of the few giant fields has been discovered than of the medium and smaller sized fields. In currently producing areas, the population of undiscovered resource deposits is probably depleted of giant fields, e.g., those with the highest net economic value as well as the most oil and gas. On the other hand, there are numerous medium and smaller sized fields yet to be discovered. Figure 9 shows the actual discoveries in the Gulf of Mexico in comparison to one projection of the total population distribution.

The unleased, undiscovered resources expected to exist in the various OCS areas differ for a number of reasons. Because of different geological histories, the population of deposits differs from area to area. In addition, the high costs of operations in some areas have made even the largest deposits in those areas uneconomic with the result that none have been discovered, while in lower cost areas it is likely that all of the giant fields have already been discovered. Finally, the history of leasing has allowed more leasing and exploration in some areas than in others. Since leasing tends to focus on the larger prospects first, just as exploration tends to find the larger deposits first, areas that have been leased extensively will tend to have a smaller portion of the population of larger and medium-sized prospects remaining to be leased than areas that have had relatively little leasing.

C. Economic Principles of OCS Investments

Concerns have been raised regarding previous leasing programs that oil and gas resources should be saved for future generations, that they should be left "on deposit" in the OCS, and that rapid offering of OCS acreage for lease could result in premature development of oil and gas resources. Such concerns can be addressed by considering the effects of the timing of production on the economic benefits realized from OCS oil and gas deposits.

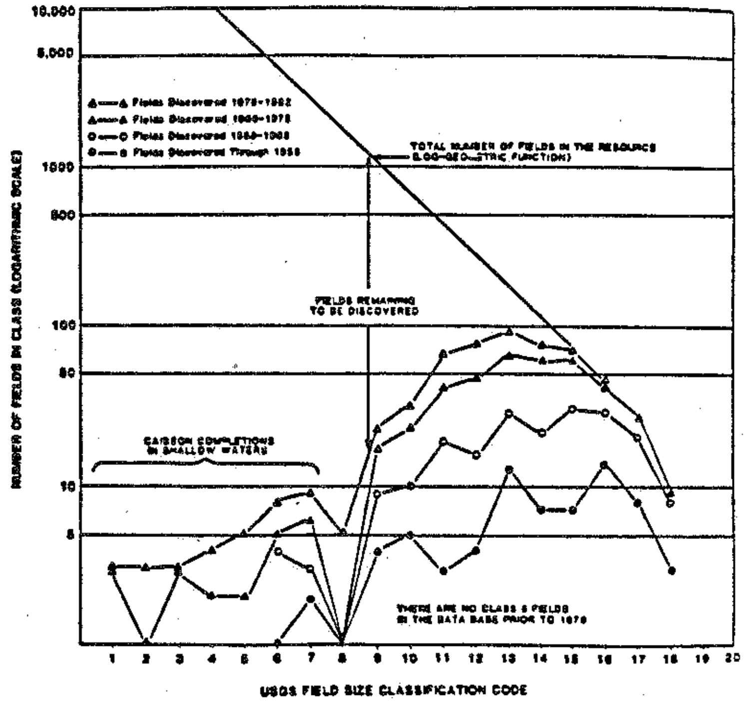
The basic concepts for analyzing these issues involve relationships among future oil and gas prices, the costs per barrel of the various deposits, and the time value of resources as measured by interest rates. The following discussion elaborates upon these notions.

Because oil and gas are exhaustible resources that are highly valued by society, their long term real prices can be expected to rise relative to renewable goods produced in our economy, until adequate substitutes are developed. For a given rate of oil price increase, the discounted net economic value (benefits) from production (i.e., the present value of revenue less production costs) of a particular deposit would increase or decrease if it were postponed, depending upon whether the deposit was high or low in costs. In general, the smaller the net benefit per barrel of production



FIGURE 9

DISTRIBUTION OF FIELDS THAT HAVE BEEN DISCOVERED AND REMAIN TO BE DISCOVERED IN THE GULF OF MEXICO




Source: Frank Morra, Jr., and Stephan Peth. Short-term Projections of Offshore Petroleum and Natural Gas Production and Costs. Gas Research Institute, Chicago, Illinois. May 30, 1984

Note: In the USGS field size classification, Class 8 fields have 380,000 to 760,000 BOE while Class 18 fields have 388.6 million to 777.2 million BOE. The upper limit for each class is twice the lower limit.

from a given oil and gas deposit at a given point in time, the greater the interest rate it will earn under a given path of future price increases. However, while high cost deposits with small per barrel net benefits earn relatively high interest rates today if left in the ground, as the accumulated interest swells the net benefit over time, the interest rate (i.e., the growth rate in net benefits) decreases.

These effects can be illustrated by a set of simple examples. In the first, oil can be produced at $28 per barrel from a deposit. If the price of oil is $30 in the current year, the net economic value of this oil is $2 per barrel. If oil prices are expected to increase at 1 percent per year, then the net economic value of this oil if production is delayed is $2.30 ($30 x 1.01 - $28) per barrel in the second year, $2.60 ($30 x $1.01^2$ - $28) in the third year and so forth. The effective interest earned by leaving oil in this reservoir on deposit in the ground is 15 percent (0.30 ÷ 2.00 x 100) in the first year. However, even though the net economic value increases rapidly (from $2.00 in the first year to $4.16 in the eighth year), because the interest payment increases slowly (from $0.30 in the first year to $0.32 in the eighth year) the effective interest rate declines. In the second year, leaving oil on deposit yields 13 percent (0.30 ÷ 2.30 X 100) while in the eighth year, postponing production for a year yields only a 7.7 percent (0.32 ÷ 4.16 X 100) gain in economic value.

A second example illustrates the situation for lower cost oil. If oil can be produced at costs of $20 per barrel and sold at $30 per barrel, then the net economic value is $10 per barrel. For oil from such a deposit, postponing production for a year while oil prices increase 1 percent to $30.30 per barrel yields a gain of only 3 percent. Generally, such a deposit should be put into production immediately. While these examples are highly simplified, they show the significant differences in the gains in value that result from leaving economically recoverable oil of different benefit to the country on deposit in the earth while oil prices increase. (If oil prices are expected to remain constant or decline for an extended period of time, the direct economic benefits of leaving positively-valued resources on deposit may be eliminated.)

An imaginary manager of all the deposits on account in the OCS bank with the authority to leave them or withdraw them for reinvestment at any time could reasonably use the following logic in making such decisions. The U.S. economy yields a return on resources of, for example, 8 percent. This is one accepted value for the discount rate used in the Government's economic decisionmaking. Any deposit in the OCS that would earn more than 8 percent interest under the oil price expectations at a given time should be left in the OCS bank. Any OCS deposit yielding less than 8 percent effective interest should be withdrawn from the bank and its value invested in the economy instead. In the examples above, oil from the $28 per barrel reservoir would be left in the ground until the eighth year while the oil in the $20 reservoir would be produced in the first year.



An OCS manager in this highly idealized situation would reap the greatest economic value for the nation's economy by keeping an inventory listing of each OCS oil and gas deposit with estimates of its benefits if developed beginning in the present, and the rate of growth in its benefits that would result from postponing development under expected future oil and gas prices. As oil prices increase, formerly uneconomic deposits become economic. Whenever the growth rate on a given deposit's net benefits dropped below the discount rate, it would be economically producible and the manager would take action to bring about development of that deposit. This concept is in keeping with the theories of optimal development of exhaustible resources that have emerged in the economics profession during the 50 years since Hotelling's seminal paper (H. Hotelling, "The Economics of Exhaustible Resources," Journal of Political Economy, 39, April 1931, pp. 137-175).

It is worth noting that while the sequence of oil and gas development that would result from application of this principle would be the most beneficial to the U.S. economy, it would not result in very large net economic values measured at the time of development unless there had been unanticipated, abrupt increases in oil and gas prices, abrupt decreases in costs or unexpectedly positive new geologic information. The reason for this ironic result is that the benefits from developing a deposit cannot become very large before a given gradual oil price increase fails to yield a growth rate that is less than the discount rate.

To demonstrate, suppose that oil costs $20 per barrel to find and produce, and real oil prices rise by 1 percent per year. When the starting oil price is $22.86 per barrel, the first year's growth in net economic value per barrel is 8 percent. In subsequent years, the annual growth rate in net economic value will decline, e.g., to 7 percent 3 years later. Under these conditions a rational manager of OCS deposits trying to maximize the economic gains from their production would not let the benefits from a given deposit grow past the point at which their growth rate is less than the discount rate; in this example, that occurs when the oil price reaches $22.86 per barrel.

Before discussing the effects of uncertainty about resource deposits and economic conditions, several important features of this idealized rule for managing OCS oil and gas resources are worth noting. First, as long as oil prices or costs or both are expected to change, production of OCS oil and gas resources are never final go/no-go decisions for all of the oil and gas endowment of the OCS or of a given planning area. Rather, decisions are made which sequence the production of many different deposits over a long period of time.

A second important feature is that the resulting sequence of oil and gas development and production saves an economically appropriate and potentially large amount of the OCS oil and gas endowment for production and consumption by future generations. This conservation of oil and gas resources for future generations results directly from the economic rule for sequencing the production of various deposits. Such conservation, however, is not readily apparent in most discussions of resource scarcity and development. In the idealized situation for which the rule was developed, the OCS manager has a known inventory of all the oil and gas deposits in the endowment. At a given point in time, he could group these deposits into three groups:

A. Uneconomic deposits: those that are not economical under the prices expected during the upcoming production period. (Costs exceed price on these deposits.)

B. Marginal economic deposits: those that are economical but whose net benefits are growing at a rate greater than the discount rate.

C. Economic deposits: those that are economical and whose net benefits would increase at a rate less than the discount rate.

The idealized manager would bring the deposits in group C (economic deposits) into production in the current period under the rule of sequencing. He would save deposits in group B (marginal economic deposits) for development within a relatively few years. The uneconomic deposits in group A would be postponed from production for many years or decades as seen from the manager's current decision point. A manager who knew the amount of resources in group A and the costs of production from the deposits containing them would be able to give a clear picture to current generations of the amount of resources which would remain for future generations.

A third feature of resource management by the designated sequencing rule is that it yields the economically most beneficial sequence of development and production for a given path of future oil and gas prices and operating costs. Actual price changes also can be reflected in the manager's subsequent decisions using the sequencing rule even if these prices have not followed expectations.

Because of the abrupt and unanticipated oil price changes of the last decade or so, it is worth examining how a manager using this sequencing rule would react to such price changes. Assuming that the sequence of development prior to a price increase has followed the rule, the manager would have his inventory of nonproducing oil and gas deposits divided into groups A, B, and C as described earlier. An abrupt and unanticipated increase in oil prices, assuming that it would raise prices throughout the upcoming production period but leave the rate of price increase during that period unchanged, would cause him to regroup his deposits. Numerous deposits would be shifted from group B to group C because they would now yield such great net benefits that future price increases would not increase them at a rate greater than the discount rate. Of course, deposits that were already in group C would now yield even greater benefit from production than anticipated when they were first classified as ready for development. In addition, some of the uneconomic deposits in group A, those that were close to being economical before the price increase, would be shifted to group B. A large enough price increase could make some deposits that were uneconomic shift directly from group A to group C.

The effect of an abrupt and unanticipated oil price increase is thus to greatly increase the number of deposits economically ready for development and to substantially increase the net benefits which the economy can realize from the production from these deposits. The manager under these conditions would reasonably be expected to substantially increase the pace of development in order to realize these net benefits.



Other unanticipated changes in oil prices could occur. For example, some external factor could cause an increase in the long run rate of oil price growth. This would cause shifts in the grouping of oil and gas deposits similar to the abrupt price increase scenario, but the increased long-term price growth rate would reduce the extent of shifting from group B to group C. A higher rate of future oil price increase means that the optimal time for bringing a given deposit into production would be later. A very large increase in the long-term rate of future oil price growth could, in fact, shift some deposits from group C to group B for a period of time.

Recent price trends in the world oil markets show the possibility of a decrease in the rate of future oil price growth. If the OCS manager were confronted with an unanticipated leveling off of oil prices for the coming production period after expecting continued increases, he would find it necessary to regroup his inventory of deposits, moving some from group B to group A and some from group B to group C. The deposits moved to group A would be those that were barely economical given the higher prices that were expected later in the production period. Without such continued increases, such deposits become uneconomical.

On the other hand, some deposits that were increasing in value under previously expected price increases would be shifted to group C because there is no longer any increase in the economic benefits to be had by waiting for higher prices. Thus, an unanticipated leveling off in the rate of future price growth, like an abrupt, unanticipated increase in prices, could bring the OCS manager to order an increased number of deposits into production in order to achieve the greatest gain for the economy.

In the previous discussion of the ideal sequencing and timing of investments and the resulting production from the various oil and gas deposits of the OCS, two assumptions have been implicit: (1) that oil and gas prices adequately reflect the value of oil and gas to the U.S. economy and (2) that the costs incurred by lessees adequately reflect the costs to society of exploration, development, and production activities. It is likely that there exist benefits from domestic oil and gas production that are not well reflected in world oil prices as well as social costs that are not reflected in the market costs of oil and gas operations. The social costs are analyzed in Appendix I. The possible external benefits (or positive externalities, as economists call them) from producing oil and gas and reducing oil imports have received growing attention during the past five years.

The concept of an "oil import premium" was formulated in the 1970's for the purpose of analyzing the economic impacts on the domestic economy from changes in the U.S. demand for imported oil. Potentially the most important component of the premium is the effect of changes in U.S. demand on the world price of oil. Additional effects involve changes in inflation rates, balance of trade measures, and national security considerations, none of which are reflected in the oil price. For our purpose, changes in the demand for imports emerge from changes in OCS production. Hence, for each potential barrel that might be generated domestically, the import premium can be added to the net economic value of a marginal barrel to obtain the total economic value of replacing imports with OCS supplies.

Suppose that, in the world oil markets, elasticity of demand is -0.4, while elasticity of supply is 0.1.* These figures are consistent with those used by Horwich and Weimer and other analysts in the mainstream of the issue. (See Horwich, George and David Leo Weimer. Oil Price Shocks, Market Response, and Contingency Planning. American Enterprise Institute, Washington, D.C., 1984. p. 72.) If oil prices are at $30 a barrel and world oil production is 50 million barrels per day (Mbbl/d), a one barrel increase in production can be shown to cause the market price to drop by $0.0000012 to $29.9999988 per barrel. But for the market as a whole, the $0.0000012 multiplied by 50 Mbbl/d translates into $60 less being paid worldwide by consumers for their oil and $60 less being taken in by producers.

When the analysis is restricted to one importing country instead of the world, some of this $60 can be included in valuing the marginal barrel supplied. If U.S. imports are running at 5M bbl/d, then the fall in price resulting from the additional barrel of domestic supply means that U.S. consumers will be paying as a group $6 less to foreign producers. If marginal domestic production costs are $10 per barrel, the incremental barrel produced is worth $26 to the United States, not just $20 ($30-$10 + $6). The extra $6 is the marginal import rent (or marginal price effect of the import premium). This transfer from foreign producers to consumers is spoken of as a transfer of economic rent. If supply increases or demand falls, the market price falls, and there is a transfer of rent from producers to consumers; if supply decreases or demand increases, there is a transfer the other way.

In addition to the import rent effect discussed above, other components have been identified which measure a more comprehensive "import premium." One is a "disruption component," extending the import rent analysis to allow for different import levels and supply and demand sensitivities during a supply disruption, given certain levels of public and private inventories. To the extent that additional domestic production substitutes for imports, the effect of price changes in oil markets as well as secondary effects in other markets may be dampened during a supply disruption. Indeed, with a reduction in imports, both the likelihood of a disruption itself and the required size of the public stockpile may be reduced (or the protection afforded by the existing stockpile might be increased). For a long-run increment in oil supply, the value of the marginal import rent would have to be adjusted for the proportion of the increment's lifetime that could be expected to be affected by disruptions, and the value to the economy from reducing the disruption and inventory costs.

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* The relationship between prices and quantities supplied or demanded is often expressed in the form of an "elasticity". A demand elasticity of -0.4, for example, means that consumers will want 0.4 percent less oil for every 1 percent increase in oil prices. A supply elasticity of 0.1 means that producers will want to produce 0.1 percent more oil for every 1 percent increase in prices.



Other components of the import premium incorporate various macroeconomic effects. One, an inflation component, translates import demand reductions into an effect on the inflation rate and then back to a measure of national income for the effect per incremental barrel produced. Another major macroeconomic component measures a balance of payments effect, which is the improvement in the balance of trade resulting not from any rent transfer nor from the change in oil prices but rather from the effect of incremental domestic supply on the aggregate import bill and subsequently on another measure of national income. Both the inflation and balance of payments components are somewhat controversial, requiring seemingly speculative assumptions and possibly involving some double counting.

Taking into account these various conceptual components, some analysts have estimated import premiums as high as $124 per barrel. (See: Broadman, Harry G. Review and Analysis of Oil Import Premium Estimates, Discussion Paper D-82C. Resources for the Future, Inc., Washington, D.C., 1981. p. 5-2.) Other analysts, however, exclude the macroeconomic effects, focusing instead on the market effect of a reduction in U.S. import demand (from incremental domestic production) on world oil prices. Their conservative estimates of the premium are generally below $10 per barrel. (See: Bohi, Douglas R. and W. David Montgomery. Oil Prices, Energy Security, and Import Policy. Resources for the Future, Inc., Washington, D.C., 1981. p. 134.)

Considering the range of estimates and the difficulties in arriving at realistic assumptions, a precise quantitative measure of the import premium is not very trustworthy. It should be noted, however, that the estimates of Net Economic Value in this Appendix are conservative because they do not incorporate any amount for the value of the import premium.

In deciding the timing of investments in oil and gas prospects on the OCS, the idealized manager would thus need to add estimates of the external benefits to estimates of net economic value. At a given point in time, this would affect all prospects being considered for investment by increasing oil and gas prices. If the import reduction premium were expected to increase over time because of the expectation that oil prices or imports or both would increase, then the manager's forecast of future oil and gas price trends could be adjusted appropriately. By calculating benefits using prices adjusted for the effects of the import reduction premium, all of the observations of the previous discussion based on prices, benefits per barrel and costs then hold. The sequencing rule then can be applied using estimates adjusted for the import reduction premium.

At this point in the discussion, the question of the timing over coming decades of production and imports can be addressed once more. Assuming that the idealized manager had properly estimated the import reduction premium for future years, his application of the rule for determining the timing of investment in each prospect would yield exploration, development, and production that would best meet the Nation's energy and economic needs. In particular, it might shift oil and gas production from periods in which it would be best based on market prices alone to other periods when it would be best based on market prices and the import reduction premium combined.

Although it is quite difficult to estimate the import reduction premium for future years, it is possible to assess its general relationship with regard to possible future scenarios. The adjustments to the ideal path of development resulting from market prices alone can then be assessed. For example, if the import reduction premium is currently rather small, but is expected to grow significantly over the next two or three decades, then the adjusted base prices for calculating benefits would be little different from current market prices, but the rate of adjusted price increase would be greater than the rate of market price increase. In general, for some prospects, the time at which they are mature for investment would be shifted to later years by such an adjustment. This situation might result if the economy was expected to become gradually more vulnerable to import disruptions over coming decades. This could emerge from the failure to develop : (1) more energy efficient capital, (2) more efficient substitute energy supplies, (3) oil and gas reserve bases sufficient to keep imports from growing, or (4) strategic petroleum reserves sufficient to offset the effects of an import disruption. The more likely such a scenario were to evolve as time passed the more an idealized manager of the OCS would stretch out investments in prospects with high unit costs.

It is possible that the trend in the import reduction premium could be flat or even declining. This would reflect expectations that the economy would continue to develop a capital structure that is more energy efficient and that allows substitution of alternative energy supplies. Or it could reflect a judgment that the likelihood or size of an import disruption was decreasing over time. A flat, moderate import reduction premium would require little adjustment in the timing of investments and production on the OCS. A declining premium would require somewhat earlier investments in some prospects.

Although this discussion has offered no definitive answer to the issue of the best timing of investments and resource depletion, it has at least provided some insights by relating an idealized management rule to some of the trends which affect the future. Subsequent discussion will address the role of market decisions in the same framework.

The Secretary, as manager of the oil and gas resources of the OCS, confronts an actual situation that makes it impossible to follow exactly the course of an idealized manager. By examining the differences between the actual and idealized situation, it is possible to develop a reasonable adaptation of the idealized priciples of leasing.



Imperfect knowledge of oil and gas resources is an inherent limitation in managing OCS oil and gas resources. Oil and gas deposits on the OCS are hidden from view under hundreds or thousands of feet of water and thousands of feet of the earth's crust. Actual deposits can only be discovered through drilling costly exploratory wells. Prospects, which are geological features that could contain oil and gas deposits, can be identified through the analysis of seismic data. Given the large area of the OCS and the relatively small area of most prospects, substantial cost is incurred in identifying prospects. Seismic surveying and exploratory drilling are the basic investments that are made in the search for oil and gas. They must be made with the recognition that often they will not yield discovery of oil and gas deposits. Many prospects are identified that, on closer evaluation, do not warrant an investment in exploratory drilling. Many prospects that are drilled turn out to contain no oil and gas. Others are found to contain oil or gas but are not economically producible because of the size and character of the deposit. In addition, individuals and groups differ in identifying and evaluating prospects. Many prospects go unseen through numerous seismic surveys and evaluations. Others are identified by only one of the many firms searching an area.

In the idealized situation described earlier, the OCS manager had a known inventory of all deposits. In actuality, the Department of the Interior has an incomplete and uncertain inventory, not of actual deposits, but of identified prospects and aggregate resource potentials. Where the idealized manager saw deposits shifted within his inventory depending upon economic expectations, the actual inventory of unleased, undiscovered recoverable resources also changes over time as the state of knowledge evolves from investments in seismic evaluation and exploratory drilling. The search process continually adds prospects to the inventory as they are identified, drops them as they are leased or condemned by further seismic evaluation or drilling, and recharacterizes their resource potential and costs. Thus, the actual knowledge of OCS oil and gas resources on which leasing decisions are based is not final or definitive.

One important limitation on knowledge of oil and gas resources is the lack of data on very high cost (per barrel) deposits. In particular, almost nothing is known about the uneconomic resources in group A. They are excluded from estimates of "undiscovered recoverable resources" such as those published by the U.S. Geological Survey, MMS, and oil companies, because they are not economically recoverable. In fact, since resource information is a by-product of investments in the search for economically recoverable oil, little data exist on deposits having costs substantially greater than the highest price expectations on which such investments have been based. Many of the areas in which group A deposits are located have such high operating costs that they have received only a cursory analysis of their resource potential. Yet precisely because of their high costs, application of the rule for the sequencing of development conserves the resources of these areas for future generations. However, owing to the shortage of reliable information about the extent and location of these resources, they do not greatly influence the planning of future exploration and development. Since the extent of the resource saved for future consumption is not evident, the concern about conserving acreage for the future focuses on currently economic resources.

If the information needed for the idealized inventory were costless to acquire, then there would be no reason not to compile a perfect inventory and manage development accordingly. Unfortunately, the advantages gained from a perfect inventory are not likely to exceed the very substantial costs of getting one. Thus, given the substantial cost of investments in seismic evaluation and exploratory drilling, it is appropriate to seek a sequencing rule under uncertainty that parallels the sequencing rule set forth earlier for investments necessary to bring known deposits into production. It is not difficult to show that, assuming independence among prospects, the optimal sequencing rule in the presence of uncertainty is directly analogous to the case of certainty. To maximize the long-term average economic benefit, investments should be ordered with reference to current and future expected (average) net economic benefits.

Expected value is the economist's term for an estimate that reflects both the values of all the possible outcomes of an investment and their probabilities. Since experience in the search for oil and gas deposits generally allows analysts to characterize the outcomes and probabilities for a given prospect, its value can be expressed as an expected value.

A simple example is useful to illustrate the calculation of expected value. The flip of a silver dollar has a 50-percent chance of coming up heads and 50-percent chance of coming up tails. If the dollar is won on heads and nothing lost on tails, then the expected value of the flip is $0.50 (0.5 x $1.00 + 0.5 x $0.00).

For prospects that have been identified, it is possible, though still costly, to estimate their expected value. Such estimates can reflect the possible outcomes and their probabilities for all key parameters on which value depends, including future prices and costs, the resource's geologic magnitudes and risks, and the discount rate.



Discount Rates and Timing of Investments

The analysis in this program document employs a range of discount rates between 6 to 8 percent. The choice of a discount rate to use in estimating the economic value of offshore oil and gas resources is an issue on which economists have not reached a consensus. Comments on the proposed 5-year program include the contention that the energy industry's cost of capital is greater than that of the Government's cost of capital, and that the 8 percent (public) discount rate used in the analysis is too high.

The common assumption is that the correct discount (interest) rate is the social rate of time preference, which reflects how society as a whole weighs the tradeoffs between present and future consumption. Two fundamental aspects of the way in which time affects resource values are captured by this discount rate: first, the way in which society values economic productivity in the short run (say, the next 5 to 10 years) as compared to economic productivity in the long run (say 10 to 50 years) and second, the returns inherent to the gains in future economic productivity that are expected from other investment opportunities. In general, the more the American people are willing to give up consumption in the short run in order to have greater consumption in the long run, the lower will be the discount rate. One would not have to pay very high interest rates to achieve high savings rates in this situation. On the other hand, the greater the returns from other investment opportunities, the higher will be the discount rate. Firms will be willing to borrow at higher interest rates because their investments yield higher returns.

Since financial markets work to bring savings and investment into equilibrium, the ideal discount rate is the interest rate that would be observed in well-functioning financial markets. Interest rates can be thought of as the price of capital. As in any market, the price will be determined by the interaction of supply and demand.

The supply of capital arises from individual members of society. Out of each dollar of income, each individual allocates a certain proportion for immediate consumption, and the rest is saved. The amount saved depends on a number of factors, including: current and expected future income, current and expected future consumption needs and desires, the level of each individual's concern for the welfare of his children, and the nature of savings opportunities, available now and in the future. The result is the supply of capital.

Demand for capital depends on the range of investment opportunities. For an individual, the demand for capital is derived from the same factors discussed above, but his decision is, in effect, negative saving--borrowing against future income for current consumption. A corporation will look for opportunities that will provide a rate of return at least as high as the cost of the capital employed. The investor's view of investment opportunities depends on his perception of present and future economic growth, technological progress, distribution of wealth, and consumer preferences, among others.

The discount rate results from the equilibrium between savings and investment. A combination of a high level of savings and a low demand for investment capital will lead to a low discount rate. People's preference to save for future consumption will result in less present consumption in general and less energy consumption in particular. The OCS will be developed at a slower pace by our idealized manager because fewer deposits have benefits growing slower than the discount rate, given a rate of price increase. Strong demand for capital combined with a low level of savings will result in a high discount rate. The pace of OCS development will quicken because the manager will have a greater number of deposits with benefits growing slower than the discount rate. Other combinations of savings and investment demand will lead to a development pace between those of the two examples.

Unfortunately, there is not a single equilibrium interest rate in the economy. The interest rates that can be observed in the market are the rate of return on capital and the consumer's rate of interest. The former is the minimum rate of return required by an investor to undertake a project, or the interest rate cost of the capital employed in the project. The consumer's rate of interest reflects how individuals decide between consumption and saving, and is revealed by the interest rates at which consumers can borrow or save money. The problem is to decide which, if any, of these observable interest rates best approximates the social rate of time perference.

In the ideal world of economic theory, all of these interest rates are identical. Actual capital markets, however, contain a number of imperfections that cause the various interest rates to diverge from each other.

First, observed market rates of interest are distorted if markets are not in perfect equilibrium. The presence of unemployment, for example, indicates that markets are not functioning perfectly, and therefore that observed quantities, like prices and interest rates, are not at their ideal level. Second, some benefits and costs, such as information benefits and environmental costs, are not captured in market transactions, so market prices do not reflect actual social values. Third, the Government may directly influence the level of interest rates in the market through fiscal and monetary policies and create industry-to-industry variations in the rates of return through regulatory and tax policies. Even within an industry, taxation produces differences between before tax and after tax returns, which further complicates determinations of the proper discount rate to be used for addressing OCS policy issues.

Another source of variation in observed rates of interest is risk. The rate of return earned by investors usually increases with the amount of risk inherent in the project. This has led some economists to propose that the Government should use the discount rate that is employed by the private sector in considering projects of similar risk. In the case of OCS development, the Government would use the same discount rate that the energy industry employs. Other economists argue that the government benefits from risk-pooling,



in which the government's investment portfolio is so large that the incremental risk from one additional investment is negligible, and risk is spread over the entire population so that the risk to any member of society of negligible. This argument suggests that the government should employ a discount rate that does not incorporate risk.

Finally, it has been argued that capital markets do not appropriately reflect the preferences of future generations. Some economists contend that a lower discount rate should be used because individuals systematically undervalue the consumption of future generations. People give greater weight to the consumption of contemporaries and immediate descendants than they do to the consumption of more distant future generations. Even if this were not the case, the interest rates observed in the market reflect only individual's preferences with respect to their own consumption. Individuals as members of society would choose a discount rate lower than the rate they choose as consumers.

Other economists argue that the welfare of future generations may be better off than the present generation, thus, not requiring an exogenously determined lower discount rate than those observed in the market. For example, Joseph Stiglitz states:

> One should not view equity in a narrow sense of simply looking at the division of natural resources between present and future generations; the present generation may give future generations fewer natural resources (this is inevitable in the case of exhaustible natural resources), but it will give future generations a higher level of technology and more capital. One has to look at the relative welfare of the different generations and there is a strong presumption that future generations may be better off than the present generation. On grounds of equity it might be argued that we should consume even more now (including more natural resources). (J.E. Stiglitz, 1979, "A Neoclassical Analysis of the Economics of Natural Resources," in V.K. Smith, ed., <u>Scarcity and Growth Reconsidered</u>, Baltimore: John Hopkins University Press, p. 61).

All of the preceding factors cause market interest rates to diverge from each other and from the ideal social discount rate. Individually, these factors can drive observed interest rates either above or below the social rate of time preference. As a group, their net effect is unclear, and the relationship between market rates of interest and the social discount rate is not well defined. (For a more complete review of the discount rate issue, see Robert Lind, et. al., 1982, <u>Discounting for Time and Risk in Energy Policy</u>, Balitimore: Johns Hopkins University Press.)

Comments have been suggested that an appropriate rate of discount is the interest rate on Government bonds because this rate represents the opportunity cost to the Government of raising funds. This argument presumes that there is a one-to-one correspondence between Federal OCS revenues and Government borrowing. In other words, every dollar of Federal OCS revenue replaces exactly one dollar that the Treasury would otherwise have borrowed. If this were the case, the interest rate on Government bonds would be the correct discount rate for analyzing the revenue effects of OCS leasing.

It does not appear, however, that a one-to-one correspondence exists. If OCS revenues were to decline, the Government might choose to increase taxes and reduce spending in addition to increasing amounts borrowed. The degree to which these alternative sources of funds are utilized has attendant and different effects on the economy. Taxation alters the consumption and investment patterns to a degree that depends on both the distribution of the tax burden and the distortional incentives on spending. Government expenditures can be targeted both toward current consumption and social investments with future payoffs.

To the extent that Federal OCS revenues offset taxes or augment expenditures, the discount rate used to analyze the revenues must reflect the interest rates that are inherent in the consumption and investment effects in the economy. The interest rates or opportunity costs associated with these activities are higher than the rate on Government bonds. Thus, a social discount rate chosen solely on the basis of Government borrowing would be too low.

In deciding upon the proper discount rate to use in managing the OCS program, it must be recognized that the decision variables (e.g., leasing rate, sale size, sale locations, etc.) do not mandate the displacement of private consumption or investment with public funding. Hence, unlike a decision to build a highway or dam, the decisions for an OCS program that lead to capital investments are undertaken voluntarily by the private energy sector. Moreover, one would expect that the rate of return available on a government sponsored project with risk equal to that in the energy sector would correspond to the real after-tax return that applies in that sector. Thus, it might be argued that a reasonable yardstick with which to measure time-dependent cash flows for OCS projects is the real after-tax discount rate that applied in the energy industry.

A recent survey of the 19 largest U.S. oil and gas producers revealed that they used an average real after-tax discount rate of 7 percent. (H. Boyle and G. Schenk, 1985, "Investment Analysis: U.S. Oil and Gas Producers Score High in University Survey," Journal of Petroleum Technology, Vol. 37, No. 4.) Another evaluation of the industry opportunity cost of capital resulted in the measurement of after-tax rates of return on OCS investments in the Gulf of Mexico. (W. Mead et. al., 1980, Studies of Competition and Performance in OCS Oil and Gas Sales, 1954-1975, Final Report, USGS Contract No. 14-08-0001-18678.) The study concluded that companies earned a nominal after-tax rate of about 9 percent, during a period in which inflation was averaging about 2 percent. The nominal rate adjusted for inflation, i.e., the real rate, was therefore about 7 percent.



In light of the foregoing discussion, the analysis in this program document employs a range of discount rates between 6- to 8-percent. Nevertheless, it should be recognized that in considering the social welfare associated with the OCS program, the choice of discount rates is an ethical as well as economic one, and a society's ethics may best be captured through the political process. Any decision to alter the discount rate used to evaluate OCS offerings therefore implies a political decision to modify the pace of leasing both within and among the defined planning areas.

In principle, an economically beneficial path of investment in the search for, as well as the development of, OCS oil and gas deposits could be achieved by taking each step in the investment process for each prospect at the time when, given expected oil prices and costs, the expected value of that step would no longer be increased by a delay in development at a rate that exceeds the discount rate. Although this rule reflects uncertainty about oil and gas deposits and prices and costs, it does not reflect the institutional arrangements and processes by which the Federal Government and private firms bring about OCS investments: the Department of the Interior's leasing program and lease sale procedures, combined with the investment processes that occur in the private sector.

A major advantage of the private investment process is the linking of actual investments to the payoffs as seen by the investors. The actual path of investment in OCS oil and gas results not from the inventory and data compiled by a single organization such as a Government Agency, but from efforts by a diverse set of firms working to identify oil and gas prospects that warrant investment. This diversity helps to reduce the "blindness" that could result from a more monolithic approach, increasing the chances that worthwhile prospects will be identified in a timely manner. It also makes the actual investments voluntary rather than coercive as they would be if made or commanded by a governmental agency. Thus, the Government cannot force investments to go forward; however, it can prevent them from occurring by not making acreage available when firms are ready to invest in it. Similarly, in formulating a leasing program based, in part, on Government estimates, it is reasonable to allow for the fact that firms who are considering acquisition and exploration investments may have significantly different estimates for a given area. The next section elaborates on the possible structures of the leasing program and lease sale procedures and discusses their relationship to the investment decisions made by the petroleum firms engaged in OCS exploration and development.

Generally speaking, private sector investment decisions could be relied upon to give efficiently timed investments in OCS oil and gas deposits if markets were perfectly competitive and free of distortions. In such markets, prices accurately reflect social costs. As commenters on the Draft Proposed Program pointed out, the existence of numerous market imperfections makes it unlikely that private investment decisions will yield the optimum investment path of the idealized model. The important market inperfections identified by these commenters include tax policies, price controls, and externalities such as environmental costs and common information. The existence of market power due to lack of competition in an extractive industry is also a possible market imperfection. It is possible to determine the general effects of such imperfections taken individually. Some, such as taxes, royalties, price controls that depress prices, and market power would tend to slow investments in OCS deposits. Others, such as environmental externalities, tend to yield private investments at times earlier (in periods of increasing resource prices) than is best for society. While the economics literature contains a variety of theoretical analyses of such effects, both individually and in limited combinations, neither the comments nor the literature provide a systematic treatment of all market imperfections. While one commenter recommends a "carefully controlled and designed leasing program . . . to ensure economic efficiency," there are no currently available methods for analyzing the many possible market imperfections and determining how to "control" leasing so as to fully correct for their effects.

Furthermore, given the uncertainty as to the size and location of individual unleased deposits, it does not seem reasonable to design a leasing program that would control the timing of investments on each prospect in light of the effects of market imperfections on private investment decisions. While the Government has the same resource data on unleased OCS oil and gas prospects as do firms, interpretations of those data vary widely. Prior to exploratory drilling, it is not possible to say whether an optimistic or pessimistic assessment of a given prospect is correct. Thus, when a firm is willing to invest in exploration of a prospect while the Government concludes that it is not yet an opportune time for investment, it is not possible for anyone to determine whether the firm's interest reflects market imperfections that would yield premature investment or a possibly correct judgment that the prospect will yield a great enough return to warrant investment. It is thus reasonable to observe that even if the effects of actual market imperfections were well known, a leasing program that attempted to control the timing of investments on the basis solely of the Government's prospect by prospect resource evaluation would be unlikely to yield efficiently timed investments in exploration and development. On the other hand, a policy that would control the timing of investments, correcting for any tendency for premature private investment without relying solely upon the Government's assessment of individual prospects could be a desirable feature of the leasing program.

In areas of proven hydrocarbon occurrence or high industry interest, there may be a tendency for lessees to acquire, explore, and develop prospects sooner than is socially desirable. This situation has greater efficiency implications in areawide sales because more reliance is placed on the private market in making prospect-specific leasing decisions.

An important underlying condition that is associated with the problem of premature leasing is the tendency for exhaustible resource deposits, such as oil and gas, to rise in real price over the long run. This means that the leasing and subsequent development scenario which is best for the Nation may involve a delay in the sale of high cost prospects in a planning area even while investments are proceeding on lower cost prospects. Absent some mechanism to prevent the leasing of prospects, tracts with positive private value could be leased and subsequently developed too soon, partly because of diligence requirements. Ideally, these prospects should be retained in the Government's



inventory until the time when their sale would produce maximum net benefits to the Nation. Moreover, if private after-tax discount rates exceed the government's cost of borrowing, then the present value of cash bonus receipts could be enhanced by delaying the sale of certain types of tracts which industry might otherwise want to acquire. A policy instrument which can be employed to filter for leasing the "right" set of tracts is the minimum bid.

Establishing an appropriate minimum bid based on a standard for the best timing of lease acquisition and subsequent exploration requires an analysis and comparison of the factors that comprise public value (i.e., net economic value (NEV)) and private value (i.e., after-tax net present value (ATNPV)). The factors affecting these two values vary from OCS planning area to planning area and cost regime to cost regime. From the standpoint of economic efficiency, a tract should be leased if its NEV as developed today is greater than if developed in all future periods. Conversely, leasing of tracts should be delayed if the NEV is higher if developed in some future period.

A model has been designed to analyze the appropriate size of the minimum bid under different economic conditions. This model is described in a paper titled: Analysis of Minimum Bid Policies, Branch of Economic Studies, Offshore Resource Evaluation Division, June 7, 1985. It includes an example to demonstrate how the minimum bid can be computed to achieve the objective of appropriate timing for the sale of prospects in a given planning area/water depth.

The model was also employed to evaluate the effects on the smallest field size that should be leased at a given time, and on the size of the minimum bid that should apply at that time, in the presence of changes in existing geologic and economic factors. This analysis was carried out by computing the change in the smallest sized field to be leased, evaluating the ATNPV associated with this new field size under the revised conditions, and comparing the new ATNPV to the original ATNPV.

The analysis found that on a prospect-specific basis, an increase in either the price of oil and gas or the rate of production has the effect of reducing the minimum bid that is appropriate for the best timing of leasing. On the other hand, an increase in the costs of exploration, development, and production leads to an increase in the appropriate level of the minimum bid.* This

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*These results occur because an increase in the economic value of the resources tends to lower the size of the smallest prospect that should be leased at a given time, i.e., some smaller prospects have now matured sufficiently in value to justify current leasing. The revised private value of this smallest leasable prospect is generally lower than the private value of the original smallest prospect that previously was appropriate to lease, so the minimum bid needs to be lowered as well. An important exception occurs in the case of the prospect success rate. As before, an increase in the likelihood of success raises the economic value of the resources and hence lowers the size of the minimum leasable prospect. However, the revised private value of this smaller prospect is generally raised compared to the previously sized smallest leasable prospect, so the minimum bid increases too.

finding is at odds with arguments that conclude that in high-cost areas, the minimum bid should be reduced to encourage bidding. That argument is based on the premise that it is desirable to help stimulate bidding interest in marginal areas. However, based on economic efficiency, encouraging bidding in high-cost areas is not desirable, per se. Other factors being equal, high-cost areas (and high-cost prospects in a given area) should tend to be developed later. This is the pattern developed by the competitive market as evidenced by the development history of both onshore and offshore areas, and is consistent with the sequencing rules discussed earlier for the idealized manager.

In high-risk areas there is usually a high degree of dependence among prospects. This is especially true for unproven areas where the existence of commercial accumulations of hydrocarbons has not been demonstrated. In these cases, the information generated by an exploration program on a given prospect may improve the efficiency of future drilling patterns for much of the surrounding acreage, regardless of whether the specific prospect is hydrocarbon prone or not. However, unless the leaseholder has acquired this informationally related acreage, he will not be able to capture the full value of the benefits that emerge from his exploration program. Also, if companies exhibit risk averse behavior, they will value tracts in frontier areas relatively less than tracts in proven areas. Accordingly, because of these two effects, there will be a tendency for the private market to relatively undervalue and hence lease less acreage in frontier areas vis-a-vis proven areas. To account for these affects, it is appropriate to consider lower minimum bids in high risk areas.

Thus, we see that the desirability of encouraging exploration in high-risk/high-cost areas stems from the information benefits that are imperfectly captured by individual firms. The high basin risk and the attendant information gained from society's perspective in these areas argue for a lower minimum bid, while the high-costs argue for a higher minimum bid. Which one of these countervailing tendencies predominates determines whether or not the minimum bid should be lower or higher.

Unfortunately, interdependence between prospects results in analytical complications that make it difficult to obtain precise results for the minimum bid level in frontier areas. This is primarily the case because of the difficulty in quantifying the geological and economic dependence among prospects, and the information externalities that could emerge. However, since we know that the effect of prospect dependence is to reduce the minimum bid, the minimum bid model can be applied to frontier areas by assuming that prospects are independent, the resulting minimum bid is then interpreted as an upper bound, and no more precise specification based on the timing of leasing criterion may be possible.

The rapid fall in oil prices during early 1986 might suggest that minimum bids should be raised across the board in the OCS planning areas. This inference might follow if no other economic values changed as well, and if the minimum



bid had been set originally on a planning area basis taking into account the timing of exploration and development. In fact, neither of these conditions were satisfied.

As prices were falling, so were future price growth expectations, and current costs of exploration and development. Because these changes drive the timing-related minimum bid down, while current price declines drive it up, the resulting effect is uncertain. Also, the $150 per acre minimum bid was established in frontier areas based on revenue effects on GOM tracts when oil prices were more then twice their current level, and based on fair market value considerations in all areas. However, these issues are moot if there is no leasing interest in selected areas, perhaps in part because the minimum bid is set too high. Maximum flexibility to react to changing economic conditions, such as occurred during 1986, can therefore best be achieved by addressing appropriate minimum bid issues on a sale-specific basis.

Preliminary analysis has been recently conducted to assess the magnitudes of timing-related minimum bids that would be appropriate in the four OCS Regions under current economic conditions. The findings suggest that in virtually every planning area and water depth, the private value of the smallest geologic field size that should be leased now is less than zero. This means that any positive minimum bid selected would be sufficient to encourage economically efficient rates of OCS leasing and exploration.

D. Guidelines for Leasing Program Formulation

The general principles for sequencing the investments in OCS oil and gas and the various possible distributions of resources across the range of net economic values for each planning area can be used to develop a set of economic guidelines for formulating a leasing program. These guidelines can then be modified to incorporate noneconomic considerations as required by section 18 of the OCSLA.

In developing such guidelines, it is necessary to recognize the difference between management of the Federal leasing program and the idealized management of OCS investments discussed above. The leasing program cannot cause investments to be made, as the idealized manager could, when they are judged to be optimal. Instead, the leasing program can make available to private firms certain prospects at an appropriate time. Actual investments in the prospects made available result when such firms find them more attractive than other investment opportunities available to them. Furthermore, the Secretary, in formulating the leasing program, is confronted by substantial uncertainty as to the actual and perceived conditions under which these private firms will make their investment decisions. This places limits on the information relating to resources and economic values which the Secretary has available for consideration. It is not possible to predict with much accuracy or precision what the state of geological knowledge, technology, and price expectations in the period starting in 1987 will be. Thus, the guidelines developed for formulating a leasing program must provide for flexibility in the program so that OCS prospects can be made available in an economically appropriate way under a wide range of future conditions.

The estimates of resources and net economic values in the OCS planning areas provide both the totals for leasable resources and net economic value and the distribution of resources across the range of net economic value per barrel from moderately uneconomical to about $10 per barrel. Section VI discusses these in detail. An idealized OCS manager might ignore the area boundaries and schedule investments by working from the most valuable prospects per barrel down to those just becoming timely for investment. Appropriate economic guidelines for a leasing program can be derived by identifying ways to approximate this sequence through area-by-area lease sales. Thus, based on economic guidelines, lease sales should generally occur earliest in areas with the highest valued prospects per barrel and most frequently in areas with the largest amount of aggregate net economic value. At the other end of the spectrum, areas with no resources having positive economic value, even under the highest price scenarios, should be offered for leasing last, if at all, during the 5-year period.

In developing a guideline to offer the best areas earliest and most frequently, it is reasonable to consider the effects of delays in leasing and investment. Even in the "best" areas (i.e., those having the largest stock of potentially recoverable resources), there are high-cost and low-cost prospects. The low-cost prospects have high net economic value per barrel and would yield less benefit, losing in present value, if leasing and investment were delayed even while prices increased. The high-cost prospects have low net economic value per barrel and could gain more value from delay than they would yield in the present economy. For the better areas, the prospects that would lose from not leasing far outweigh the prospects that would gain from delay. Such a delay in leasing would be a loss to the economy, on balance, in such areas. Moreover, the economic terms of OCS leases along with income tax considerations tend to discourage the acquisition of prospects that would gain from delay. Such prospects tend not to be leasable because royalty and tax payments make them less valuable to a lessee than they are to the nation. This makes it possible to offer areas with many prospects that could gain in benefits if investments were delayed, with some confidence that premature investments will not be made to any substantial extent. When minimum bids are finetuned to enhance intertemporal rates of lease acquisition, the likelihood of premature leasing is further reduced.

For areas that fall in the range between the best areas and the worst areas, development of scheduling guidelines is less obvious. Nevertheless, a reasonable approach begins by determining the conditions under which an area with apparently little resources or economic value should be offered during the 5-year program. One reason to offer a marginal area is that the area may contain more resources than we think it does, perhaps as suggested by industry interest. Another reason is the possibility that a future price increase could very substantially increase the recoverable amount and net economic value of resources in that area. This possibility results from a distribution of resources in which a substantial amount of resources fall in the range just below the "minimum leasable value." Higher prices would shift all deposits to higher net economic value, making more resources beneficial to find and produce. One way to treat such areas is by scheduling frontier exploration sales which could be held if conditions more favorable to leasing



materialize. Estimates of the additional "leasable" resources (i.e., resources having a positive private value) and net economic value resulting from substantially higher prices can help to identify such areas.

Areas with relatively low estimates of leasable resources are worth offering at least once if their net economic value is likely to exceed the external costs plus the administrative costs of holding a lease sale. Furthermore, in many areas, low resource estimates have been based on relatively little geologic and geophysical data. In deciding whether to include low resource areas in the 5-year program, one consideration is the possibility that the firms gathering additional data for their presale evaluations in the area will identify leasable prospects not included in the current MMS estimates. A decision not to offer a marginal area reduces the likelihood of this possibility. In addition, the classification of resources in categories such as high, moderate, or low is subjective and is based on risked mean recoverable resource estimates. Considerable uncertainty and ranges exist in the estimates, therefore they should not be considered exact.

There are a number of areas of moderate resource potential for which the formulation of a leasing program needs to resolve questions of priority and frequency. In general, areas having about the same resource potential should be offered in order of their net economic value. This will tend to allow investments in higher valued resources to occur earlier and will minimize any possibility of premature investments in marginally valued prospects. If areas have about the same aggregate net economic value, but significantly different resource potential, then economic efficiency argues for offering the area with less resources first, because they would have lower costs. Once again, this criterion encourages leasing and hence investment in the highest valued prospects. The set of investments made on the better prospects in that area will have greater expected returns than the set of investments in the area with fewer high value prospects.

A further guideline for establishing priority among similar areas is the extent of previous drilling. The early exploratory wells in a frontier area give strong indications of whether there are hydrocarbons in the area even if they do not yield commercial discoveries. Until such indications are confirmed, the area must be regarded as having a relatively low probability of hydrocarbon presence. This low probability results in low estimates of risked leasable resources and expected net economic value even if the volumes of identified prospects are substantial. By comparison, an area with a much higher probability of hydrocarbons because of previous drilling could have similar risked resources and net economic value from fewer prospects. As a result, drilling in the unexplored area can yield information that could more significantly change the estimates on which subsequent investments will be based. Thus, it is generally preferable to offer unexplored areas first, when risked resources and economic values are similar.

## VI. OCS Resources and Net Economic Value Estimates: Considerations for Leasing and Program Formulation

### A. Introduction

The analysis of resource potential and net economic value in each OCS planning area was designed to help the Secretary consider the potential for discovery of oil and gas in each of the areas and the contribution such discoveries can make toward meeting the Nation's economic and energy needs. It was also designed to facilitate the analysis of the external costs that might result from the exploration, development, and production of the resources in each area. This section provides a detailed description of the investment process and the way in which the economic benefits were estimated for the potential oil and gas discoveries which they may yield.

Two fundamental problems are confronted in estimating the oil and gas resources and the economic value for OCS planning areas. The first is the inherent uncertainty about the results of each step in the investment process. Because little is known about the location and size of oil and gas deposits until actual investments in exploration have been made, the results can vary from highly negative to highly positive with regard to the initiation of each subsequent step in the development process. Resource and economic value estimates need to reflect these chance outcomes.

The second problem encountered is the incorporation of investment decisions and the possible economic conditions under which they will be made into the economic value estimates. Hydrocarbon-bearing areas contain more oil and gas than will be recovered under the economic conditions that prevail in the period relevant to formulation of the leasing program. The resource and economic value estimates considered by the Secretary need to show how the potential for discovery of oil and gas and the economic benefits realized from their production are affected by economic conditions.

This section discusses how the two problems mentioned above are dealt with in estimating oil and gas resources and net economic value for OCS planning areas. Next, a series of measures of resources and economic values are presented for each planning area. The section concludes with a discussion of the relationship between the data presented and generation of the appropriate parameters of a leasing schedule.

### B. Stages in OCS Investment Decisions

The series of investment decisions leading to the production of oil and gas that can meet national energy and economic needs is essentially structured according to the operational steps required to bring a lease to production. The following discussion highlights the types of operational activities occurring during each step in the process:



#### 1. Prelease Evaluation

Firms invest in geological and geophysical (seismic) data and evaluation to identify and assess individual prospects for discovery of oil and gas. Undiscovered resource estimates are made by identifying areas of resource potential on the basis of broad geologic knowledge and theory. Until a well has been drilled, investigators derive all their knowledge of subsurface geology indirectly from geologic and geophysical data collected at the surface. Using available data as a basis for further investigations, petroleum geologists then conduct a variety of geologic assessments of the region. The geologists' data base may include physical confirmation of the presence of resources by actual drilling in an area that has been previously leased. Under prelease permits, geophysical surveys and shallow coring and deep stratigraphic test drilling may be done. This is generally completed before a lease sale. The knowledge gained from these geological and geophysical analyses are used to highlight prospective areas and to determine which tracts to bid on and how much to bid at a lease sale.

#### 2. Leasing

Firms invest in the acquisition of oil and gas rights through competitive bidding. The primary terms of the lease involve financial considerations in the form of future payments to the Government, and stipulations requiring that specific milestones and tasks be met by the lessee in order to retain the rights to the lease.

#### 3. Exploratory Drilling

Following a lease sale, the initial phase of offshore oil and gas operations, known as exploratory drilling, begins. Firms invest in drilling of prospects on tracts they have leased to determine the presence and extent of oil and gas; most prospects contain no oil and gas.

Exploration is generally completed within 5 years of the date of issuance of a lease; 5 years is the length of the primary term of leases set by law unless certain specific conditions exist. Once a tract has been leased, geological, cultural, and biological surveys are conducted to develop a comprehensive exploration plan. The operator cannot begin exploratory drilling until an exploration plan has been approved for the lease and an application for permit to drill (APD) a well has been submitted and approved. Obtaining these approvals also entails obtaining permits or approvals from other agencies, such as State Coastal Zone Management consistency certification and EPA NPDES permits. For leases issued with an initial period of 5 years, an exploration plan or a statement of exploration intentions must be submitted by the end of the fourth lease year. The time period for submittal on leases with longer primary terms (such as 8- or 10-year leases) must be specified at the time of leasing. The exploration plan and APD provide a concise description of the proposed offshore operations including specific information on the location and depth of wells. Revisions must be submitted and approved for any significant changes.

When exploration begins, operators select one of several types of drilling rigs to match water depth, drilling depth, and bottom conditions. The offshore exploration activity is supported by onshore bases from which supplies are transported to the drilling rig. Apart from these supply bases, little onshore development generally takes place during the exploration phase.

4. Delineation and Development

The delineation and development phase encompasses the activities necessary to bring a discovered field to the point of commercial production. This is a period of intense activity. Firms invest in the installation of production platforms, wells, pipelines, and equipment used to recover oil and gas. When significant quantities of hydrocarbons are discovered, delineation wells are drilled to determine the field's configurations and capacity.

Most of the critical decisions concerning the location and construction of onshore and offshore facilities are made during the development phase. An OCS operator prepares for the production phase through development activities which include extensive planning, submission, and approval of plans of development and production (POD/P), installation of platforms and pipelines, and development drilling. The onshore facilities required to support development activities may include permanent service bases, repair and maintenance yards, storage and treatment plants, and marine terminals. In mature areas such as the Central and Western Gulf of Mexico planning areas, in comparison to frontier areas, impacts are lessened because this infrastructure has already been adequately developed to handle most of the demand. Here, economies of scale can be realized as costs are lower because only incremental expansion of offshore production and pipeline facilities, onshore support and processing facilities, or maintenance of existing capacity due to excess created by reduced activity in older fields are necessary. Early developers in frontier areas must at least initially bear all such costs.

Completion is the term used to encompass the various activities necessary to convert a well into a producer of oil and/or gas. It may involve setting and cementing casing; perforating the casing to permit oil and gas to flow into the wellhole; fracturing; acidizing; consolidating sand; setting tubing; and installing downhole safety devices. Deepwater wells (800 to 1,000 feet of water), drilled and produced from sophisticated platforms, are becoming more common. Subsea completions for even deeper water are available but are being used more worldwide than offshore United States. These are wells in which the major assembly of piping, valves, and related equipment used to produce oil and gas are located at or near the sea bottom. The wellhead is placed on the sea floor rather than on platforms, and the produced liquids or gases are transferred from the wellhead either to the nearby platform or directly to a shore facility.



5. Production

In the production phase, oil and gas are produced from offshore wells. Hydrocarbons are normally transported to shore in the pipelines laid during the development phase; otherwise, they are transported by tankers or barges. Production has the longest duration of all phases of offshore operations related to a specific prospect. It may last for 20 to 30 years. Characteristically, employment offshore drops sharply from that of the development stage as production becomes routine. In addition, some platforms are automated and require only daily inspections and regular maintenance. The process of bringing new fields into full production requires additional drilling and labor. Until each new field is defined, exploration and development drilling in the form of delineation will continue. When production declines, wells are periodically worked over to boost output.

C. Resource Recovery and Economic Conditions

In formulating a leasing program, it is reasonable for the Secretary to consider how much hydrocarbons in each OCS planning area will be found and recovered. Such estimates need to reflect the economic behavior of the many firms making the investment decisions by which resources are expected to be leased, explored, discovered, developed into proven reserves, and produced. Given estimated prices and costs, these economic decisions may result in leaving some of the oil and gas that is actually in place unrecovered for a variety of reasons, including:

- those in geological features that are not "visible" in the geological and geophysical data on which bidding and exploratory drilling are based.
- those in prospects not worth bidding upon.
- those in prospects that get leased but are judged not to be worth drilling.
- those in drilled prospects that are missed.
- oil and gas deposits that are found by exploratory drilling but which are not worth developing.
- oil and gas in place in discoveries that are developed but which are not worth recovering.

The bidding, exploration, development, and recovery decisions that yield these results depend, to an important extent, on economic conditions. Since prices and costs change over time, oil and gas that would not be found and produced during one period in time may later become economic, particularly if the ratio of prices to costs increase. Most resource estimating methods include general assumptions about the portion of oil or gas in a discovered deposit that is economically recoverable, primarily relying upon past experience to set the percentage recovery. Similarly, most methods reflect the condition that deposits below a certain size have been uneconomic.

Unfortunately, most resource estimates do not reflect the increases in the percentage recovery that may result at higher oil prices. Similarly, most resource estimates have not been precise in the use of the concept of minimum economic field size. The resource estimates developed for the formulation of the 5-year leasing program, however, emerged from methods that are able to show the effect of changing economic conditions on the resources that are economic at various steps in the investment process for those prospects that have been identified as containing at least some economically recoverable resources at current and expected future prices.

Given the costs of drilling operations, platform construction and installation, transportation in a particular area, and expectations about future prices, the primary determinant of whether or not the oil and gas in a particular unexplored prospect or discovered deposit is recoverable is the amount of oil and gas it contains. Because some investments are not easily divisible (for example, it's not possible to drill half a well), the minimum lump sum investment can overwhelm the production revenues from a small deposit. Thus, for each level of costs, there is a minimum economic prospect or field size that is equal to the next lump sum of investment. There is a minimum size that is worth leasing, given the geologic risk, the minimum bid, and other economic terms of the lease. There is similarly a minimum size that is worth the initial lump sum of investment in development given that the deposit has already been found. For given price expectations and geologic risk, the higher the costs, the larger such minimums will be, and the greater the size and number of uneconomic prospects and deposits in an area.

The unleased, undiscovered oil and gas existing in an OCS planning area at a given point in time is distributed among a population of prospects of various sizes and locations. The conditional resource sizes of these prospects and their geologic risks are dependent upon the information available to make such estimates. As such, it is not surprising to find little data on prospects that are not economical to produce because they are too small and/or too costly under current and expected future economic conditions. Thus, while sophisticated models are capable of evaluating the sensitivity of production for the identified fields for myriad assumptions regarding economic parameters, it must be recognized that the set of identified prospects is, by necessity, "limited" to those having at least some chance (i.e., 1 in 5,000) of being economical to produce under the base case economic scenario.

The uncertainties associated with the overall presence of oil and gas in an area and about the key parameters affecting individual prospects are incorporated into resource estimating methods. Estimates that assume the existence of oil and gas in an area are called conditional resource estimates. Conditional resource estimates are good indicators of the oil and gas production that could result from successful investments in various OCS areas. They reflect the recoverable resources that could be contained by the volumes of oil and gas bearing rock estimated to be present in the area. They do not reflect the likelihood that oil and gas is, in fact, trapped in those volumes.



Conditional resource estimates are most useful in assessing the environmental impacts that might result from oil and gas exploration, development, and production activities.

Conditional resource estimates, however, substantially overstate the results of exploration in the OCS as a whole, just as assuming every lottery ticket was a winner would overstate the total prize money of a lottery. The potential for oil and gas discovery in an area depends upon the chances of finding oil and gas, as well as the volumes of reservoir rock that can contain oil and gas. For areas with no previous discoveries, the probabilities are substantially less than 100 percent. Thus, it is appropriate to consider estimates that reflect the probability that oil and gas are present in the area. Risked resource estimates (which take into account the probability of hydrocarbon occurrence) reflect those probabilities. Expected net economic value estimates are based on risked resource estimates.

## D. Resource Estimates and Economic Values

Traditional economic analysis, usually in the form of cost-benefit studies, focuses on the sum of consumer and producer surplus as the principal criterion of a program's efficiency. Consumer surplus measures the difference between the amount that users or purchasers of a good or service would be willing to pay and the amount they are required to pay at the market-clearing equilibrium price. Producer surplus typically measures the difference between the revenue received by the seller (producer) of the good or service and the opportunity cost of producing it.

Because the OCS market represents only a small portion of the world's petroleum market, and because this market is highly influenced by the production and reserves of OPEC countries, it is reasonable to assume that alternative OCS policies and resulting production rates will have a negligible effect on the world price of oil. Because of this, we have a situation in which incremental OCS production simply substitutes for the highest cost alternative source of petroleum currently being sold in the U.S. market, i.e., imported oil.

As long as OCS production has little or no effect on the market price of oil, it also does not directly benefit the ultimate consumers of petroleum. Thus, the analysis of benefits and costs can focus on benefits accruing from the production of the resource without addressing changes in consumer surplus. Measurement of benefits derived from oil and gas price changes induced by OCS production was discussed earlier in the section dealing with import premia.

In the case of the OCS, where the assets represented by potential oil and gas deposits are owned by the U.S. Government and subsequently leased to private industry for ultimate extraction, producer surplus represents the difference between the market value of expected production and the real resource cost of exploring, developing, producing, and transporting the expected production to market. This economic rent, or net economic value, will be distributed between the lessor (U.S. Government) and the lessees (private firms), depending upon the relative amount of transfer payments which the Government collects in the form of cash bonuses, rentals, royalties, windfall profits taxes, and corporate income taxes. The remainder of the net economic value is retained by private industry in the form of economic (as opposed to accounting) profits.

Assuming the absence of capital constraints and employing a reasonable opportunity cost of capital for the discount rate, the resulting measure of net economic value will simultaneously represent the improvement in national income to the country from a specified OCS investment alternative, as well as the total of the resulting transfer payments and corporate profits. Even if investment opportunities are constrained by capital shortages, establishment of an appropriate (marginal) opportunity cost of capital will result in a realistic and, insofar as possible, accurate estimate of the incremental improvement in net economic value and the related transfer payments.

While the vast majority of benefits generated by an OCS schedule can be measured by net economic value, as discussed previously, there are other less important but not insignificant benefits. First is the potential savings on the size of the Strategic Petroleum Reserve as OCS production replaces imports. Even if no change in the Strategic Petroleum Reserve is forthcoming, the given size of the inventory will afford a higher level of protection as imports decline.

Other benefits of OCS production include incentives for OPEC to lower prices, increased national security, continued employment for direct and supplier related workers, improvements in our balance of trade, and reductions in the budget deficit. While no attempt is made to quantify these additional benefits, their presence and potential magnitude suggest that the net economic value estimates, even as large as they are, represent a rather conservative measure of the benefits of the OCS program.

The MMS has estimated the undiscovered economically recoverable oil and gas resources expected to be unleased as of mid-1987 (see Table 6) and net economic value in the various OCS planning areas. These estimates of necessity reflect the state of geological and geophysical knowledge and expectations of the relevant future economic conditions at the time the estimates were made (see section VII). They were based on a mid-1987 starting point for the next 5-year leasing program. The resulting estimates of unleased, undiscovered, economically recoverable oil and gas resources reflect geological and geophysical knowledge as of the first quarter of 1985 and contemporary projections of economic conditions for the period 1987 through 2016. These estimates incorporate the appropriate exploration, development, and production timetables for each planning area and field size. They also assume, for comparison purposes, that all resources which are privately worth acquiring are leased in mid-1987 (assuming no capital constraints).

Given the complexities and effects of changing economic conditions and geological uncertainty on oil and gas resource estimates, it is useful to examine a number of different types of resource estimates in considering the oil and gas potential of OCS areas. One set of estimates mentioned earlier



is represented by the distribution of conditional economically recoverable oil and gas resources, which represents the potential amounts of oil and gas that could be produced in a particular area assuming that the area contains petroleum and that lease acquisition and exploration costs have been expended. This distribution gives a good indication of the probability of finding and recovering specific amounts of oil and gas under expected economic conditions assuming that exploration has confirmed its presence. The means or average values of the conditional distribution of economically recoverable oil and gas resources also have been estimated for each OCS planning area. The relevant parameters of the conditional distributions of economically recoverable resources are shown in Table 5.

In those areas in which commercial quantities of oil and/or gas have been discovered, the absolute range of conditional resource outcomes is wide; however, Table 5 shows that in virtually all areas the relative size of the range is similar.

For example, in the Central Gulf of Mexico, the marginal probability of finding hydrocarbons is, of course, equal to one. Hence, the risked and conditional distributions of economically recoverable resources are equivalent. For this planning area, the potential size of (unleased) economically recoverable resources ranges from about one-third of the risked mean value at the lower 5 percent end of the distribution, to about 80 percent above the risked mean value at the upper 5 percent of the distribution. (These figures were approximated by adding the available oil and gas figures at each confidence level. This approach yields an exact solution only if the oil and gas are perfectly correlated.)

The relative range of economically recoverable resource estimates around the conditional mean value for frontier areas is similar to that found for the Central Gulf of Mexico, as well as the other proven areas. (The two exceptions are the Beaufort Sea and Norton Basin, which have ranges about two to four times that of the other areas.) For example, in the Navarin Basin, the lower end of the conditional resource distribution is about one-half the conditional mean, while the upper (5 percent) end is about one-half more then the conditional mean. Of course, since the marginal probability of success is 0.27, the risked mean value is about one-fourth of the conditional mean and one-half of the lower 5-percent tail of the conditional distribution. These relations suggest the broad range of economically recoverable resources that could result for any given set of economic assumptions.

While it is useful to assess the environmental consequences of leasing in specific areas using conditional resource estimates, it is necessary to consider the "risked" measure of resource amounts in conducting the economic analysis for the 5-year schedule. This is the case because conditional measures generally are not comparable in a meaningful sense among planning areas; the risked measures are comparable since they incorporate the appropriate likelihood of hydrocarbon occurrence.

TABLE 5

Estimates of Undiscovered Economically Recoverable Oil and Gas Resources as of March 1985
Alaska Region

| Planning Area | Conditional Oil--BBO 95% Case | 5% Case | Mean Case | Conditional Gas--TCF 95% Case | 5% Case | Mean Case | $MP_{HC}$ | Risked Mean Oil (BBO) | Risked Mean Gas (TCF) | Risked BOE (BBOE) |
|---|---|---|---|---|---|---|---|---|---|---|
| Cook Inlet | | | | | | | | | | |
| Leased and Unleased | 0.06 | 0.46 | 0.21 | 0.08 | 0.76 | 0.35 | 0.03 | 0.01 | 0.01 | 0.01 |
| Unleased | 0.03 | 0.40 | 0.18 | 0.04 | 0.69 | 0.32 | 0.03 | 0.01 | 0.01 | 0.01 |
| Leased | 0.04 | 0.12 | 0.06 | 0.04 | 0.15 | 0.09 | 0.01 | neg.* | neg.* | neg.* |
| Gulf of Alaska | | | | | | | | | | |
| Leased and Unleased | 0.14 | 1.00 | 0.54 | 1.80 | 18.46 | 8.34 | 0.08 | 0.04 | 0.66 | 0.16 |
| Unleased | 0.12 | 0.86 | 0.49 | 1.60 | 18.26 | 8.00 | 0.08 | 0.04 | 0.64 | 0.15 |
| Leased | 0.03 | 0.24 | 0.10 | 0.12 | 0.88 | 0.40 | 0.05 | 0.01 | 0.02 | 0.01 |
| Kodiak | | | | | | | | | | |
| Leased and Unleased | 0.04 | 0.26 | 0.15 | 0.58 | 7.13 | 2.92 | 0.05 | 0.01 | 0.13 | 0.03 |
| Unleased | 0.04 | 0.26 | 0.15 | 0.58 | 7.13 | 2.92 | 0.05 | 0.01 | 0.13 | 0.03 |
| Leased | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Shumagin | | | | | | | | | | |
| Leased and Unleased | 0.05 | 0.09 | 0.05 | 0.49 | 2.65 | 1.42 | 0.03 | neg.* | 0.04 | 0.01 |
| Unleased | 0.05 | 0.09 | 0.05 | 0.49 | 2.65 | 1.42 | 0.03 | neg.* | 0.04 | 0.01 |
| Leased | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

* Negligible



TABLE 5

Estimates of Undiscovered Economically Recoverable Oil and Gas Resources as of March 1985
Alaska Region

| Planning Area | Conditional Oil--BBO 95% Case | 5% Case | Mean Case | Conditional Gas--TCF 95% Case | 5% Case | Mean Case | $MP_{HC}$ | Risked Mean Oil (BBO) | Risked Mean Gas (TCF) | Risked BOE (BBOE) |
|---|---|---|---|---|---|---|---|---|---|---|
| St. George Basin | | | | | | | | | | |
| Leased and Unleased | 0.82 | 2.56 | 1.69 | 7.33 | 28.18 | 15.76 | 0.22 | 0.37 | 3.47 | 0.99 |
| Unleased | 0.37 | 1.98 | 1.12 | 3.42 | 18.04 | 9.24 | 0.22 | 0.25 | 2.03 | 0.61 |
| Leased | 0.24 | 0.91 | 0.57 | 2.40 | 12.04 | 6.60 | 0.22 | 0.13 | 1.45 | 0.38 |
| North Aleutian | | | | | | | | | | |
| Leased and Unleased | 0.08 | 0.76 | 0.36 | 0.56 | 5.25 | 2.62 | 0.20 | 0.08 | 0.54 | 0.17 |
| Unleased | 0.08 | 0.76 | 0.36 | 0.56 | 5.25 | 2.62 | 0.20 | 0.08 | 0.54 | 0.17 |
| Leased | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Navarin Basin | | | | | | | | | | |
| Leased and Unleased | 3.05 | 6.88 | 4.80 | 3.65 | 8.51 | 5.84 | 0.27 | 1.30 | 1.58 | 1.58 |
| Unleased | 1.81 | 5.09 | 3.28 | 2.34 | 6.75 | 4.26 | 0.27 | 0.89 | 1.15 | 1.09 |
| Leased | 0.82 | 2.30 | 1.51 | 0.89 | 2.26 | 1.59 | 0.27 | 0.41 | 0.43 | 0.48 |
| Norton Basin | | | | | | | | | | |
| Leased and Unleased | 0.09 | 1.64 | 0.64 | 0.51 | 6.31 | 2.94 | 0.15 | 0.09 | 0.43 | 0.17 |
| Unleased | 0.05 | 1.02 | 0.28 | 0.31 | 4.26 | 1.55 | 0.12 | 0.03 | 0.18 | 0.07 |
| Leased | 0.06 | 1.16 | 0.47 | 0.42 | 3.62 | 1.81 | 0.13 | 0.06 | 0.24 | 0.11 |

TABLE 5

Estimates of Undiscovered Economically Recoverable Oil and Gas Resources as of March 1985
Alaska Region

| Planning Area | Conditional Oil--BBO 95% Case | 5% Case | Mean Case | Conditional Gas--TCF 95% Case | 5% Case | Mean Case | $MP_{HC}$ | Risked Mean Oil (BBO) | Risked Mean Gas (TCF) | Risked BOE (BBOE) |
|---|---|---|---|---|---|---|---|---|---|---|
| Hope Basin | | | | | | | | | | |
| Leased and Unleased | 0.13 | 0.40 | 0.17 | 0.53 | 4.12 | 1.81 | 0.02 | neg.* | 0.04 | 0.01 |
| Unleased | 0.13 | 0.40 | 0.17 | 0.53 | 4.12 | 1.81 | 0.02 | neg.* | 0.04 | 0.01 |
| Leased | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Chukchi Sea** | | | | | | | | | | |
| Leased and Unleased | 0.96 | 4.88 | 2.68 | 5.06 | 27.71 | 15.10 | 0.20 | 0.54 | 0 | 0.54 |
| Unleased | 0.96 | 4.88 | 2.68 | 5.06 | 27.71 | 15.10 | 0.20 | 0.54 | 0 | 0.54 |
| Leased | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Beaufort Sea** | | | | | | | | | | |
| Leased and Unleased | 0.23 | 3.22 | 1.28 | 1.01 | 13.13 | 5.62 | 0.70 | 0.89 | 0 | 0.89 |
| Unleased | 0.11 | 1.66 | 0.65 | 0.52 | 6.39 | 2.98 | 0.69 | 0.45 | 0 | 0.45 |
| Leased | 0.03 | 2.38 | 0.60 | 0.22 | 8.95 | 3.18 | 0.64 | 0.39 | 0 | 0.39 |
| Total Alaska Region Leased and Unleased | | | | | | | | 3.33 | 6.90 | |

* Negligible

** In the Chukchi Sea and Beaufort Sea OCS Planning Areas, water depth of 200 feet is considered to be the limit of current arctic production and development technology. Based on current cost/price relationships and foreseeable technological advances, the conditional mean gas resources estimated to exist in the Beaufort Sea and Chukchi Sea Planning Areas are assumed to be noneconomic at this time.



TABLE 5

Estimates of Undiscovered Economically Recoverable Oil and Gas Resources as of March 1985
Atlantic Region

| Planning Area | Conditional Oil--BBO 95% Case | 5% Case | Mean Case | Conditional Gas--TCF 95% Case | 5% Case | Mean Case | $MP_{HC}$ | Risked Mean Oil (BBO) | Risked Mean Gas (TCF) | Risked BOE (BBOE) |
|---|---|---|---|---|---|---|---|---|---|---|
| North Atlantic | | | | | | | | | | |
| Leased and Unleased | 0.10 | 0.43 | 0.26 | 1.98 | 9.03 | 5.06 | 0.30 | 0.08 | 1.52 | 0.35 |
| Unleased | 0.10 | 0.43 | 0.26 | 1.98 | 9.03 | 5.06 | 0.30 | 0.08 | 1.52 | 0.35 |
| Leased | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mid-Atlantic | | | | | | | | | | |
| Leased and Unleased | 0.10 | 0.77 | 0.36 | 1.84 | 11.68 | 5.98 | 1.00 | 0.36 | 5.98 | 1.42 |
| Unleased | 0.07 | 0.51 | 0.24 | 1.39 | 8.18 | 4.21 | 1.00 | 0.24 | 4.21 | 0.99 |
| Leased | 0.01 | 0.40 | 0.14 | 0.20 | 5.94 | 2.12 | 0.79 | 0.11 | 1.66 | 0.41 |
| South Atlantic | | | | | | | | | | |
| Leased and Unleased | 0.39 | 1.56 | 0.92 | 7.17 | 29.11 | 16.95 | 0.25 | 0.23 | 4.24 | 0.98 |
| Unleased | 0.36 | 1.51 | 0.87 | 6.62 | 28.18 | 16.22 | 0.25 | 0.22 | 4.06 | 0.94 |
| Leased | 0.01 | 0.09 | 0.04 | 0.13 | 1.41 | 0.62 | 0.25 | 0.01 | 0.16 | 0.04 |
| Florida Straits | | | | | | | | | | |
| Leased and Unleased | neg.* | 0.41 | 0.14 | 0.08 | 4.86 | 1.66 | 0.10 | 0.01 | 0.17 | 0.04 |
| Unleased | neg.* | 0.41 | 0.14 | 0.08 | 4.86 | 1.66 | 0.10 | 0.01 | 0.17 | 0.04 |
| Leased | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Atlantic Region Leased and Unleased | | | | | | | | 0.66 | 11.65 | |

* Negligible

TABLE 5

Estimates of Undiscovered Economically Recoverable Oil and Gas Resources as of March 1985
Gulf of Mexico Region

| Planning Area | Conditional Oil--BBO 95% Case | 5% Case | Mean Case | Conditional Gas--TCF 95% Case | 5% Case | Mean Case | $MP_{HC}$ | Risked Mean Oil (BBO) | Risked Mean Gas (TCF) | Risked BOE (BBOE) |
|---|---|---|---|---|---|---|---|---|---|---|
| **Eastern Gulf of Mexico** | | | | | | | | | | |
| Leased and Unleased | 0.06 | 1.56 | 0.41 | 0.11 | 9.50 | 2.19 | 1.00 | 0.41 | 2.19 | 0.80 |
| Unleased | 0.03 | 1.48 | 0.36 | 0.04 | 8.88 | 1.63 | 0.99 | 0.35 | 1.62 | 0.64 |
| Leased | neg.* | 0.16 | 0.06 | neg.* | 1.49 | 0.43 | 0.97 | 0.06 | 0.42 | 0.13 |
| **Central Gulf of Mexico** | | | | | | | | | | |
| Leased and Unleased | 1.40 | 6.70 | 3.75 | 12.45 | 64.45 | 30.69 | 1.00 | 3.72 | 30.69 | 9.18 |
| Unleased | 0.95 | 4.97 | 2.66 | 7.57 | 36.53 | 20.64 | 1.00 | 2.66 | 20.64 | 6.33 |
| Leased | 0.27 | 1.67 | 0.82 | 3.58 | 26.30 | 7.54 | 1.00 | 0.82 | 7.54 | 2.16 |
| **Western Gulf of Mexico** | | | | | | | | | | |
| Leased and Unleased | 0.61 | 3.64 | 1.90 | 10.06 | 47.92 | 26.76 | 1.00 | 1.90 | 26.76 | 6.66 |
| Unleased | 0.45 | 3.31 | 1.69 | 7.23 | 41.05 | 22.61 | 1.00 | 1.69 | 22.61 | 5.71 |
| Leased | 0.07 | 0.46 | 0.22 | 1.72 | 8.12 | 4.34 | 1.00 | 0.22 | 4.34 | 0.99 |
| **Total Gulf of Mexico Region** | | | | | | | | | | |
| Leased and Unleased | | | | | | | | 6.03 | 59.64 | |

* Negligible



TABLE 5

Estimates of Undiscovered Economically Recoverable Oil and Gas Resources as of March 1985
Pacific Region

| Planning Area | Conditional Oil--BBO 95% Case | 5% Case | Mean Case | Conditional Gas--TCF 95% Case | 5% Case | Mean Case | $MP_{HC}$ | Risked Mean Oil (BBO) | Risked Mean Gas (TCF) | Risked BOE (BBOE) |
|---|---|---|---|---|---|---|---|---|---|---|
| **Southern California** | | | | | | | | | | |
| Leased and Unleased | 0.84 | 2.41 | 1.54 | 1.37 | 3.62 | 2.42 | 1.00 | 1.54 | 2.42 | 1.97 |
| Unleased | 0.61 | 2.08 | 1.26 | 0.97 | 2.98 | 1.93 | 1.00 | 1.26 | 1.93 | 1.60 |
| Leased | 0.09 | 0.56 | 0.27 | 0.19 | 0.83 | 0.52 | 1.00 | 0.27 | 0.52 | 0.36 |
| **Central California** | | | | | | | | | | |
| Leased and Unleased | 0.18 | 1.01 | 0.56 | 0.29 | 1.38 | 0.79 | 0.65 | 0.36 | 0.51 | 0.46 |
| Unleased | 0.18 | 1.01 | 0.56 | 0.29 | 1.38 | 0.79 | 0.65 | 0.36 | 0.51 | 0.46 |
| Leased | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Northern California** | | | | | | | | | | |
| Leased and Unleased | 0.15 | 0.76 | 0.42 | 1.17 | 2.48 | 1.86 | 0.60 | 0.25 | 1.12 | 0.45 |
| Unleased | 0.15 | 0.76 | 0.42 | 1.17 | 2.48 | 1.86 | 0.60 | 0.25 | 1.12 | 0.45 |
| Leased | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Oregon/Washington** | | | | | | | | | | |
| Leased and Unleased | 0.04 | 0.54 | 0.18 | 2.20 | 3.62 | 3.26 | 0.20 | 0.04 | 0.65 | 0.15 |
| Unleased | 0.04 | 0.54 | 0.18 | 2.20 | 3.62 | 3.26 | 0.20 | 0.04 | 0.65 | 0.15 |
| Leased | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Pacific Region** | | | | | | | | | | |
| Leased and Unleased | | | | | | | | 2.19 | 4.70 | |

To obtain the risked levels of economically developable oil and gas resources, a planning area's mean conditional resource levels are multiplied by the chance that geological conditions exist such that the planning area is considered to contain a commercial accumulation of hydrocarbons. This likelihood is defined by the term "marginal probability"; its value for each planning area is shown in Tables 5 and 6. The resulting estimates of risked economically developable oil and gas resources are also provided in Tables 5 and 6. A single measure, called barrels of oil equivalent (BOE), is obtained by converting the risked gas to the Btu equivalent of oil and then simply adding it to the risked oil figure. One barrel of oil contains the heating content of about 5.62 thousand standard cubic feet of gas. The units in Tables 5 and 6 are billions of barrels of oil and trillions of cubic feet of gas. Hence, to obtain (risked) equivalent barrels of oil, we divide the gas amount by 5.62 and add it to the oil amount.

Although these average values are the statistically "best" measures to use in the economic analysis, it is important to reemphasize the inherent uncertainity and variability of the resource estimates. The risked resource size associated with each planning area represents the average results that would emerge if the exploration and development scenario were repeated 5,000 times in an area. Of course, in practice, only one sequence of exploration and development activities will occur in each planning area. Hence, the actual results could differ substantially from the expected results.

The greatest dispersion, or possible range of outcomes around the average results, is associated with frontier areas where the commercial viability of oil and/or gas production has not been established. In these cases, regardless of the average values, an outcome of zero production is not an unrealistic lower-bound estimate. The likelihood of no production is simply one minus the marginal probability of hydrocarbon success, $MP_{hc}$. For the North and South Atlantic, and all areas of Alaska excluding the Beaufort Sea, the likelihood of zero production is estimated to be at least 0.70.

The March 1985 resource estimates from Table 5 for the various OCS planning areas were adjusted to reflect unleased resources available as of mid-1987. This adjustment was made by estimating the quantity of resources that would be leased in each OCS planning area between March 1985 and mid-1987 and subtracting that amount from the March 1985 unleased resources. The unleased resources as of mid-1987 in each OCS planning area represent the difference between the two numbers. The removal of tracts to be leased is assumed to have no effect on the marginal probability for the remaining unleased tracts. The unleased resources as of mid-1987 are used beginning with Table 6.

Note that Table 6 was further adjusted by adding resources that were expected to be leased, but were not because of sale cancellations, as well as subtracting resources affected by recent Secretarial deletion options.

In many of the planning areas studied, hundreds of geologic prospects were identified having some likelihood of containing hydrocarbon resources in amounts greater than that size necessary to encourage development, given that the fields have been discovered. However, prior to exploration, many of these developable fields have negative private values adjusted for risk and net of exploration costs.



Thus, in considering the potential for oil and gas discovery, it is appropriate to recognize that discovery results from investments in lease acquisition and exploratory drilling. Under a given set of economic conditions and geologic risk, some prospects are not worth acquiring and drilling even though they would be profitable to develop if such investments had already been made and the deposit found.

Lease acquisition and exploration investments are based upon both the size and the probability of the economic payoffs that can result. The MMS has estimated the risked economically developable oil and gas resources and their net economic value for the prospects that are profitable for private energy companies to invest in lease acquisition and exploration, i.e., they are leasable. These estimates are expressed in "risked" or "expected value" form, which means that the resource amounts and economic values reflect the appropriate probabilities of the different states of (geological) nature that could result. Table 6A shows the range of estimates of risked resources and expected net economic value from the set of prospects in each OCS area privately worth leasing and exploring.

The economic assumptions for these analyses, as described in section VII, include free on board (FOB) port of export oil prices ranging from $14 to $29 per barrel in July 1984, a 1 percent real oil and gas annual price increase, an 8 percent discount rate, and a 5 percent inflation rate. A July 1984 price is used as the initial reference price because this analysis began at that time; appropriate adjustments due to inflation and real price growth as just indicated have been made to bring the price to the 1987 level. (The landed Btu-equivalent oil prices are used as the basis for gas prices.) Applying these assumptions and employing the techniques described in section VII, the net economic values as of mid-1987 have been calculated and are contained in Table 6A. The four lowest ranked planning areas in Table 6 are deleted from Table 6A and subsequent tables in this appendix because their current economically recoverable resource magnitudes are estimated to be negligible.

The aggregate magnitude and value of leasable resources do not, however, provide a complete picture of the resource and economic potential of an area. This is so because a large portion of total net economic value may result from a moderate amount of high-valued resources or a very substantial amount of lower valued resources. Table 7 shows how the resource potential is distributed by net economic value in each area.

Table 8 evaluates the effects of alternative July 1984 starting price assumptions ($14, $19, $24, and $29 in 1984 dollars) on the amounts of developable resources that are on leasable prospects for each of the planning areas. Table 8 shows that some areas, such as the Chukchi Sea, Gulf of Alaska, St. George Basin, North Aleutian Basin, Norton Basin, and the North Atlantic have much better leasing possibilities at the $29 price scenario.

14-29

An important consideration in deciding when to offer the potential resources in a given planning area for lease, or how to order the offering of all planning areas, is the cost of delaying the sale (and hence, presumably, delaying exploration and development) of leasable prospects. In cases where the net economic value per barrel is expected to increase in present worth from future rather than current offerings, such planning areas generally should be timed for sale later (if at all) in the schedule.

Measures of the aggregate average cost of delay for all currently (mid-1987) leasable prospects in each planning area for a range of prices are presented in Table 9. These measures were developed under both 1- and 2-percent real oil price increase scenarios over a one-year delay interval. A delay in leasing is assumed to result in an equivalent delay in the start of exploration. For a given real oil price increase, the declines in net economic value per barrel (i.e., the "delay costs") are computed by finding the per barrel change in net economic value for fields that are leasable as of mid-1987. The largest delay costs, equal to about 6 percent of net economic value per year of delay, are incurred for the highest valued planning areas including the Gulf of Mexico and Pacific Regions. The relative size of delay costs would be higher if no price increase were expected. (In fact, the delay cost for zero price growth is equal to the discount rate of 8 percent.)

Observe in Table 9 that most entries are negatively valued. This means essentially that within each of the relevant planning areas, a delay in leasing, which results in postponement of the start of exploration activities, will cause a reduction in the net economic value per barrel of oil that could be produced if hydrocarbons were discovered in an average leasable field. For some high-cost, low-valued leasable fields in selected areas, the change in net economic value from delay will be positive. A preliminary analysis of the field size distributions suggests, however, that only a small percentage of the leasable resources in all planning areas will have this attribute, i.e., generally those having NEV's per barrel below one dollar. Moreover, even in planning areas having weighted average (negative) delay costs, there are usually some potentially large prospects worth leasing now.

The net economic value of a barrel of oil and gas in the 2-percent price growth case is higher than in the 1-percent case. Moreover, the set of leasable prospects may differ somewhat for each price scenario. Thus, for a given planning area, the delay costs per barrel as presented in Table 9 are not directly comparable between price scenarios. Of course, for a given price growth assumption, the dollar measures of delay costs do suggest the proper ordering of leasing and investment among areas.



E. Implications of Resource and Net Economic Value Estimates for Schedule Formulation

The guidelines for leasing program formulation developed in section V and the measures of oil and gas resources and net economic value in OCS areas provided in this section can be used to develop a leasing schedule based on economic factors alone. While such a schedule does not reflect consideration of the many noneconomic factors that must be weighed, it provides a base from which adjustments for those factors can be made.

The primary guideline for formulating an economically efficient leasing program is to offer the areas with the highest valued prospects earliest and the areas with the greatest total economic value most frequently. This guideline allows investments to be made in a sequence that would be a reasonable approximation of the most efficient sequence, namely from lowest cost to highest cost deposits.

As Table 7 shows, the Central and Western Gulf of Mexico areas have by far the greatest resource potential. These two areas also have the greatest total net economic value and the greatest total leasable resources. In addition, both areas have substantial resource potential at lower net economic values, which would increase in relative value over time as other areas were leased. The sensitivity of the leasable resources in the Central Gulf of Mexico planning area to changes in the starting oil price is contained in Table 8.

Based on these indicators of the resource and economic potential of the Central and Western Gulf of Mexico, it would be reasonable to schedule sales in these areas for each year in the 5-year program. This would continue the frequency of leasing under the current program. The amount of leasing and the value of leases sold in such annual sales would be expected to decrease unless prices increased suddenly or significant new prospects were identified; however, annual leasing in these two areas is warranted until the unleased inventory is sufficiently depleted to fall more nearly in line with that of other OCS areas.

Outside the Central and Western Gulf of Mexico, the Eastern Gulf of Mexico and the three California planning areas have by far the greatest amount of relatively high valued leasable resources (see Table 7), regardless of oil prices. The Southern California area has the largest portion of these high-valued resources in the top net economic value categories and about 80 percent as many leasable resources as the Eastern Gulf of Mexico and the Central and Northern California planning areas combined in the $14 per barrel scenario. The estimated cost of delaying investments in the leasable resources (at the base case assumption of a 1 percent price growth) is approximately the same for the Northern and Southern California planning areas, somewhat lower for Central California, and somewhat less for the Eastern Gulf of Mexico. Thus, while the relatively high economic value of the resource potential in these areas makes it reasonable to schedule more than one lease sale in each area during the 5-year program, priority for earlier sales should be given to the Southern California area, with its greater resources and high cost of delay.

The South Atlantic and Navarin Basin planning areas also rank high in estimated leasable resources in all but the lowest price scenarios (see Table 6). However, the South Atlantic also has a higher geologic risk than the Gulf of Mexico or areas offshore California and the Navarin Basin has much higher costs. The estimates show that these areas may warrant sales in the 1987-1991 leasing program, perhaps more than one sale if exploration yields positive results. Consideration of industry interest and noneconomic factors must also be weighed in addition to the net economic value basis for scheduling.

The next group of prospective areas in Table 7 are the Beaufort Sea and the Mid-Atlantic. The Beaufort Sea has about one-third more leasable resources then the Mid-Atlantic at higher prices, but a lower net economic value per barrel. However, the Beaufort Sea shows a greater gain in leasable resources from higher prices. With the large quantity of potentially leasable resources in these planning areas it is reasonable to offer both areas at least once in the 1987-1991 program.

The last three areas that have resources which would appear to make potentially worthwhile acquisitions are the St. George Basin, North Atlantic, and Washington-Oregon. They have relatively little resource potential in high-value prospects (see Tables 7), however, the North Atlantic could gain substantially from a higher oil/gas price level. Delay costs are moderate, except for Washington-Oregon, which reflects the relatively high per barrel value of the limited resources in that area. These findings make it worth offering the areas at least once during the 1987-1991 period to allow firms the opportunity to invest in gathering more seismic data and exploring the potentially profitable unleased prospects.

Of the remaining areas with resource potential, the MMS estimates show eight with negligible resource potential; namely, the Chukchi Sea, North Aleutian Basin, Gulf of Alaska, Norton Basin, Kodiak, Hope Basin, Shumagin, and Cook Inlet. None of the latter four areas show any leasable resource at the $29 oil price level. The other areas, with the exception of the Chukchi Sea, are marginal. The Chuckchi Sea shows a large gain in leasable resources with higher oil prices, ranking it about equal with Central and Northern California, however the Chukchi Sea's net economic value is still much lower. To be able to offer these remaining areas if new information should make them more valuable, they might be scheduled for standard or frontier exploration sales.

A further analysis was performed to examine an alternative pricing scenario's effect on leasable resources. Specifically, leasable resources and each planning area's net economic value were estimated with gas priced at two-thirds the Btu--equivalent price of oil. This adjustment was made to reflect the relation between oil and gas prices observed in the market in recent years.

With the assumption of relatively lower gas prices, the Central and Western GOM would still have by far the greatest leasable resource potential. However, the net economic value of these planning areas would decline sharply with the lower gas price. Depending on the starting oil prices, the Central GOM's net economic value would decline between 33 and 50 percent, while the Western GOM's net economic value would decline between 45 and 85 percent. The higher percentages apply to the lower starting prices.



Declines also would be observed for the other planning areas, except for the Beaufort Sea and Chukchi Sea where gas originally was not considered to be economically viable. Depending on the percentage of gas in the planning area and the starting oil price, the net economic value would decline by as little as 18 to 29 percent in Central California to a high of 100 percent at lower prices in the Atlantic and Alaskan planning areas.

If an alternative assumption is made that Alaskan gas is shipped to Japan where it can be sold at a Btu-equivalent price with oil, the Alaskan areas that can produce gas would have increased net economic values because of lower transport costs to Japan and higher gas prices. At an oil price of $29 per barrel the following changes in net economic value versus gas shipment to the west coast with prices two-thirds the Btu--equivalent of oil are expected: Navarin Basin (+ 45 percent), St. George Basin (+ 334 percent), and in addition, the Gulf of Alaska, North Aleutian Basin, and Norton Basin would become leasable. At $24 per barrel, the St. George Basin, Gulf of Alaska, and North Aleutian Basin would be leasable, while the Navarin Basin would have an increase in value of 45 percent. At $19 per barrel the net economic value of the Navarin Basin would increase by about 200 percent.

To examine the effects of prices above or below the range of prices ($14 to $29 per barrel) used for the main analysis, a sensitivity analysis was performed at a $5 increment from the endpoints of the range. Assuming that gas is priced at a Btu--equivalent basis with oil, six planning areas are estimated to have leasable resources for a starting oil price of $9 per barrel. These remaining planning areas and their changes in net economic value from the $14 per barrel scenario are as follows: Central GOM (-73 percent), Western GOM (-91 percent), Southern California (-74 percent), Central California (-89 percent), Northern California (-84 percent), and Washington-Oregon (-79 percent). If gas were priced at two-thirds the Btu--equivalent price of oil, only the CGOM and Southern California would remain in the leasable category with declines in net economic value compared to the similar scenario at $14 per barrel of 84 percent and 78 percent, respectively.

At $34 per barrel, the net economic value of all planning areas would increase because of greater net economic values per barrel, as well as greater quantities of leasable resources at the higher price. However, even at $34 per barrel, 3 planning areas, Shumagin, Lower Cook Inlet, and the Hope Basin would still remain marginal because of low resource levels.

It is important to recall that these analyses are based on a (price) sensitivity analysis around the risked mean recoverable resource estimated for an area. Therefore, a considerable degree of uncertainty remains in all of the estimates. Likewise, although the various tables appear to be accurate to five places, that appearance is misleading and exists only to facilitate and validate calculations. Consequently, the tables presented should be used primarily for ordinal rather than cardinal ranking of planning areas.

14-34

TABLE 6

UNDISCOVERED ECONOMICALLY RECOVERABLE RESOURCES UNLEASED AS OF 5/87

| RANK (1) | PLANNING (2) AREA | CONDITIONAL MEAN OIL (BBO) | CONDITIONAL MEAN GAS (TCFG) | MP hc | RISKED MEAN OIL (BBO) | RISKED MEAN GAS (TCFG) | RISKED BOE (BBOE) |
|---|---|---|---|---|---|---|---|
| 1 | Western Gulf of Mexico | 1.32 | 18.62 | 1.00 | 1.32 | 18.62 | 4.63 |
| 2 | Central Gulf of Mexico | 1.86 | 15.24 | 1.00 | 1.86 | 15.24 | 4.57 |
| 3 | Southern California | 0.89 | 1.30 | 1.00 | 0.89 | 1.30 | 1.12 |
| 4 | Navarin Basin | 3.28 | 4.26 | 0.27 | 0.89 | 1.15 | 1.09 |
| 5 | Mid-Atlantic | 0.24 | 4.21 | 1.00 | 0.24 | 4.21 | 0.99 |
| 6 | South Atlantic | 0.87 | 16.22 | 0.25 | 0.22 | 4.06 | 0.94 |
| 7 | St. George Basin | 1.12 | 9.24 | 0.22 | 0.25 | 2.08 | 0.61 |
| 8 | Eastern Gulf of Mexico | 0.30 | 1.58 | 1.00 | 0.30 | 1.58 | 0.58 |
| 9 | Chukchi Sea | 2.68 | 0.00 | 0.20 | 0.54 | 0.00 | 0.54 |
| 10 | Beaufort Sea | 0.65 | 0.00 | 0.70 | 0.46 | 0.00 | 0.46 |
| 11 | Northern California | 0.42 | 1.86 | 0.60 | 0.25 | 1.12 | 0.45 |
| 12 | North Atlantic | 0.26 | 5.06 | 0.30 | 0.08 | 1.52 | 0.35 |
| 13 | Central California | 0.30 | 0.56 | 0.65 | 0.19 | 0.36 | 0.25 |
| 14 | Washington/ Oregon | 0.18 | 3.26 | 0.20 | 0.04 | 0.65 | 0.15 |
| 15 | Gulf of Alaska | 0.49 | 8.00 | 0.08 | 0.04 | 0.64 | 0.15 |
| 16 | North Aleutian Basin | 0.19 | 1.36 | 0.20 | 0.04 | 0.27 | 0.09 |
| 17 | Norton Basin | 0.28 | 1.55 | 0.15 | 0.04 | 0.17 | 0.07 |
| 18 | Kodiak | 0.15 | 2.92 | 0.05 | 0.01 | 0.13 | 0.03 |
| 19 | Florida Straits | 0.11 | 1.13 | 0.05 | 0.01 | 0.06 | 0.02 |
| 20 | Hope Basin | 0.17 | 1.81 | 0.02 | negligible | 0.04 | 0.01 |
| 21 | Shumagin | 0.05 | 1.42 | 0.03 | negligible | 0.04 | 0.01 |
| 22 | Cook Inlet | 0.18 | 0.32 | 0.03 | 0.01 | 0.01 | 0.01 |

(1) Ranking based on risked BOE

(2) In the Beaufort and Chukchi Sea planning areas, 200 feet water depth is considered to be the limit of current technology. Based on current cost/price relationships and foreseeable technological advances, it is assumed that the conditional mean gas resources estimated to exist in the Alaskan OCS Beaufort Sea and Chukchi Sea Planning Areas are uneconomic.



TABLE 6A

RANGE OF NET ECONOMIC VALUE ESTIMATES FOR LEASABLE RESOURCES AS OF MID - 87

| PLANNING AREA | Risked Economically Recoverable Oil and Gas Resources (MM-BOE) | Fraction of Recoverable Resource That is Leasable | Leasable Resources (1) (MM-BOE) | Net Economic Value per BOE | Total Net Economic Value ($MM) |
|---|---|---|---|---|---|
| Central Gulf of Mexico | 4570 | 0.86 - 0.90 | 3,930 - 4,110 | $2.40 - $7.60 | 9,430 - 31,240 |
| Western Gulf of Mexico | 4630 | 0.82 - 1.00 | 3,790 - 4,630 | $1.90 - $6.80 | 7,200 - 31,480 |
| Southern California | 1120 | 0.34 - 0.73 | 380 - 820 | $2.60 - $6.10 | 990 - 5,000 |
| Navarin Basin | 1090 | 0.00 - 0.72 | 0 - 790 | $0.00 - $2.60 | 0 - 2,050 |
| South Atlantic | 940 | 0.27 - 0.82 | 250 - 770 | $1.60 - $4.10 | 400 - 3,160 |
| Middle Atlantic | 990 | 0.09 - 0.23 | 90 - 230 | $1.00 - $3.90 | 90 - 900 |
| Eastern Gulf of Mexico | 580 | 0.31 - 0.81 | 180 - 470 | $1.00 - $5.10 | 180 - 2,400 |
| Chukchi Sea | 540 | 0.00 - 0.74 | 0 - 400 | $0.00 - $1.50 | 0 - 600 |
| Beaufort Sea | 460 | 0.00 - 0.68 | 0 - 310 | $0.00 - $2.20 | 0 - 680 |
| Central California | 250 | 0.48 - 0.92 | 120 - 230 | $2.00 - $6.90 | 240 - 1,590 |
| Northern California | 450 | 0.40 - 0.91 | 180 - 410 | $2.60 - $6.60 | 470 - 2,710 |
| St. George Basin | 610 | 0.00 - 0.42 | 0 - 260 | $0.00 - $2.90 | 0 - 750 |
| North Atlantic | 350 | 0.03 - 0.20 | 10 - 70 | $1.70 - $3.50 | 20 - 250 |
| Wash/Oregon | 150 | 0.00 - 0.20 | 50 - 60 | $2.60 - $8.10 | 130 - 490 |
| Gulf of Alaska | 150 | 0.00 - 0.22 | 0 - 30 | $0.00 - $1.20 | 0 - 40 |
| North Aleutian Basin | 90 | 0.00 - 0.29 | 0 - 20 | $0.00 - $1.30 | 0 - 30 |
| Norton Basin | 70 | 0.00 | 0 - 20 | $0.00 - $1.70 | 0 - 30 |
| Kodiak | 30 | 0.00 | 0 | $0.00 | 0 |
| Florida Straits | 20 | 0.00 - 0.50 | 0 - 10 | $0.00 - $5.50 | 0 - 60 |
| Hope | 10 | 0.00 | 0 | $0.00 | 0 |
| Shumagin | 10 | 0.00 | 0 | $0.00 | 0 |
| Cook Inlet | 10 | 0.00 | 0 | $0.00 | 0 |

Assumptions:

Range of Oil Prices: $14 - $29 per BOE.
Annual Oil Price Change: 1%.
Real Discount Rate: 8%.
Resources are expressed in Millions of Barrels of Oil Equivalent.

(1) Leasable resources are the risked economically recoverable resources that lie on prospects having a positive private value.

TABLE 7



CONDENSED DISTRIBUTION OF RISKED RECOVERABLE RESOURCES

AS OF MID - 87

| PLANNING AREA | Recoverable But Not Leasable | | | | Net Economic Value per BOE for Leasable Resources: Below $3.00 | | | | $3.00 - $6.00 | | | | $6.00 - $10.00 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | $14 | $19 | $24 | $29 | $14 | $19 | $24 | $29 | $14 | $19 | $24 | $29 | $14 | $19 | $24 | $29 |
| Central Gulf of Mexico | 640 | 500 | 460 | 460 | 2450 | 280 | 50 | 0 | 1480 | 3790 | 2560 | 110 | 0 | 0 | 1500 | 4000 |
| Western Gulf of Mexico | 840 | 140 | 0 | 0 | 3790 | 1640 | 140 | 0 | 0 | 2650 | 3790 | 540 | 0 | 0 | 700 | 4090 |
| Southern California | 740 | 490 | 300 | 300 | 180 | 380 | 190 | 0 | 200 | 250 | 410 | 440 | 0 | 0 | 220 | 380 |
| Navarin Basin | 1090 | 910 | 370 | 300 | 0 | 180 | 720 | 270 | 0 | 0 | 0 | 520 | 0 | 0 | 0 | 0 |
| South Atlantic | 690 | 530 | 260 | 170 | 250 | 410 | 230 | 290 | 0 | 0 | 450 | 460 | 0 | 0 | 0 | 0 |
| Middle Atlantic | 900 | 880 | 760 | 760 | 90 | 110 | 120 | 120 | 0 | 0 | 110 | 110 | 0 | 0 | 0 | 0 |
| Eastern Gulf of Mexico | 400 | 250 | 160 | 110 | 180 | 300 | 90 | 50 | 0 | 30 | 320 | 210 | 0 | 0 | 10 | 210 |
| Chukchi Sea | 540 | 540 | 540 | 140 | 0 | 0 | 0 | 400 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Beaufort Sea | 460 | 460 | 210 | 150 | 0 | 0 | 250 | 310 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Central California | 130 | 60 | 20 | 20 | 120 | 110 | 20 | 0 | 0 | 80 | 160 | 120 | 0 | 0 | 50 | 110 |
| Northern California | 270 | 150 | 40 | 40 | 180 | 120 | 110 | 0 | 0 | 180 | 120 | 180 | 0 | 0 | 180 | 230 |
| St. George Basin | 610 | 610 | 350 | 350 | 0 | 20 | 260 | 260 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| North Atlantic | 340 | 320 | 320 | 260 | 10 | 0 | 0 | 40 | 0 | 10 | 30 | 20 | 0 | 0 | 0 | 10 |
| Wash/Oregon | 100 | 100 | 90 | 90 | 10 | 0 | 10 | 0 | 40 | 50 | 10 | 10 | 0 | 0 | 40 | 50 |
| Gulf of Alaska | 150 | 150 | 150 | 120 | 0 | 0 | 0 | 30 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| North Aleutian Basin | 90 | 90 | 90 | 70 | 0 | 0 | 0 | 20 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Norton Basin | 70 | 70 | 70 | 50 | 0 | 0 | 0 | 20 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Kodiak | 30 | 30 | 30 | 30 | 0 | 10 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Florida Straits | 20 | 10 | 10 | 10 | 0 | 0 | 0 | 0 | 0 | 0 | 10 | 10 | 0 | 0 | 0 | 0 |
| Hope | 10 | 10 | 10 | 10 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Shumagin | 10 | 10 | 10 | 10 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Cook Inlet | 10 | 10 | 10 | 10 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

Assumptions:

Range of Oil Prices: $14 to $29 per BOE.
Annual Oil Price Change: 1%.
Real Discount Rate: 8%.
Resources Expressed in Millions of Barrels of Oil Equivalent.

TABLE 8



SENSITIVITY OF LEASABLE RESOURCE AMOUNTS AND
NET ECONOMIC VALUE (NEV) TO THE STARTING OIL PRICE

| PLANNING AREA | STARTING PRICE: $14 Leasable Resources (MM-BOE) | NEV ($/BOE) | Total NEV ($MM) | STARTING PRICE: $19 Leasable Resources (MM-BOE) | NEV ($/BOE) | Total NEV ($MM) | STARTING PRICE: $24 Leasable Resources (MM-BOE) | NEV ($/BOE) | Total NEV ($MM) | STARTING PRICE: $29 Leasable Resources (MM-BOE) | NEV ($/BOE) | Total NEV ($MM) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Western Gulf of Mexico | 3,790 | $1.90 | $7,201 | 4,490 | $3.20 | $14,368 | 4,630 | $5.10 | $23,613 | 4,630 | $6.80 | $31,484 |
| Central Gulf of Mexico | 3,930 | $2.40 | $9,432 | 4,070 | $3.90 | $15,873 | 4,110 | $5.80 | $23,838 | 4,110 | $7.60 | $31,236 |
| Southern California | 380 | $2.60 | $988 | 630 | $3.20 | $2,016 | 820 | $4.60 | $3,772 | 820 | $6.10 | $5,002 |
| Navarin Basin | 0 | $0.00 | $0 | 180 | $0.70 | $126 | 720 | $1.90 | $1,368 | 790 | $2.60 | $2,054 |
| Middle Atlantic | 90 | $1.00 | $90 | 110 | $2.30 | $253 | 230 | $2.60 | $598 | 230 | $3.90 | $897 |
| South Atlantic | 250 | $1.60 | $400 | 410 | $2.10 | $861 | 680 | $3.30 | $2,244 | 770 | $4.10 | $3,157 |
| St. George Basin | 0 | $0.00 | $0 | 0 | $0.00 | $0 | 260 | $1.50 | $390 | 260 | $2.90 | $754 |
| Eastern Gulf of Mexico | 180 | $1.00 | $180 | 330 | $2.00 | $660 | 420 | $3.80 | $1,596 | 470 | $5.10 | $2,397 |
| Chukchi Sea | 0 | $0.00 | $0 | 0 | $0.00 | $0 | 0 | $0.00 | $0 | 400 | $1.50 | $600 |
| Beaufort Sea | 0 | $0.00 | $0 | 0 | $0.00 | $0 | 250 | $1.40 | $350 | 310 | $2.20 | $682 |
| Northern California | 180 | $2.60 | $468 | 300 | $3.50 | $1,050 | 410 | $4.90 | $2,009 | 410 | $6.60 | $2,706 |
| North Atlantic | 10 | $1.70 | $17 | 30 | $2.40 | $72 | 30 | $4.20 | $126 | 70 | $3.50 | $245 |
| Central California | 120 | $2.00 | $240 | 190 | $2.60 | $494 | 230 | $5.10 | $1,173 | 230 | $6.90 | $1,587 |
| Wash/Oregon | 50 | $2.60 | $130 | 50 | $4.50 | $225 | 60 | $6.20 | $372 | 60 | $8.10 | $486 |
| Gulf of Alaska | 0 | $0.00 | $0 | 0 | $0.00 | $0 | 0 | $0.00 | $0 | 30 | $1.20 | $36 |
| North Aleutian Basin | 0 | $0.00 | $0 | 0 | $0.00 | $0 | 0 | $0.00 | $0 | 20 | $1.30 | $26 |
| Norton Basin | 0 | $0.00 | $0 | 0 | $0.00 | $0 | 0 | $0.00 | $0 | 20 | $1.70 | $34 |
| Kodiak | 0 | $0.00 | $0 | 0 | $0.00 | $0 | 0 | $0.00 | $0 | 0 | $0.00 | $0 |
| Florida Straits | 0 | $0.00 | $0 | 10 | $2.30 | $23 | 10 | $4.00 | $40 | 10 | $5.50 | $55 |
| Hope Basin | 0 | $0.00 | $0 | 0 | $0.00 | $0 | 0 | $0.00 | $0 | 0 | $0.00 | $0 |
| Shumagin | 0 | $0.00 | $0 | 0 | $0.00 | $0 | 0 | $0.00 | $0 | 0 | $0.00 | $0 |
| Cook Inlet | 0 | $0.00 | $0 | 0 | $0.00 | $0 | 0 | $0.00 | $0 | 0 | $0.00 | $0 |

Assumptions:

- Gas priced on a Btu-equivalent basis with oil (ALASKAN GAS SHIPPED TO THE WEST COAST)
- Annual price change = .01
- Real discount rate = .08
- Resources expressed in millions of risked equivalent barrels
- Costs used for the $19/BOE and $24/BOE scenarios assume no nominal increase from 1984 levels because of low demand for drilling services. The $29/BOE scenario assumes that costs increase at the inflation rate from 1984 to 1987 due to higher demand for factors of production at the higher resource price. The $14/BOE scenario assumes a 10 percent decrease in costs from the $19/BOE 1984 levels due to extremely low demand for drilling services.

TABLE 9

SIMPLE AVERAGE ANNUAL DOLLAR CHANGE IN NET ECONOMIC VALUE PER BARREL FOR LEASABLE RESOURCES FROM A ONE-YEAR DELAY IN LEASING

| Price = | $14/BOE | | | $19/BOE | | | $24/BOE | | | $29/BOE | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Discount Rate= | 8% | 8% | 6% | 8% | 8% | 6% | 8% | 8% | 6% | 8% | 8% | 6% |
| Price Growth = | 1% | 2% | 2% | 1% | 2% | 2% | 1% | 2% | 2% | 1% | 2% | 2% |
| PLANNING AREA | | | | | | | | | | | | |
| Central Gulf of Mexico | -.13 | -.13 | -.11 | -.22 | -.22 | -.19 | -.35 | -.35 | -.31 | -.46 | -.46 | -.41 |
| Western Gulf of Mexico | -.09 | -.09 | -.07 | -.17 | -.17 | -.14 | -.29 | -.29 | -.26 | -.40 | -.40 | -.36 |
| Southern California | -.14 | -.13 | -.10 | -.16 | -.16 | -.13 | -.25 | -.25 | -.21 | -.34 | -.34 | -.29 |
| Navarin Basin | [+.01] | [.00] | [+.01] | +.01 | .00 | +.01 | -.07 | -.08 | -.07 | -.11 | -.13 | -.11 |
| South Atlantic | -.07 | -.08 | -.08 | -.10 | -.12 | -.12 | -.16 | -.18 | -.18 | -.21 | -.24 | -.23 |
| Middle Atlantic | -.02 | -.03 | -.03 | -.10 | -.11 | -.10 | -.11 | -.12 | -.12 | -.19 | -.25 | -.24 |
| Eastern Gulf of Mexico | -.01 | -.02 | .00 | -.08 | -.08 | -.05 | -.19 | -.19 | -.16 | -.29 | -.29 | -.25 |
| Chukchi Sea | +.15* | +.13* | +.15* | +.08* | +.06* | +.07* | [-.03] | [-.06] | [-.05] | -.09 | -.12 | -.12 |
| Beaufort Sea | +.11* | +.09* | +.11* | [-.01] | [-.03] | [-.03] | -.05 | -.08 | -.08 | -.10 | -.14 | -.14 |
| Central California | -.09 | -.09 | -.06 | -.12 | -.11 | -.07 | -.28 | -.27 | -.22 | -.40 | -.38 | -.31 |
| Northern California | -.14 | -.12 | -.09 | -.18 | -.17 | -.14 | -.26 | -.25 | -.21 | -.37 | -.36 | -.30 |
| St. George Basin | +.18* | +.18* | +.18* | [-.03] | [-.03] | [-.02] | -.03 | -.05 | -.03 | -.12 | -.14 | -.12 |
| North Atlantic | -.08 | -.08 | -.07 | -.11 | -.12 | -.11 | -.23 | -.24 | -.22 | -.16 | -.18 | -.17 |
| Wash/Oregon | -.13 | -.12 | -.09 | -.25 | -.24 | -.19 | -.36 | -.34 | -.27 | -.40 | -.38 | -.30 |
| Gulf of Alaska | +.24* | +.23* | +.24* | [-.01] | [-.03] | [-.02] | [+.02] | [-.01] | [.00] | -.02 | -.04 | -.03 |
| North Aleutian Basin | +.23* | +.22* | +.23* | [-.01] | [-.02] | [-.02] | [+.04] | [+.05] | [+.04] | -.02 | -.05 | -.04 |
| Norton Basin | +.27* | +.27* | +.27* | [-.03] | [-.04] | [-.03] | [-.04] | [-.06] | [-.05] | -.04 | -.06 | -.04 |
| Kodiak | +.17* | +.16* | +.17* | [-.04] | [-.06] | [-.05] | [-.03] | [-.06] | [-.05] | [-.09] | [-.12] | [-.11] |
| Florida Straits | [-.02] | [-.03] | [-.02] | -.10 | -.11 | -.10 | -.22 | -.22 | -.21 | -.31 | -.32 | -.29 |
| Hope Basin | +.25* | +.24* | +.25* | [.00] | [-.01] | [.00] | [+.02] | [.00] | [+.02] | [-.06] | [-.08] | [-.07] |
| Shumagin | +.21* | +.19* | +.21* | [-.05] | [-.06] | [-.06] | [-.03] | [-.06] | [-.05] | [-.11] | [-.14] | [-.13] |
| Cook Inlet | +.17* | +.16* | +.17* | [-.03] | [-.05] | [-.04] | [-.05] | [-.07] | [-.06] | [-.09] | [.11] | [-.10] |

Assumptions:

Range of Oil Prices: $14 to $29 per BOE.
Annual Oil Price Change: 1%.
Real Discount Rate: 8%.
Resources Expressed in Millions of Barrels of Oil Equivalent.

Numbers followed by asterisks represent Net Economic Values that would result based on the use of field sizes from the $29 case.

Numbers in brackets indicate the change in Net Economic Value that results if a field with After-Tax Net Present Value of zero is used.



Because of the manner of categorizing a planning area's resources (e.g., into 9 field sizes and 2 water depths), a significant amount of resources may be classified as nonleasable even though a more refined analysis would have shown some fraction of these resources to have positive private values. This distinction is particularly important when the tables show that at a given starting price, a planning area has no leasable resources.

To account for this effect, a new category of resources is defined, and referred to as "marginally leasable." These are risked economically recoverable resources that lie on a prospect category having a negative private value, but which would become positively valued if the starting resource price is increased by $5 per BOE. (Similar absolute adjustments are made to costs when prices are increased as was the case for price decreases, except for a difference in sign). Assuming a 1 percent real resource price growth and gas priced on a Btu-equivalent basis with oil, the following results are calcualted.

At $29 per barrel, all OCS planning areas except for Kodiak, Hope Basin, Shumagin, and the Lower Cook Inlet would have leasable resources.

A decline in price from $29 to $24 per barrel would move four additional OCS areas to the marginally leasable category: Chukchi Sea, Gulf of Alaska, North Aleutian Basin, and Norton Basin.

With a further decrease in oil price to $19 per barrel, two additional planning areas, Beaufort Sea and St. George Basin, move to the marginally leasable category. A decline in oil prices to $14 per barrel adds an additional category, the Navarin Basin (the last Alaskan planning area). At this point 10 planning areas (encompassing most of the Atlantic, Pacific, and Gulf of Mexico OCS) would still be considered to have leasable resources.

However, if an alternative assumption, pricing gas at two-thirds the Btu--equivalent price of oil were made, the price at which the various planning areas became marginally leasable changes dramatically.

At $29 per barrel of oil, and $3.44 per mcf for gas, seven Alaskan OCS planning areas have no prospects with positive private values: the Gulf of Alaska, North Aleutian Basin, Norton Basin, Kodiak, Hope Basin, Shumagin, and the Lower Cook Inlet.

A decline in oil prices from $29 to $24 per barrel with a proportional decrease in gas prices (at two-thirds the Btu--equivalent price of oil) to $2.85 per mcf moves the St. George Basin and the Chukchi Sea (which is not affected by gas prices) to the marginally leasable category.

The next $5 per barrel decrease in oil prices to $19 per barrel (and $2.25 per mcf) moves one additional planning area to the marginally leasable category, the Beaufort Sea (which is not affected by gas prices).

A decline in oil prices to $14 per barrel, and $1.66 per mcf adds five additional planning areas to the marginally leasable category: the Navarin Basin, Washington-Oregon, the North, Middle, and South Atlantic. At those prices only the GOM and California planning area would be considered to have leasable resources.



## VII. Estimating Procedures Used for Analysis of OCS Planning Areas

### A. Introduction

Formulation of a 5-year OCS leasing schedule requires determination of where, when, and how the oil and gas resources that are potentially located in the planning areas would be made available for sale to private industry. In addressing these salient issues, it was important to develop the estimates presented in the previous section and in Appendix E relating to the geologic and economic characteristics of the designated OCS planning areas. This section gives a technical description of the methods and assumptions used to generate these estimates.

### B. Geologic Analysis

Estimates of oil and gas resources and economic values for the designated OCS planning areas allow a ranking of planning areas to be made. This is an important first step in designing a lease schedule. The absolute size of the economic values within a planning area provide for a comparison with the associated environmental risks and costs to determine the overall net social value of each planning area.

The basic unit of oil and gas resources that was measured is called economically recoverable oil and gas resources. This estimate represents the magnitude of oil and gas equivalent barrels that are profitable for a lessee to produce, given that the resource has already been discovered. In this context, economically recoverable resources are "conditional," i.e., they are measured free of the risk of discovery and production. For a given distribution of conditional economically recoverable oil and gas resources, the average value of the distribution is the mean conditional economically recoverable oil and gas resource level.

When the possibility for success/failure in discovery or production of the resources is taken into consideration, economically recoverable resources are expressed in terms of "risked" or "expected" resources. This means that production on a prospect will occur only if three specific states of nature exist. First, the planning area must be hydrocarbon-prone. Second, the geologic prospect upon which the resources could occur must contain hydrocarbons. Finally, the amount of hydrocarbons found must be economical to produce. The resulting joint probability is referred to as the "probability of economic success."

Assuming that the probability of success and the conditional resource size are independent, the product of the mean conditional economically recoverable resource level and the economic success probability results in an estimate of producible resources on the geologic prospect and is denoted by the term "risked conditional economically recoverable resources," or simply "risked recoverable resources."

Calculation of the conditional resource sizes and economic successes for exogenously selected geologic prospects in the OCS planning area was done using a computer simulation model called PRESTO, an acronym for "probabilistic resource estimates--OCS." The data available for this 5-year assessment were taken from stratigraphic tests, well logs, and geophysical analyses. These data were generally adequate to identify potential prospects and to determine their approximate size. In some instances, however, hypothetical prospects based on extrapolations of known trends and appropriate geological analogs were included. This was necessary because some areas lacked sufficient data to adequately identify individual prospects. Therefore, with the hypothetical prospects it was possible to analyze the resource potential of an area on a prospect-by-prospect basis. In some areas, sufficient stratigraphic data may exist to identify different resource potential on a horizon-by-horizon basis, as well as on a prospect-by-prospect basis. Therefore, the PRESTO methodology was designed to accommodate an analysis of hydrocarbon resource potential for an area on both a horizon-by-horizon and a prospect-by-prospect basis.

A volumetric method was employed for the analysis of the resource potential of individual prospective zones. Seven variables were considered in determining potential hydrocarbon volumes: (1) productive area (acres), (2) pay thickness (feet), (3) proportion of zone pay thickness consisting of oil, (4) oil recovery factor for oil reservoirs (barrels per acre-foot), (5) gas-oil ratio (cubic feet of solution gas per barrel), (6) gas recovery factor for gas reservoirs (thousands of cubic feet of gas per acre-foot), and (7) condensate yield ratio for liquids produced from gas reservoirs (barrels per million cubic feet of gas). Either single point values for each of these variables or parameters describing a probability distribution were used.

In addition to the reservoir parameters, several other inputs were used. For each zone in each prospect, a zone geologic risk factor was estimated. This risk factor represents the overall probability that the zone in the prospect under consideration will be dry. For each prospect, two additional input values were required--a "minimum economic field size" for the prospect and a prospect geologic risk factor. The minimum economic field sizes were developed using a combination of sophisticated cash flow models, general rules, and empirical data on producing tracts. These values represent the minimum quantity of oil and gas that must be present in a prospect to be considered economically producible given current and expected future cost/price relationships and technological trends. The minimum economic field size allows for variations in costs associated with the exploration and development of prospects in differing cost regimes, such as deep water vs. shallow water.

The prospect risk factor represents the probability that the prospect as modeled would not contain hydrocarbons, without including additional considerations unique to individual zones. In addition to the zone and prospect geologic risk factors, a probability which applies to the area under consideration as a whole was required. This area risk factor represents the likelihood that no prospect as modeled would contain hydrocarbons.

The prospect risk factor controls the degree of statistical dependence for discovery among the individual zones. A high value indicates a high degree of dependence, which implies that a discovery in one zone greatly increases



the chance for success or discoveries in other zones. Conversely, a low value implies that the risks associated with individual zones are unrelated, i.e., a discovery in one zone has little effect on the chances for discovery in other zones. The area risk factor works in the same manner; however, it controls the dependency for discoveries among the individual prospects rather than individual zones.

Monte Carlo or range-of-values simulation techniques were used to develop area specific probability distributions of economically recoverable resources, conditional on that area being hydrocarbon prone. This technique explicitly recognizes the probabilistic nature of the variables affecting the resource assessment and calculates a large number of possible outcomes, based upon random samples from the probability distributions of the various inputs. The Monte Carlo technique generated a range of resource estimates for a planning area with the probability of each value occurring being a direct consequence of the uncertainty in the geological and engineering data (e.g., area extent and thickness of the hydrocarbon pay zone, recovery factors, and which prospects and/or combination of prospects will contain hydrocarbons). Specific oil and gas amounts corresponding to the mean value, 5th percentile, and 95th percentile values of the distribution for barrel of oil equivalents of total resources were reported. Also reported was the probability that no economically recoverable resources exist in the area under consideration.

It is worth noting that, under economic conditions expected to exist, prospects that are not profitable to develop are not considered by PRESTO. In this sense, the resource estimates are conservative, and the sensitivity of resource potential to large increases in the price of oil tends to be understated.

The most important outputs produced by PRESTO for each planning area are: (1) identification of the remaining prospects that were partially or fully unleased as of March 1985, (2) their probability of economic success, (3) their mean conditional recoverable resource sizes, and (4) their minimum economic field sizes. In all, over 2,400 prospects were evaluated. (The effect of lease sales during the 1985 to 1986 period on the unleased resource inventory was calculated exogenously from PRESTO.)

The MMS divided the OCS into 26 planning areas. PRESTO was then run for each area. Four areas (Aleutian Basin, Bower Basin, St. Matthew-Hall, and Aleutian Arc) were dropped from further consideration in this appendix after their recoverable hydrocarbon potential was computed to be insignificant.

C. Economic Analysis

After the PRESTO outputs were produced, a procedure was developed to compute appropriate measures of economic value for the prospects within each planning area. The inputs needed to conduct the economic analysis, using the TSL80 computer leasing model, did not correspond perfectly with the previously designated outputs of PRESTO (see "Guide for Using the Leasing Simulation Computer Program TSL80 (Version OCT16)", Minerals Management Service, U.S. Department of the Interior, October 23, 1984).

For example, the probability input requirement for TSL80 is not "economic success" which the PRESTO runs developed; it is "geologic success" (i.e., the joint probability of the planning area being hydrocarbon-prone and the prospect containing hydrocarbons). This is the case because TSL80 endogenously computes the likelihood of producing the resource after a discovery of a given amount has occurred. Fortunately, one of the intermediate outputs of PRESTO is called "non-producing trials." Knowledge of this and the total number of simulation trials permitted the calculation of the geologic success used in the TSL80 calculations.

A more complicated problem arose regarding the TSL80 input parameters for the conditional resource distribution. TSL80 requires that the mean, standard deviation, and shape of the input distribution be expressed in terms of geologic resources, not economic resources, as is the case with PRESTO outputs. However, the mean conditional economically recoverable resource size for a geologic prospect as described by PRESTO can be expressed as the expectation of a geologic distribution of resources for that prospect truncated at the minimum economic field size. In order to find the mean conditional size of the geologic distribution of resources for a given prospect, it was necessary to derive the expectation of the untruncated distribution.

To accomplish this, the following methodology was developed. For each prospect, the mean of the conditional geologic resource distribution can be expressed as the weighted average of the mean conditional size of economically recoverable resources (a PRESTO output) and the mean of truncated left tail of the original geologic distribution. By approximating the latter distribution as triangular, with mode = maximum value = minimum economic field size, the mean of this second distribution was found to be two-thirds of the minimum economic field size. The weights applied to each mean value were proportional to the areas of each distribution, with sum of weights equal to unity, i.e., the ratio of "successful" trials to total trials for developable resources (or the economic success given that the planning area is hydrocarbon prone) and the ratio of "unsuccessful" trials to total trials for the left tail of the original distribution.

The shape of the geologic distributions of field sizes was assumed to be lognormal. This derives from the multiplicative processes that account for hydrocarbons. Empirical evidence of discovered fields supports this assumption.

The final parameter derived was the variance of the field size distributions. In each of the four OCS Regions, the standard deviation relative to the mean of the conditional geologic resource size, known as the coefficient of variation, was analyzed for selected past sales using data produced by the official tract evaluation model called MONTCAR. Then, assuming the geologic success probability, TSL80 was run with different values of the coefficient of variation to determine the ones which best produced the associated economic success rates. This procedure permitted the selection of a representative parameter for the coefficient of variation for geologic prospects in each Region (see Table 10).



TABLE 10

REGIONAL INPUTS USED IN ECONOMIC EVALUATIONS

| Region | Input: Coefficient of Variation for MCGR* | Input: Water Depth Demarcation (meters) |
|---|---|---|
| Alaska | 1.00 | ** |
| Atlantic | 1.00 | 200 |
| Gulf of Mexico | 0.36 | 400 |
| Pacific | 0.36 | 200 |

* MCGR = mean conditional geologic resources

** Area dependent and ranges from 200 meters in ice-free locations--Gulf of Alaska, etc., to 20 meters in sites such as the Beaufort and Chukchi Seas.

Within a planning area, measures of economic value per barrel differ by field size primarily because of the fixed nature of exploration costs and economies of scale in platform construction. Nevertheless, even for fields of a given size, the per barrel values tend to vary depending upon water depth, the fraction of the field which has already been leased, and other factors such as distance from existing pipelines.

The water-depth parameter was divided into two categories for each of the four Regions (see Table 10). The demarcation line was selected to coincide with that isobath currently used to distinguish between tracts which receive the one-sixth (shallow water) and those receiving one-eighth (deep water) fixed royalty rates. The selection of the relevant isobaths for royalty terms is based on identification of the location of the most pronounced change in development costs and technology in each Region.

The original size of fields that are now partially leased was identified from the "leased" and "unleased" sections of the PRESTO runs. Distance from pipelines was incorporated as part of the transportation cost scenario for a given field size/water-depth/planning area configuration.

At this stage, a decision was made on the specific field sizes to be analyzed using TSL80. A statistical analysis was conducted to determine whether the geologic success (GS) was related to the mean conditional geological resource (MCGR) size. These tests showed conclusively that, with the exception of a few special cases, there was little or no significant relationship between these variables within a planning area. As a result, only one GS rate typically had to be specified for tracts within a given water depth of a planning area. For each of the planning areas, a distribution of MCGR by water depth was computed for unleased prospects. These distributions were then segmented into nine categories of field sizes. Each category was run through TSL80, using the geological parameters discussed earlier as well as the economic assumptions described in the following subsection.

The relevant TSL80 outputs for each field size, water depth, and planning area consisted of estimates of economic risk, conditional and risked economically developable resources, the after-tax (private) value and the net economic (public) value. These outputs formed the basis for the summary tables presented in section VI.

D. Economic Assumptions

The primary economic parameters used in the TSL80 computer model were capital costs (platforms and wells) and production profiles, transportation modes and costs, prices per barrel of oil equivalent, public and private opportunity costs of capital, and inflation rates. The input assumptions used for these parameters are discussed in this section. All dollar amounts are expressed in dollars as of 5/87, except for the discussion on oil prices.



1. Capital Costs

The capital costs were determined parametrically and differed not only from planning area to planning area, but also differed within planning areas by water depth (shallow versus deep) and field size. Costs for wells, platforms, etc., were the lowest in shallow water areas of the Gulf of Mexico where extensive infrastructure already exists to support oil and gas operations. The highest capital cost levels were prevalent in deepwater frontier areas and the arctic waters off Alaska. This means that an appropriately larger minimum economic field size (compared to that in the Gulf of Mexico) is necessary for production, given that hydrocarbons have been found on the prospect. As a result, capital costs ranged from tens of million of dollars for a small field in shallow water in the Gulf of Mexico to well over a billion dollars for a large field in deepwater frontier or arctic areas.

In addition, well and production costs used for the $24/BOE and $19/BOE scenarios assume no nominal increase from 1984 levels because of low demand for drilling services. However, with the high oil price case ($29/BOE), well and production costs are assumed to increase at the inflation rate from 1984 to 1987 due to higher demand for factors of production at the higher resource price. The $14/BOE scenario assumes a 10 percent decrease in well and production costs from the $19/BOE 1984 levels due to extremely low demand for drilling services.

The representative minimum recoverable economic field sizes listed below show the diverse intraplanning and interplanning area capital costs.

Atlantic--Minimum economic field sizes ranged from 1 to 2 million (conditional) barrels in shallow water to 280 million barrels in deep water, with a cluster of deepwater fields in the 100- to 150-million barrel range. Costs varied from the tens of millions of dollars for small fields in shallow water to over $1 billion for large fields in deep water.

Gulf of Mexico--Minimum economic field sizes ranged from 1 to 2 million barrels in shallow water to 190 million barrels in deep water, with a cluster of deepwater fields in the 80- to 120-million barrel range. Costs varied from tens of millions of dollars for small fields in shallow water to over 1 billion dollars for large fields in deep water.

Pacific--Minimum economic field sizes ranged from 9 to 14 million barrels in shallow water to 123 million barrels in deep water, with a cluster of deepwater fields in the 40- to 80-million barrel range. Costs varied from the tens of millions of dollars for small fields in shallow water to the high hundreds of millions of dollars for large fields in deep water.

Alaskan--Minimum economic field sizes ranged from 67 to 100 million barrels in shallow water in non-arctic areas to over 200 million barrels in arctic areas. The largest minimum economic field sizes were 225 million barrels in non-arctic areas to over 440 million barrels in arctic areas. Costs varied from the hundreds of millions of dollars for small fields in non-arctic areas to billions of dollars for large fields in arctic areas.

Production profiles also differed among planning areas with currently producing areas requiring, in general, less time for exploration, delineation, and development than frontier areas. Discount factors for regional production profiles and revenue streams are presented in Table 11 and the timing of representative production profiles is presented in Table 11A.

2. Transportation Costs

Transportation costs differed from planning area to planning area due primarily to the existence or lack of extensive pipeline systems. This difference is significant because transportation costs are subtracted from the expected market price in estimating the net economic value of oil and gas in each OCS planning area. Currently, the Central and Western Gulf of Mexico and, to a lesser extent, the California OCS have extensive pipeline systems, including a network of oil and gas gathering systems and trunk lines. Although pipelines are generally used to bring resources ashore from the California OCS, tankers may be used to transport oil to either west or gulf coast refineries. In areas currently not under production (e.g., the Atlantic and Alaska), the transportation mode cannot be determined until the amount of recoverable resources is known. Pipeline transport is the preferred alternative; however, tankering of oil may be used for environmental considerations or because resource levels do not economically justify laying pipelines.

For our analysis, the following transportation cost assumptions were made:

Atlantic--Pipelines will be used to transport oil and gas to shore for processing at facilities along the Atlantic coast. If the discovered reserves are too low to justify pipelines, tankers would be used. Transport costs were $2.75 per barrel for oil and $4.70 per barrel of oil equivalent (BOE) for gas.

Gulf of Mexico--Pipelines will be used to transport oil and gas to shore for processing at gulf coast facilities. If discovered reserves in the Eastern Gulf are too low to justify pipelines, tankers would be used. Transport costs were $0.50 per barrel for oil and $0.50 per BOE for gas in the shallow water portions of the Central and Western GOM; $1.25 per barrel for oil and per BOE for gas in the deep water portions of the Central and Western GOM and in shallow waters of the Eastern GOM; and $1.75 per barrel of oil and per BOE for gas in the deepwater Eastern GOM.

Pacific--Pipelines will generally be used to transport oil and gas to shore. Depending on location of landed oil, pipelines or tankers would be used to transport oil to refineries. If discovered resources are too low to justify pipelines, tankers would be used to transport oil directly to refineries. Transport costs ranged from $0.40 to $1.75 per barrel for oil and $2.10 to $6.32 per BOE for gas.



Alaska--Pipelines will be used to transport oil and gas to shore-based facilities. Oil will then be transported by tanker to west coast refineries. (If oil production from Alaskan OCS areas were to be shipped to the Gulf of Mexico for refining, its net economic value would decrease by about $0.75 per barrel.) Gas, on the other hand, would go to a liquefaction plant for processing and then be shipped via LNG tanker to a vaporizer in the Los Angeles area. Pipelines, terminal facilities, etc., would be shared by OCS planning areas whenever possible. Transport costs of Alaskan production to the west coast are shown in Table 12. (If each Alaskan OCS area were totally dependent on its own production to support pipelines and terminal facilities, transport cost for oil would increase by $5 or $6 per barrel over those listed in the table.) These assumptions for Alaskan transportation costs are for the 5-year program section 18 analysis only and should not be interpreted to reflect the actual transportation scenario which will be selected for future production.

The legalization of oil exports from Alaska to Japan could have a major positive effect on the net economic values of the Alaskan OCS planning areas. The primary reason for the increase in net economic value is lower oil transport costs from Alaska to Japan. The lower oil transport costs would result from the shorter travel distance to Japan than continental U.S. markets and no requirement to use Jones Act tankers in international trade, which would also greatly lower transportation costs. Preliminary estimates from the MMS Alaska regional office indicate that shipment of Alaskan oil to Japan could result in $3 to $4 per barrel lower transport costs.

The major effects of the lower transport costs is an increase in net economic value for the various Alaskan OCS planning areas. Assuming that transport costs are $3 per barrel lower, the per barrel increase in net economic value for the Alaskan OCS planning areas ranges from $0.44 to $0.72. The overall effect is an increase in aggregate net economic value not only because per barrel net economic values have increased, but also because the quantity of leasable resources may increase at some prices with lower transport costs.

## TABLE 11

Representative Regional Discount Factors for Production and Revenue

| Region | Water Depth | Production Discount Factor* | Revenue Discount Factor** |
|---|---|---|---|
| Gulf of Mexico | Shallow | 0.362 | 0.410 |
| | Deep | 0.295 | 0.345 |
| Pacific | Shallow | 0.368 | 0.418 |
| | Deep | 0.295 | 0.345 |
| Atlantic | Shallow | 0.266 | 0.314 |
| | Deep | 0.228 | 0.276 |
| Alaska | Shallow | 0.150-0.243 | 0.190-0.293 |
| | Deep | 0.150-0.243 | 0.190-0.293 |

* Represents the ratio of the discounted value of gross production to the undiscounted value of gross production, for constant real oil prices.

** Represents the ratio of the discounted value of gross production for oil prices increasing a 1 percent annually, to the undiscounted value of gross production for constant real oil prices.

## TABLE 11A

Representative Regional Production Profiles

| Region | Water Depth | Years for Exploration and Delineation | Years from Delineation to Production | Build Up To Peak Production | Years at Peak | Maximum Years in Decline |
|---|---|---|---|---|---|---|
| Gulf of Mexico | Shallow | 3 | 1 | 6 | 2 | 15 |
| | Deep | 7 | 1 | 6 | 2 | 15 |
| Pacific | Shallow | 3 | 2 | 4 | 2 | 15 |
| | Deep | 7 | 1 | 6 | 2 | 15 |
| Atlantic | Shallow | 6 | 2 | 6 | 2 | 15 |
| | Deep | 6 | 4 | 6 | 2 | 15 |
| Alaska | Shallow | 7 | 5 | 6 | 2 | 15 |
| | Deep | 9 | 4 | 9 | 3 | 15 |



## TABLE 12

TRANSPORTATION COST (5/87) TO THE WEST COAST (DOLLARS/BOE)

| Alaskan Planning Area | Oil | Gas |
|---|---|---|
| Chukchi Sea | 9.90 | 27.60 |
| Beaufort Sea | 6.60 | 27.60 |
| Gulf of Alaska | 4.40 | 19.85 |
| Hope Basin | 9.90 | 29.45 |
| Kodiak | 4.40 | 22.95 |
| Cook Inlet | 4.40 | 26.00 |
| Navarin Basin | 6.60 | 22.60 |
| North Aleutian Basin | 5.00 | 23.25 |
| Norton Basin | 6.60 | 26.00 |
| Shumagin | 5.00 | 23.85 |
| St. George Basin | 6.00 | 18.00 |

3. BOE (Oil and Gas) Prices

In establishing the starting landed prices of oil (i.e., refiners' acquisition cost), OCS crude oil was assumed to compete with imports. Initially, the starting landed prices of crude oil were derived from the average free on board world price weighted by export volume in July 1984, (see Weekly Petroleum Status Report, July 18, 1984). An additional charge for shipping costs (see DOE/EIA Monthly Energy Review) to the Gulf of Mexico was added to arrive at an adjusted landed price. This price was then further adjusted to account for the differences in the expected quality of OCS crude in the different regions versus imported crude to arrive at a quality adjusted landed price at the gulf coast in July 1984. Further adjustments for market factors were made to estimate a base case price at the west coast in July 1984. This price was adjusted to take into account projected price changes through mid-1987.

As suggested by actual recent price changes, it is unlikely that the next several years will see a smooth balance of supply and demand which keeps prices stable. It appears more likely that periodic (and possibly major) price fluctuations could become the norm. For example, in the spring of 1983, oil markets were seriously weakened and a disunified OPEC finally responded with a $5 per barrel price cut in the Saudi marker crude. In early 1986, oil prices fell precipitously from around $28 per barrel to below $10 per barrel.

To capture the effects of alternative price paths and fluctuations throughout the 1987 to 2020 period, both a low and high price scenario were developed and estimates made to determine the sensitivity of leasable resources to these price changes and fluctuations. For this proposed program analysis, a range of landed prices (1984 dollars) from $14 to $29 was used. In addition, sensitivity of leasable resources to a $9 price also was examined. Adjustments were made to the 1984 prices by assuming constant prices through mid-1985 and then beginning in mid-1985 to account for inflation at a 5-percent annual rate and oil price increases typically at a 1 percent real rate. The 5-percent annual inflation rate was chosen because DRI forecast average annual rates of change in the Wholesale Price Index between 1984 and 2010 ranging from a low of 3.1 to a high of 6.5 percent (DRI, Inc., Energy Review, Vol. 8, no. 3, Autumn 1984).

For our analysis, the following area-specific price assumptions were made:

Atlantic and Gulf of Mexico--The east and gulf coast crude markets are dominated primarily by imports of relatively low sulfur (sweet) and high gravity (light) crudes. There is little difference in point-of-entry prices for a given quality of crude at the east and gulf coasts. The July 1984 export price of $28.65 was increased by $1.06 for transportation and by $0.64 for quality to arrive at an equivalent landed price of $30.35. This price was used in the high price scenario and actual prices of $25.35, $20.35, and $15.35 were used for the other price cases. Adjusting for inflation and real price increases in 1985 and 1986, the mid-1987 prices for the east and gulf coasts scenarios were $34.10, $28.50, $22.85, and $17.25 per BOE, respectively.



West Coast and Alaska--The west coast market is dominated by higher sulfur (sour) and lower gravity (heavy) crudes from California, Alaska, and Indonesia. There is a significant difference in crude prices at the wellhead between California and Alaskan crudes because the latter must be transported via pipeline and tanker to the west or gulf coast refineries. After adjusting for transportation and API gravity, the export price of $28.65 became a July 1984 quality adjusted landed import price of $29.40 at the gulf coast. In estimating a west coast price for Pacific and Alaskan crude, the July 1984 price was decreased by $1.00 to account for the observed price differential between landed crude at the gulf and west coast markets, resulting in July 1984 price of $28.40. This price was used in the high price scenario; actual prices of $23.40 $18.40, and $13.40 were used for the other price cases. After increases for inflation and real price growth in 1985 and 1986, the mid-1987 prices for the west coast became $31.90 per BOE for the high case and $26.30, $20.65, and $15.05 per BOE for the other price scenarios, respectively.

The entire set of price assumptions is summarized in Table 12A.

The extreme volatility in the oil markets since December 1985, has created more than the usual amounts of uncertainty regarding future prices. In general, professional economic forecasters believe that crude oil prices will decrease in real terms through the end of the 1980's before increasing faster than inflation in the 1990's. Four different oil price scenarios are used by MMS to reflect the wide range of future price uncertainty. For simplicity of analysis and comparison, each scenario is "indexed" by a relevant starting price. Otherwise, MMS economic parameters for inflation, real oil price increases, transportation costs, and quality adjustments are the same for each of the four price scenarios. Table 12B and 12C, respectively, present MMS oil price scenarios, as well as projections of three prominent national economic forecasting consultants.

As indicated by the professional price projections, the range of estimates of future world oil prices is wide. The differences between the MMS price scenarios and the forecasts by DRI, Wharton, and Chase are greatest in the early years. Initially, MMS generally uses higher prices for 1987, but the spread decreases in later years because of MMS use of a lower annual nominal price increase of 6 percent (5 percent inflation and 1 percent real price increases). By 1995, MMS' two lower price scenarios track those presented by the private consultants in Table 12C and are on the conservative side compared to DRI in later years when most OCS production is expected to be realized as a result of the 5-year program. The scenarios having $28.50 and $34.10 per barrel starting prices are offered to show what could happen if OPEC regained its former level of market power as a result of sharply curtailed domestic production, significant increases in demand, and increased dependence on imports. Even MMS' higher prices are conservative compared to DRI in later years.

TABLE 12A

COMPARISON OF 1984 PRICE SCENARIOS AND 1987 PRICES ACTUALLY REPRESENTED

| 1984 Price Scenarios per Barrel | 1987 Price Used In Pacific/Alaska | 1987 Price Used In Atlantic/GOM |
|---|---|---|
| $9.00 | $9.45 | $11.60 |
| $14.00 | $15.05 | $17.25 |
| $19.00 | $20.65 | $22.85 |
| $24.00 | $26.30 | $28.50 |
| $29.00 | $31.90 | $34.10 |
| $34.00 | $37.50 | $39.75 |

TABLE 12B

FOUR OIL PRICE SCENARIOS EAST AND GULF COAST CRUDE MARKETS*
(Current Dollars)

| Starting Price: | 1987 | 1990 | 1995 | 2000 | 2005 | 2010 |
|---|---|---|---|---|---|---|
| | 34.10 | 40.61 | 54.35 | 72.73 | 97.33 | 130.25 |
| | 28.50 | 33.94 | 45.42 | 60.79 | 81.35 | 108.86 |
| | 22.85 | 27.21 | 36.42 | 48.74 | 65.22 | 87.28 |
| | 17.25 | 20.54 | 27.49 | 36.79 | 49.24 | 65.89 |

* Prices reflect transportation and crude oil quality adjustments for the east and gulf coast markets.

TABLE 12C

WORLD CRUDE OIL PRICE FORECASTS
(Current Dollars)

| Source* | 1987 | 1990 | 1995 | 2000 | 2010 | Average Annual Price Increase to 1995 |
|---|---|---|---|---|---|---|
| DRI | 15.80 | 20.00 | 32.50 | 62.50 | 150.00 | 9.4 |
| Wharton | 15.86 | 23.19 | 33.74 | | | 9.6 |
| Chase | 17.65 | 20.90 | 26.04 | | | 6.8 |

* Data Resources, Inc., (DRI), Energy Review, June 1986.
Wharton, World Economic Outlook, May 1986.
Chase Econometrics, Long-Term Macro Solution, June 1986.

G-34



4. Discount Rates

In computing expected net economic values, real (annual) private and public discount rates of 6 and 8 percent were used. The private (after-tax) rate influences lessees' decisions on the magnitude and timing of exploration and development. A recent study on rates of return for OCS investments suggests that private after-tax real rates of return have been around 7 percent historically (W. J. Mead, P. E. Sorensen, et al., Additional Studies of Competition and Performance in OCS Oil and Gas Sales, 1954-1975, Final Report, USGS Contract No. 14-08-0001-18678, November 30, 1980).

Although the precise specification of the "correct" public discount rate is impossible, rates of 6- to 8-percent were used in our analyses. The 8 percent rate has been employed consistently in OCS program and tract specific evaluations since the late 1970's. Further, the 6- to 8-percent public discount rates:

1. Represent a reasonable range of returns to private investment and consumption spending.

2. Reflect the fact that OCS offerings do not mandate the replacement of private investment decisions with public selections.

3. Recognize that many public benefits of the OCS usually are unmeasured.

4. Reflect the reduction in both direct and indirect Federal cost of raising funds resulting from the substantial revenues generated by the OCS program.

5. Represent the strong correspondence between public and private preferences in the pace of OCS leasing.

Table 13 lists net economic values per barrel (for leasable resources) and indicates their sensitivity to different discount rates and annual rates of oil price change. The table clearly indicates that higher net economic values per barrel are associated with lower discount rates. Using the base case (8 percent discount rate, 1 real price percent growth) assumptions for comparison, a 6 percent discount rate with 1 percent real growth would result in net economic values per barrel that are about 40 percent higher in the GOM and the Pacific, 70 percent higher in the Atlantic, and 90 percent higher in Alaska.

5. Tax Parameters

After the economic analysis conducted for this report was completed, the President signed into law the Tax Reform Act of 1986. The major features of the new law, as they relate to the oil and gas industry, are a reduction in the marginal tax rate from 46 to 34 percent; repeal of the investment tax credit; lengthening of the average time required to depreciate capital items; and, a limitation on the use of expensing intangible drilling costs.

A preliminary assessment of these effects on selected positively valued UCS prospects suggests that typical prospects will have their ATNPV increased by 10 to 20 percent. However, partly because tax payments are a private but not a public cost, there is no direct effect on the measures of NEV for the existing set of leasable prospects previously identified in this study.

Nevertheless, the new tax law will produce an indirect effect on leasable resources by encouraging more production from a given field, thereby increasing economically recoverable resources and hence aggregate NEV's. Also, the higher private return from the lower tax rate will move some prospects from a marginally leasable to leasable category, thereby further increasing aggregate NEV's.

But, these increases in NEV are expected to be relatively small. This is the case in part because any additional production is stimulated from marginally economic fields or from marginally valued resources produced on a given field, generally near the end of its productive life. The overall effects from the new tax parameters therefore are likely to be a slight increase in leasable resources and total NEV's, without any changes occurring in the ranking of planning areas based on these economic measures.



## TABLE 13

SENSITIVITY OF NET ECONOMIC VALUE PER BARREL (MID - 87) FOR LEASABLE RESOURCES TO DISCOUNT RATE AND ANNUAL OIL PRICE GROWTH RATE ASSUMPTIONS

| Price = | $14/BOE | | | $29/BOE | | | $14/BOE | | | $29/BOE | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Discount Rate= | 8% | | | 8% | | | 6% | | | 6% | | |
| Price Growth = | 0% | 1% | 2% | 0% | 1% | 2% | 0% | 1% | 2% | 0% | 1% | 2% |
| PLANNING AREA | | | | | | | | | | | | |
| Central Gulf of Mexico | 1.53 | 2.40 | 3.41 | 5.89 | 7.60 | 9.58 | 2.48 | 3.66 | 5.03 | 8.43 | 10.73 | 13.40 |
| Western Gulf of Mexico | 1.03 | 1.90 | 2.91 | 5.09 | 6.80 | 8.78 | 1.87 | 3.05 | 4.41 | 7.45 | 9.75 | 12.42 |
| Southern California | 1.82 | 2.60 | 3.50 | 4.46 | 6.10 | 7.98 | 2.70 | 3.73 | 4.92 | 6.45 | 8.62 | 11.11 |
| Navarin Basin | -.25* | .49* | 1.34* | 1.08 | 2.60 | 4.40 | .15* | 1.16* | 2.37* | 2.35 | 4.47 | 6.98 |
| South Atlantic | .33 | 1.50 | 2.90 | 1.81 | 4.10 | 6.84 | 1.40 | 3.07 | 5.07 | 4.19 | 7.46 | 11.36 |
| Middle Atlantic | -.20 | 1.00 | 2.42 | 1.55 | 3.90 | 6.68 | .66 | 2.34 | 4.33 | 3.72 | 7.01 | 10.90 |
| Eastern Gulf of Mexico | .13 | 1.06 | 2.01 | 3.39 | 5.10 | 7.08 | .65 | 1.83 | 3.19 | 5.21 | 7.51 | 10.18 |
| Chukchi Sea | [-2.28] | [-1.66] | [-.89] | .21 | 1.50 | 3.12 | [-2.93] | [-1.96] | [-.75] | .97 | 2.99 | 5.52 |
| Beaufort Sea | [-1.78] | [-1.13] | [-.32] | .84 | 2.20 | 3.90 | [-2.20] | [-1.19] | [+.09] | 1.91 | 4.03 | 6.69 |
| Central California | 1.23 | 2.00 | 2.88 | 5.28 | 6.90 | 8.74 | 1.87 | 2.88 | 4.02 | 7.25 | 9.36 | 11.75 |
| Northern California | 1.83 | 2.60 | 3.48 | 4.94 | 6.60 | 8.49 | 2.61 | 3.61 | 4.76 | 7.00 | 9.15 | 11.60 |
| St. George Basin | [-2.66] | [-1.93] | [-1.07] | 1.38 | 2.90 | 4.70 | [-2.92] | [-1.91] | [-.71] | 2.73 | 4.85 | 7.37 |
| North Atlantic | .50 | 1.70 | 3.12 | 1.15 | 3.50 | 6.28 | 1.53 | 3.22 | 5.21 | 3.22 | 6.51 | 10.40 |
| Wash/Oregon | 1.82 | 2.60 | 3.48 | 6.47 | 8.10 | 9.93 | 2.59 | 3.56 | 4.70 | 8.62 | 10.70 | 13.03 |
| Gulf of Alaska | [-3.49] | [-2.80] | [-1.96] | -.24 | 1.20 | 2.96 | [-4.31] | [-3.29] | [-2.05] | .49 | 2.63 | 5.24 |
| North Aleutian Basin | [-3.39] | [-2.70] | [-1.86] | -.14 | 1.30 | 3.06 | [-4.10] | [-3.16] | [-1.91] | .63 | 2.76 | 5.37 |
| Norton Basin | [-3.86] | [-3.13] | [-2.27] | .18 | 1.70 | 3.50 | [-4.45] | [-3.44] | [-2.24] | 1.20 | 3.32 | 5.84 |
| Kodiak | [-2.53] | [-1.84] | [-1.00] | .72* | 2.16* | 3.92* | [-3.02] | [-2.00] | [-.75] | 1.79* | 3.92* | 6.53* |
| Florida Straits | .05* | 1.30* | 2.76* | 3.06 | 5.50 | 8.36 | 1.05* | 2.77* | 4.78* | 5.69 | 9.04 | 12.97 |
| Hope Basin | [-3.61] | [-2.85] | [-1.94] | .39* | 1.98* | 3.88* | [-4.23] | [-3.14] | [-1.84] | 1.48* | 3.75* | 6.47* |
| Shumagin | [-3.14] | [-2.31] | [-1.29] | .78* | 2.52* | 4.65* | [-3.77] | [-2.53] | [-1.03] | 2.04* | 4.62* | 7.77* |
| Cook Inlet | [-2.56] | [-1.87] | [-1.03] | .69* | 2.13* | 3.89* | [-3.06] | [-2.04] | [-.79] | 1.75* | 3.88* | 6.49* |

Notes:

Numbers in brackets indicate values that would be obtained using $29 per barrel field size.

Numbers followed by asterisks indicate values that would be obtained using field size with After-Tax Net Present Value equal to zero.

# VIII. Alternative Energy Sources

## A. Background

The U.S. economy has passed the peak of its reliance on domestic oil and gas resources. This general assessment is based on examination of historical data on energy production and consumption and on energy projections through the year 2010 (see Table F-14) prepared by the Department of Energy (DOE) as the Reference-Case Projections for the 1985 National Energy Policy Plan (NEPP).

Oil and gas consumption began to substantially supplant coal about 1920, although this process was underway a few years earlier, a trend generally corresponding to expanding use of the automobile. Based on data from the Department of the Interior (DOI) publication Energy Perspectives 2, oil and gas combined edged past coal in total U.S. energy consumption in 1947, with 15.8 quads of coal consumption to 15.9 quads of oil and gas consumption. Oil alone surpassed coal in 1950, with 12.9 quads of coal consumption to 13.5 quads of oil consumption. (The term quads represents one quadrillion British thermal units of heat energy and is approximately equal to 172.4 million barrels of oil. Quads are the generally accepted measure for comparing large volumes of energy from differing energy sources.)

In the late 1960's, close observers of energy issues in the Federal Government and other centers of interest began to try to call attention to a likely early peaking of ability to supply oil from domestic sources. Liquid hydrocarbons produced from Federal onshore leases peaked at 229.5 million barrels in 1969. Total domestic proved reserves peaked in 1970. Liquid hydrocarbons produced from Federal leases on the Outer Continental Shelf (OCS) peaked at 455.5 million barrels in 1971.

At this point, oil imports increased very rapidly to fill the gap between declining domestic production and increasing energy supply requirements. Oil imports peaked at a rate of about 8.6 million barrels per day in 1977. Total oil supplied to the U.S. economy also peaked in 1977 at 18.5 million barrels per day, a level representing about 75 percent of total energy consumption.

Two major shocks to the world oil market focused public attention on oil supply issues. The 1973-74 Arab oil embargo cut off Middle Eastern oil sources from unrestricted trade in world oil markets and resulted in escalation of oil prices from a pre-embargo world price of $7.74 per barrel in 1970 to a post-embargo price of $24.40 in 1975. The world oil market received its second major jolt during the 1979-80 Iranian revolution which once again reduced oil supply levels and accelerated prices to a 1980 world price of $42.36 per barrel.

In response to these events, the U.S. and the rest of the world instituted a wide variety of measures to conserve energy and to find alternative sources of supply. The overall success for these measures was reflected by a decline in the world oil price to about $29 per barrel in 1984.

The inability of the Organization of Petroleum Exporting Countries (OPEC) to secure the cooperation of its members to reduce production and halt this price slide contributed to decisions of certain OPEC members to substantially increase production. The combination of lower demand initially brought about as a response to high OPEC pricing and the decisions to increase rates of production combined



TABLE 14: REFERENCE CASE--PRIMARY ENERGY SUPPLIED TO THE U.S. ECONOMY
(QUADS)

| | INDIGENOUS ENERGY PRODUCTION | | | | | | NET IMPORTS[a)] | | | | | ADJUSTMENTS[b)] | | | | | PRIMARY ENERGY SUPPLIED TO U.S. ECONOMY |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | STOCK CHANGES | | | | | |
| YEAR | OIL | GAS | COAL | NUCLEAR | RENEW-ABLE | TOTAL | OIL | GAS | COAL | OTHER[c)] | TOTAL | OIL | GAS | COAL | OTHER[d)] | TOTAL | TOTAL |
| HIST. | | | | | | | | | | | | | | | | | |
| 1960 | 16.4 | 12.7 | 11.1 | - - | 3.0 | 43.2 | 3.6 | 0.1 | -1.0 | - - | 2.7 | 0.1 | -0.3 | 0.1 | -0.3 | -0.4 | 45.5 |
| 1965 | 18.4 | 15.8 | 13.4 | - - | 3.4 | 51.0 | 5.0 | 0.4 | -1.4 | - - | 4.0 | - - | -0.2 | - - | -0.5 | -0.7 | 54.3 |
| 1970 | 22.9 | 21.7 | 15.0 | 0.2 | 4.1 | 63.9 | 6.9 | 0.8 | -1.9 | - - | 5.8 | -0.2 | -0.4 | -0.3 | -0.5 | -1.4 | 68.3 |
| 1975 | 20.1 | 19.6 | 15.2 | 1.9 | 4.8 | 61.6 | 12.5 | 0.9 | -1.8 | 0.1 | 11.7 | -0.3 | -0.4 | -0.7 | 0.3 | -1.1 | 72.2 |
| 1980 | 20.5 | 19.9 | 18.6 | 2.7 | 5.3 | 67.0 | 13.5 | 1.0 | -2.4 | 0.1 | 12.2 | -0.3 | - - | -0.5 | - - | -0.9 | 78.3 |
| ESTI. | | | | | | | | | | | | | | | | | |
| 1984 | 21.2 | 17.8 | 19.7 | 3.6 | 6.4 | 68.7 | 9.9 | 0.8 | -2.1 | 0.1 | 8.8 | -0.6 | -0.2 | -0.6 | 0.5 | -0.9 | 76.6 |
| PROJ. | | | | | | | | | | | | | | | | | |
| 1990 | 21.2 | 18.0 | 23.2 | 6.1 | 6.8 | 75.4 | 12.5 | 1.4 | -2.2 | 0.2 | 11.9 | - - | - - | - - | - - | - - | 87.3 |
| 1995 | 19.3 | 18.0 | 26.0 | 6.5 | 8.5 | 78.3 | 14.4 | 2.4 | -2.4 | 0.3 | 14.7 | - - | - - | - - | - - | - - | 93.1 |
| 2000 | 18.3 | 16.6 | 29.6 | 6.9 | 10.3 | 81.8 | 15.8 | 3.4 | -2.7 | 0.3 | 16.8 | - - | - - | - - | - - | - - | 98.6 |
| 2005 | 17.4 | 15.5 | 34.7 | 7.3 | 12.3 | 87.2 | 16.2 | 3.8 | -3.3 | 0.3 | 17.0 | - - | - - | - - | - - | - - | 104.2 |
| 2010 | 15.6 | 15.3 | 39.7 | 8.7 | 14.5 | 93.7 | 17.6 | 3.0 | -3.8 | 0.3 | 17.1 | - - | - - | - - | - - | - - | 110.8 |

PHYSICAL UNITS

| YEAR | MILLION BPD | TRILL'N CU. FT. | MILLION TONS | BILLION KWH | MILLION BDOE | MILLION BDOE | MILLION BPD | TRILL'N CU. FT. | MILLION TONS | MILLION BDOE | MILLION BDOE | MILLION BPD | TRILL'N CU. FT. | MILLION TONS | MILLION BDOE | MILLION BDOE | MILLION BDOE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ESTI. | | | | | | | | | | | | | | | | | |
| 1984 | 10.5 | 17.4 | 890 | 335 | 3.0 | 32.4 | 4.7 | 0.8 | -80 | 0.1 | 4.2 | -0.3 | -0.2 | -29 | 0.2 | -0.4 | 36.2 |
| PROJ. | | | | | | | | | | | | | | | | | |
| 1990 | 10.5 | 17.7 | 1058 | 570 | 3.2 | 35.6 | 5.9 | 1.4 | -83 | 0.1 | 5.6 | - - | - - | - - | - - | - - | 41.2 |
| 1995 | 9.5 | 17.7 | 1188 | 613 | 4.0 | 37.0 | 6.8 | 2.4 | -92 | 0.1 | 7.0 | - - | - - | - - | - - | - - | 44.0 |
| 2000 | 9.0 | 16.3 | 1353 | 652 | 4.9 | 38.6 | 7.4 | 3.4 | -104 | 0.1 | 7.9 | - - | - - | - - | - - | - - | 46.6 |
| 2005 | 8.4 | 15.2 | 1585 | 689 | 5.8 | 41.2 | 7.6 | 3.8 | -125 | 0.1 | 8.0 | - - | - - | - - | - - | - - | 49.2 |
| 2010 | 7.6 | 15.0 | 1806 | 819 | 6.8 | 44.3 | 8.3 | 2.9 | -145 | 0.1 | 8.1 | - - | - - | - - | - - | - - | 52.3 |

a) Including Strategic Petroleum Reserve.
b) Negative numbers indicate a reduction in energy supplied and positive numbers indicate an increase in energy supplied to the economy.
c) Includes small amounts of coal coke and electricity.
d) A balancing item. Includes unaccounted for oil, gas and coal private stock changes, losses, gains, miscellaneous blending componets, unaccounted for supply and anthracite shipped overseas to U.S. Armed Forces.

during 1986 to produce very rapid declines in oil prices to levels which were inconceivable only months before. During 1986, world oil prices on the spot markets frequently fell to levels well below $10 per barrel.

These recent events have resulted in a general lowering of projected future prices. Nonetheless, the combination of increasing world demand, limited world oil and gas resources, and continuing efforts by OPEC members to reach agreements on production quotas is expected to bring about new rounds of oil price increases. The DOE reference case assumes world prices of $22.89 in 1990, $29.79 in 1985, $36.75 in 2000, and $56.77 in 2010.

The reference case represents only one assessment of possible future energy supply conditions. The NEPP also includes alternative scenarios based on different assumptions concerning rates of economic growth, U.S. success in finding and developing domestic energy resources, and levels of efficiency achieved in the use of energy resources. The projections of energy prices and supply responses assume relatively regular responses to generalized political, social, and economic conditions. Real prices and supplies respond to various unpredictable events and are likely to fluctuate both above and below the levels projected in the scenario which most nearly coincides to developing actual conditions. Nonetheless, the NEPP and other studies suggest certain converging views about future trends. These have been stated as follows in the NEPP.

- Although the outlook for future world oil prices1/ is highly uncertain, most analysts now agree that world oil prices probably will fall or remain constant in real terms until the late 1980's, barring a significant oil supply disruption. Beyond 1990, the outlook becomes increasingly uncertain.

- The oil price increases of 1973-74 and 1979-81 set into motion powerful energy conservation forces that are likely to continue, especially in terms of oil use. Even though prices are temporarily declining, the long-term expectation is for increasing prices. Energy conservation has become as important as various sources of energy supply in determining the future evolution of the United States and world energy situations. Therefore, more attention should be given to energy conservation trends in future energy projections.

- Oil price increases also provided incentives for development of energy resources other than oil.

- The recent decline in world oil prices has added a new dimension to the uncertainty about future market behavior. Now, investment planners must be concerned about the potential for future price breaks as well as price increases.

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1/"World oil price" is defined as the average cost to U.S. refiners, including transportation and fees, of imported crude oil. This average reflects differences in quality among the various imported crudes purchased by U.S. refiners.



- Under all but extreme assumptions, the United States and most of the rest of the world will remain net oil importers with OPEC a major source of supply for at least the next 20 years.

B. Oil and Gas

Subject to limitations of availability and price, oil and natural gas are projected to remain the fuels of choice in the U.S. economy. The rates of use in alternative fuels will be largely determined by factors such as success in finding new domestic oil and gas resources, political events affecting oil supplies from one or more of the major exporting nations, or technological breakthroughs related to costs of any of the major alternative energy sources.

Production from domestic oil reserves has exceeded additions for about the last 15 years causing total proved reserves also to decline. The DOE did estimate an increase of 2.6 percent or about 711 millions barrels in U.S. oil reserves in 1984. This was the first increase in reserves since 1970 when oil was discovered in Alaska's Prudhoe Bay. However, this increase is in part misleading as the 1984 estimate includes substantial credit for anticipated application of enhanced oil recovery techniques in existing fields. It is especially important to recongize that enhanced recovery techniques are expensive and their application will be discouraged by recent and projected declines in oil prices. In analyzing possible increases in reserves through new domestic oil and gas discoveries, it is necessary to acknowledge that the United States, especially onshore, is a mature oil province. Future domestic oil production will be heavily dependent upon small fields, deep offshore areas, hostile arctic areas, and advanced production technologies. All of these factors will require the encouragement of higher oil prices and will be technologically challenging.

A July 1985 DOE study titled <u>Replacement Costs of Domestic Crude Oil</u> is most useful in understanding future domestic oil prospects and limitations. Even with additional drilling and further development, this study projects that the expected depletion rate for already discovered fields would result in production falling by more than half by 2000 if there were no discoveries of new domestic oil fields. New discoveries are expected, of course, but will not be easy. In the period 1980 to 1982, there were no new field discoveries of over 50 million barrels of oil reserves, 79 discoveries of significant size greater than 1 million barrels, and 2,075 from a total of 2,154 discoveries were small fields of less than 1 million barrels of oil. The best prospects for finding really large fields are where we have looked least to date, that is in frontier areas offshore and in the arctic.

Even though the United States has very large coal reserves and other energy sources, there is no real prospect for avoiding heavy continued reliance on oil and gas resources. This fact is quickly established by analyzing energy requirements by different categories of use and by focusing particularly on transportation. The transportation sector relies almost entirely on petroleum and offers little flexibility in choice of fuels. The Nation's cars, trucks, and airplanes have few prospects for reducing their dependence upon gasoline, diesel fuel, and jet fuel.

The NEPP reference case projections by user sector for transportation indicate petroleum liquids requirements of 18.5 quads in 1990, 18.6 quads in 1995, 19.3 quads in 2000, and 20.3 quads in 2010. At this rate, the transportation sector alone will exceed total projected domestic petroleum production by about 1997. To put it another way, in only 10 years the United States would utilize the oil equivalent of its domestic production and begin to require a low level of imports even if oil were used for nothing else but meeting transportation needs. It is necessary to only briefly recall what is known about the rate of decline projected for known reserves and the prevalence of small fields in the known reserves to understand that the Unites States will remain heavily dependent upon the discovery and development of new offshore fields regardless of the prospects for development of other domestic energy sources.

The NEPP projections assume continued increases in costs of production and continued declines in overall domestic oil production. The net results of various behavior assumptions is long term decline in U.S. domestic oil production over the projection period from 21.1 quads in 1984 to 15.6 quads in 2010.

Unconventional gas production is expected to respond to rising prices and to begin to offset natural reserve declines in the early 1900's. Overall, natural gas is projected to remain at about 18.0 quads through 1995 and to then begin a long term decline to the 2010 projection of 15.3 quads.

The DOE also prepared a special analysis of the effects of sharply lower world oil prices. Relative to the projections of the NEPP reference case, major conclusions are that:

- Lower oil prices will not be sustained permanently.
- The lower oil prices fall, the sooner the subsequent price recovery will begin.
- Lower prices will stimulate both growth in the domestic economy and increased consumption of energy resources.
- The primary shifts in fuels will involve reduced domestic oil production and increased oil imports.

The longer term analysis of prices is important from purposes of the 5-year program. Leases are not likely to enter production for a period of 8 to 10 years following their acquisition. Industry interest in acquiring leases and undertaking exploration expenditures are based largely on price expectations which correspond to the anticipated period of production for a specific lease. DOE concluded that ". . . by 1995 the 1986 crude oil price will make almost no difference because prices 10 years from now will be based primarily on fundamental longer-term market forces, rather than on current market transients."

The DOE assessment of effects of lower prices was specifically based on assumed oil prices $10 per barrel below the level assumed in the *Annual Energy Outlook 1985* base case. Specific prices assumed for this analysis were a 1986 price of $13 per barrel and a rise to $20 per barrel by 1995. Overall, the analysis suggests that a price of $20 per barrel is not likely to be sustained to 1995 due to demand pressures which result at this price. At $20 per barrel, world demand is likely to exceed production capacity. A price of about $25 per barrel is indicated as necessary in 1995 to restore equilibrium to world oil markets.



Under the stipulated price assumptions, the analysis projects that domestic oil production will decline by about 900 thousand barrels per day in 1990 and 1.5 million barrels per day in 1995. The corresponding increases in oil imports are 1.6 million barrels per day in 1990 and 3.2 million barrels per day in 1995. The net increases are the result of increased demand in response to the effects of economic growth stimulated by lower world prices. This strong response of imported oil offsetting reduced domestic production at a more than 2 to 1 ratio by 1995 reflects a strong oil preference in the domestic energy marketplace. The effects of lower prices are compounded over time as lower prices result in a slowdown in exploration and development at the same time that continued production from existing wells results in depletion of developed reserves. The effects of cheap foreign oil also include reduced incentives to invest in other energy sources and technologies.

The effects of lower world oil prices are judged to be most significant for oil and less significant for other energy resources. Natural gas use is expected to decline slightly by 1995 as reduced gas demand resulting from increased oil competition is expected to exceed the stimulus effects of greater economic growth. Levels of gas imports are projected to be affected very little by oil price declines. Impacts of lower oil prices on natural gas are expected to result in a 1995 decline in domestic gas production from about 17.1 trillion cubic feet to about 15.9 trillion cubic feet.

Coal market conditions and consumption effects are relatively small. Lower oil prices again have two types of effects. The competition from lower priced oil creates a lower demand for coal and is termed by DOE as the "substitution effect." The increase in demand caused by more rapid economic growth is termed the "income effect." Overall, the analysis suggests an edge to the income effect and a modest increase in coal production. The impacts of lower oil prices are expected to result in an increase in 1995 production from 1,116 million short tons to 1,129 million short tons.

Effects of lower world oil prices on renewable and other basic energy sources did not receive specific evaluation in the DOE analysis. Overall, effects are likely to be small. The use of renewables most likely will decline in the short run but may be affected less in the long run as oil prices return to higher levels and technological advances enhance the attractiveness of renewable energy sources.

In general, the current price situation has been induced by production decisions of a few countries with current excess oil production capacities. The trend is expected to be relatively short term, to result in reduced domestic oil production and increased oil imports, and to have relatively lower effects on other energy sources either in terms of price or quantities of resources produced and delivered to the market place.

## C. Coal

Coal is projected by the NEPP to increase in production more than any other fuel--from 19.7 quads in 1984 to 39.7 quads in 2010. Major factors contributing to growth in coal production are expected to be growth in U.S. coal exports as well as increasing coal utilization in the U.S. economy. The chief uncertainty is to what extent costs associated with the use of coal will reduce its capacity to compete in the marketplace. As already noted, the special analysis of sharply lower oil prices indicates a slight edge to the "income effect" of economic growth and a modest increase in coal production over the NEPP Reference Case. Despite difficulties, coal is expected to be used cleanly enough to maintain environmental quality standards. The NEPP indicates that coal is the fuel most affected by changes in domestic energy market conditions. In the year 2000 for example, coal accounts for about 65 percent of the change in domestic energy supply in the high growth scenario and 64 percent of the change in the low growth scenario when both are compared to the reference case.

Existing coal mines and coal transportation facilities are estimated to have the capacity to supply about 1.0 to 1.2 billion tons of coal per year (100-300 million tons greater than estimated 1984 production). At this level, producers could supply the reference case coal production target through 1990 with little or no expansion of capacity. Over the longer term, as oil and gas resources are expected to increasingly fall short of market requirements, additional coal production capacity will be needed. Reference case energy supply projections anticipate coal supplied energy at 23.2 quads in 1990, 26.0 quads in 1995, 29.6 quads in 2000, and 39.7 quads in 2010. The levels of production reached may vary widely in response to actual market conditions.

Coal is not expected to provide for any significant offset of oil used for liquid fuels. Coal is the major fuel for energy transformation, with the two major sectors of transformation being electric utilities and synthetic fuels. The NEPP estimates that even by 2010, coal used for synthetic fuels production will account for only about 2 percent of the energy applied to energy transformation.

## D. Nuclear

Nuclear power projections reflect slowdowns in plant construction, cancellation of plants under construction, and several years with no new plant orders. There is recognized to be a high degree of uncertainty regarding orders and construction times for new plants after 1990. The Administration has a variety of nuclear-related policy proposals directed toward Congressional action to restore stability to the nuclear powerplant licensing process. Regulatory reform proposals and public opinion on nuclear power are variables which complicate nuclear power projections beyond normal assessment of response to supply/demand relationships. For purposes of comparison with other energy sources, reference case projections expressed in quads are 6.1 quads in 1990, 6.5 quads in 1995, 6.9 quads in 2000, and 8.7 quads in 2010.



## E. Renewables and Geothermal

Rapid escalation in oil and gas prices set in motion powerful energy conservation forces as well as accelerating the search for alternative fuel sources. Given energy self-sufficiency problems in continued use of oil and gas and environmental problems which are widely recognized in coal and nuclear energy sources, a high level of public interest has focused on renewable energy sources.

Existing central-electric renewable energy production is primarily from hydroelectric power. The U.S. is the world's leading generator of hydroelectric power. About 13.3 percent of total U.S. electricity generated in 1984 was from hydroelectric sources. Large scale hydroelectric potential is limited by the availability of appropriate sites. Most new capacity is expected to come from retrofitting existing dams with new, more efficient equipment.

Geothermal energy is combined with hydroelectric power in the DOE analysis. Current utilization of the earth's internal heat is primarily through generation of electricity from natural steam at the Geysers site in northern California. In the future, other potential geothermal sources and technologies are likely to increase electric power generation. Other applications of geothermal energy such as space heating and industrial process heat also will increase.

The next form of energy expected to make a significant contribution to renewable energy use is wood. This use is limited, however, by wood availability and transportation costs. Wood utilization, therefore, is likely to be mostly in residential space heating and in the wood products industry which utilizes wood waste as a source of fuel.

Projected price increases for oil and gas in the 1990's are expected to stimulate large scale development of wind, photovoltaic, and solar central electric technologies. These technologies also offer high adaptability to dispersed use.

Renewable technologies are especially subject to uncertainties about future technological and economic factors. Overall, renewables are expected to advance from modest current use to a significant energy supply source by 2000. Estimates of future production for various renewable sources are summarized in Table F-15. The overall renewable/geothermal domestic energy projection estimates of the reference case indicate these sources increasing from 6.4 quads in 1984 to 6.8 quads in 1990, 8.5 quads in 1995, 10.3 quads in 2000, and 14.5 quads in 2010.

## F. Summary

Oil imports which went up in 1984 for the first time since 1977 are projected to continue to increase. Crude oil and refined petroleum imports are projected to increase from 9.9 quads in 1984 to 12.5 quads in 1990, 14.4 quads in 1995, 15.8 quads in 2000 and 17.6 quads in 2010. OCS leasing is not expected to back out these levels of imports, but hopefully will allow the U.S. to avoid rapidly accelerated dependence which was typical of the early 1970's and which seriously threatened national security and healthy economic growth. While short-

TABLE 15 : REFERENCE CASE--U.S. RENEWABLE ENERGY PRODUCTION AND CONSUMPTION
(QUADS)

| | INDIGENOUS PRODUCTION | | | | | | | | | | | | | | | TRANSFORMATION | | RENEWABLES USED BY FINAL CONSUMERS |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | CENTRAL ELECTRICITY INPUTS | | | | | | DISPERSED | | | | | | | | PRIMARY RENEWABLES | | | |
| | | | | | | | BIOMASS | | ACTIVE SOLAR HEATING/COOLING | AGRIC. INDUST. PROCESS HEAT | GEOTHERMAL | PHOTOVOLTAIC | WIND | TOTAL | | TO CENTRAL ELECTRICITY | TO ALCOHOL FUELS[b] | |
| YEAR | HYDRO/GEOTH. | WOOD | SOLAR THERMAL | PHOTOVOLTAIC | WIND | TOTAL | WOOD | OTHER[a] | | | | | | | TOTAL | | | TOTAL |
| HIST. | | | | | | | | | | | | | | | | | | |
| 1960 | 1.7 | - - | - - | - - | - - | 1.7 | 1.3 | - - | - - | - - | - - | - - | - - | 1.3 | 3.0 | -1.7 | - - | 1.3 |
| 1965 | 2.1 | - - | - - | - - | - - | 2.1 | 1.3 | - - | - - | - - | - - | - - | - - | 1.3 | 3.4 | -2.1 | - - | 1.3 |
| 1970 | 2.7 | - - | - - | - - | - - | 2.7 | 1.4 | - - | - - | - - | - - | - - | - - | 1.4 | 4.1 | -2.7 | - - | 1.4 |
| 1975 | 3.2 | - - | - - | - - | - - | 3.2 | 1.5 | - - | - - | - - | - - | - - | - - | 1.6 | 4.8 | -3.2 | - - | 1.6 |
| 1980 | 3.0 | - - | - - | - - | - - | 3.0 | 2.2 | - - | - - | - - | - - | - - | - - | 2.3 | 5.3 | -3.0 | - - | 2.3 |
| ESTI. 1984 | 3.6 | - - | - - | - - | - - | 3.6 | 2.7 | 0.1 | 0.1 | - - | - - | - - | - - | 2.8 | 6.4 | -3.6 | - - | 2.8 |
| PROJ. | | | | | | | | | | | | | | | | | | |
| 1990 | 3.5 | - - | - - | - - | - - | 3.5 | 2.9 | 0.2 | 0.1 | 0.1 | 0.1 | - - | - - | 3.3 | 6.8 | -3.5 | -0.1 | 3.3 |
| 1995 | 4.0 | 0.2 | - - | - - | 0.3 | 4.5 | 3.2 | 0.3 | 0.1 | 0.2 | 0.1 | - - | 0.1 | 4.0 | 8.5 | -4.5 | -0.2 | 4.0 |
| 2000 | 4.5 | 0.3 | - - | - - | 0.7 | 5.5 | 3.6 | 0.5 | 0.1 | 0.3 | 0.2 | - - | 0.1 | 4.8 | 10.3 | -5.5 | -0.3 | 4.8 |
| 2005 | 4.8 | 0.3 | - - | 0.2 | 1.1 | 6.4 | 3.8 | 0.9 | 0.1 | 0.4 | 0.3 | 0.2 | 0.1 | 5.8 | 12.3 | -6.4 | -0.6 | 5.8 |
| 2010 | 5.1 | 0.3 | 0.1 | 0.7 | 1.4 | 7.5 | 3.9 | 1.3 | 0.2 | 0.5 | 0.5 | 0.5 | 0.2 | 6.9 | 14.5 | -7.5 | -0.9 | 6.9 |

PHYSICAL UNITS

| YEAR | MILLION BDOE | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ESTI. 1984 | 1.7 | - - | - - | - - | - - | 1.7 | 1.3 | - - | - - | - - | - - | - - | - - | 1.3 | 3.0 | -1.7 | - - | 1.3 |
| PROJ. | | | | | | | | | | | | | | | | | | |
| 1990 | 1.7 | - - | - - | - - | - - | 1.7 | 1.4 | 0.1 | - - | 0.1 | - - | - - | - - | 1.6 | 3.2 | -1.7 | -0.1 | 1.6 |
| 1995 | 1.9 | 0.1 | - - | - - | 0.1 | 2.1 | 1.5 | 0.2 | - - | 0.1 | 0.1 | - - | - - | 1.9 | 4.0 | -2.1 | -0.1 | 1.9 |
| 2000 | 2.1 | 0.1 | - - | - - | 0.3 | 2.6 | 1.7 | 0.2 | - - | 0.1 | 0.1 | - - | - - | 2.3 | 4.9 | -2.6 | -0.1 | 2.3 |
| 2005 | 2.3 | 0.1 | - - | 0.1 | 0.5 | 3.0 | 1.8 | 0.4 | 0.1 | 0.2 | 0.2 | 0.1 | - - | 2.8 | 5.8 | -3.0 | -0.3 | 2.8 |
| 2010 | 2.4 | 0.1 | - - | 0.3 | 0.7 | 3.6 | 1.9 | 0.6 | 0.1 | 0.2 | 0.2 | 0.2 | 0.1 | 3.3 | 6.8 | -3.6 | -0.4 | 3.3 |

a) Includes sewer and landfill gas, municipal and agricultural waste, and biomass alcohol inputs.
b) Included in renewables used by final consumers.





term responses to lower oil prices indicate a relative increase oil imports, the longer term view indicates the need to continue the concerted effort initiated following the 1973 oil embargo to use energy more efficiently, to find new domestic oil and gas resources, to diversify the sources of oil imports, and to learn how to best utilize alternative energy sources.

# APPENDIX G

## Estimates of Potential Social Costs of Developing the Oil and Gas Resources in Each OCS Planning Area

## CONTENTS

LIST OF TABLES

# I. Introduction, Summary and Conclusions

## A. Background, Purpose, and Scope

Section 18(a)(3) of the Outer Continental Shelf Lands Act (OCSLA) provides that the timing and location of individual OCS lease sales be selected based on a consideration of balancing the potential for environmental damage, for the discovery of oil and gas, and for adverse impact on the coastal zone. Hence, an analysis of possible environmental damages and adverse coastal zone effects from proposed OCS oil and gas leasing is essential in order to evaluate the net social value (development benefits minus social costs) from this activity to the Nation and to each region involved with OCS hydrocarbon development.

This appendix, along with other information in the Secretarial Issue Document (SID), addresses the requirement set out in sections 18(a)(2) & (3) of the OCSLA by presenting an economic study for each planning area of the possible environmental damages and adverse impacts on the coastal zone associated with proposed and alternative five-year OCS oil and gas lease schedules. The estimates of potential damages are based on economic concepts and are given in dollar terms in order to provide a common basis for comparison with the estimated economic benefits from developing the leasable hydrocarbon resources in each OCS planning area. It is recognized, however, that some of the possible effects of OCS oil and gas leasing cannot be quantified in monetary terms, both because some issues are fundamentally not economic in nature and because the available information or the state of the art does not permit a quantitative assessment. Issues which cannot be addressed in quantitative terms will be discussed qualitatively in the environmental impact statement (EIS) accompanying the proposed five-year lease schedule as well as in Part II.B of the SID and Appendices H and I.

The purpose of this appendix is to attempt to quantify the possible costs of OCS oil and gas development to aid in the development of a lease schedule based on a consideration of a balancing of OCS benefits and costs. Given the specific program-level intent of the analysis, the economic review of the possible costs of OCS hydrocarbon development contained herein is carried out on an aggregated basis for each of the OCS planning areas. Detailed analysis of specific, intra-area resource management issues associated with a particular lease sale are beyond the scope of the present effort; these issues will be addressed in the five-year program EIS and in the EIS's and other management documents prepared in connection with individual, proposed lease sales.

## B. The Concept of Costs Used in the Analysis

### 1. Introduction

Because the term "costs" can take on different meanings depending upon how it is used, it is important to state clearly at the outset the concept of costs used throughout this appendix. Two types of costs are estimated: social costs and regional costs. All costs are evaluated in terms of their present values. For this purpose, constant dollars as of mid-1987 and a real rate of discount of 8 percent are used.1/ The primary focus of the analysis which follows is on social costs.

2. Social Costs

Social costs measure the total costs to the Nation as a whole resulting from the proposed oil and gas development in each OCS planning area. The social costs included encompass environmental or external costs and such private costs as are not considered in the analysis of development benefits presented in appendix F (e.g., oil spill cleanup and control costs and the value of lost oil). The specific costs considered in the analysis of social cost incorporate market and non-market costs and include: cleanup and control costs, direct and indirect commercial fisheries losses, tourism and recreation losses, wetlands losses, infrastructure costs, ecological costs, subsistence losses, the value of lost oil and other costs.

Excluded from social costs are transfers, secondary (or "multiplier") effects and purely private costs. Transfers are merely financial redistributions. For example, oil spill-caused losses in a community's sales tax receipts are anticipated to be offset by increases in other communities' tax revenues. Because losses by one group are counterbalanced by gains to others, no change in net social cost to the nation is involved. Similarly, oil spill damage compensation payments redistribute the burden of a spill but do not change its social cost. Secondary effects usually are omitted from the estimation of social costs unless it is unreasonable to assume full employment and mobile resources, such as might occur should an isolated commercial fishing community be affected by an oil spill. Finally, purely private losses occur when, for example, a loss in profits by the tourist industry in one location is balanced by an increase in profits at substitute sites. Because the losses in one location are offset by gains at substitute sites, no net social cost to the nation arises.

In all cost-benefit studies, the standard of comparison for assessing a policy is what would have happened in the absence of the policy. For this analysis, the with-vs.-without comparison is OCS oil and gas development vs. the alternative of imported oil. Hence, the social costs of the proposed five-year program must be measured net of the costs avoided because OCS oil and natural gas production reduces the demand for foreign oil.2/

The national focus adopted for assessing social costs is important because it is consistent with the evaluation of the benefits of OCS development at the national level. Actual measurement of the social costs of production in an OCS area, however, requires that consideration be given to the consequences of that production for other OCS areas. For example, the analysis in later sections assumes that oil produced in the Navarin Basin is shipped south to refineries by tankers, potentially resulting in oil spills off Canada and all West Coast OCS areas thereby causing potential social costs in those areas. The social costs concerned, however, are attributed to OCS oil production in the Navarin Basin since they would not have occurred in the absence of the Navarin Basin production. On the other hand, oil production in an OCS area reduces social costs in other areas by backing out imported oil and hence reducing foreign tanker spills. For example, oil produced in the Central Gulf of Mexico replaces an equivalent amount of imported oil destined for refineries in the Central Gulf of Mexico as well as other OCS areas. The reduction in imported oil means less oil will be spilled from foreign



tankers in all areas concerned. Just as costs imposed on other areas are attributable to the producing OCS area, so too, the costs avoided when imported oil and the associated oil spillage are reduced also must be assigned to the producing area if social costs are to be measured correctly from the viewpoint of the Nation as a whole.

3. Regional Costs

In addition to an analysis of social costs to the entire Nation, the equitable sharing provision of the OCSLA dictates that the distribution of the potential social costs of OCS oil and gas development also be considered. To emphasize the important difference between the potential social costs to the Nation as a whole and the potential costs estimated to be realized by residents of the producing OCS area, a second category of costs is estimated. These costs are referred to as regional costs.

Three factors determine the extent to which costs resulting from the development of hydrocarbon resources in an OCS area are borne by the residents of adjacent onshore communities and hence constitute regional costs. First, the OCSLA provides for compensation to damaged parties for OCS-related oil spills and for commercial fishing gear losses. Payment of compensation to injured parties does not change the magnitude of social costs, but it does reduce the losses to area residents by redistributing the cost from the individuals suffering losses to a broader group within society as a whole. Second, as noted above, some tanker spills resulting from OCS oil production in an area such as the Navarin Basin impose costs on other areas along tanker routes. Any such costs imposed are counted as regional costs to the residents of the adversely affected areas. (Of course, those suffering OCS-related tanker spill losses in any OCS area are eligible to receive compensation). The third factor determining the costs incurred by residents of an OCS area concerns the social costs avoided by that area when its OCS oil and natural gas production replace foreign oil which otherwise would have been delivered to that specific area.

In summary, a proper estimation of the distribution of the costs of producing OCS oil in an OCS area, therefore, must recognize (1) the importance of compensation for damages, (2) costs falling outside the producing area concerned, and (3) reduced oil spills from foreign tankers when OCS oil or natural gas backs out imports. These three factors are specifically considered in the estimate of the regional costs of producing and transporting all of an OCS area's leasable resources unleased as of mid-1987.

C. General Categories of Costs Considered

The costs examined in this appendix are those which could be incurred as a result of (1) oil spills in the marine environment, (2) physical conflicts among competing marine resource uses, and (3) other adverse coastal impacts. The third category includes (a) alteration of wetlands, (b) possible deterioration in air quality, (c) subsistence losses and (d) infrastructure costs.

A major focus of the analysis is on the costs of oil spills. Particular attention is given to the possibility of large oil spills--those over 1,000 barrels. Spills of this size from OCS production are rare. A review of OCS oil spill data in the Gulf of Mexico, which accounts for over 85 percent of recent OCS oil production, indicates that there have been no spills greater than 1,000 barrels since 1981; only three such spills have occurred from 1979 through 1984 (U.S. Dept. of Interior, 1983, p. 270; U.S. Dept. of Transportation, 1983, 1984). Nonetheless, large spills happen periodically, with potential serious damages, especially if they strike sensitive resources or reach shore within a few days, before natural weathering of the oil can reduce its harmful effects.

Small spills (those less than 1,000 barrels) also are considered in the analysis of social and regional costs. It should be noted, however, that although numerous, the total amount of oil discharged into the marine environment by small spills is relatively small compared to the total amount attributable to large spills. To illustrate, 934 small spills between 1 and 1,000 barrels constituted over 99 percent of all production platform and pipeline incidents recorded in the Gulf of Mexico from 1974 to 1983. However, these spills accounted for only about 28 percent of the volume of oil spilled during the period (U.S. Dept. of Interior, 1983, p. 270; Gail Rainey, personal communication, October 19, 1984). The average amount discharged in these small spills over the period cited was 9.4 barrels per spill.

The possible effects of drilling fluids on the marine environment are not considered in the analysis of potential costs. A recent report on this subject by the National Academy of Sciences (1983) concludes that drilling fluids discharged during exploratory operations, in general, do not pose a serious threat to the environment, although localized levels of pollution may be temporarily high and burial of benthic organisms in the vicinity of drilling operations could occur. The EIS prepared for the five-year program as well as sale-specific EIS's and the related management documents will address the issue of drilling fluids discharged during field development, to the extent potential environmental problems from this phase of OCS operations may exist in specific settings.

D. Overview of Methodology and Analytical Approach

1. Introduction

The object of this analysis is to estimate the present discounted value of the costs of OCS oil and gas development for each planning area. To achieve this objective, the analysis proceeds through several steps. These steps are illustrated in the accompanying simplified flow chart (figure 1), and described in general terms below. A more detailed discussion of the analytical approach, assumptions and data used is presented in succeeding sections and attachments.

The two basic types of costs considered in this appendix are oil spill-related costs and non-spill costs. An overview of the approaches used to estimate each of these categories of costs follows.

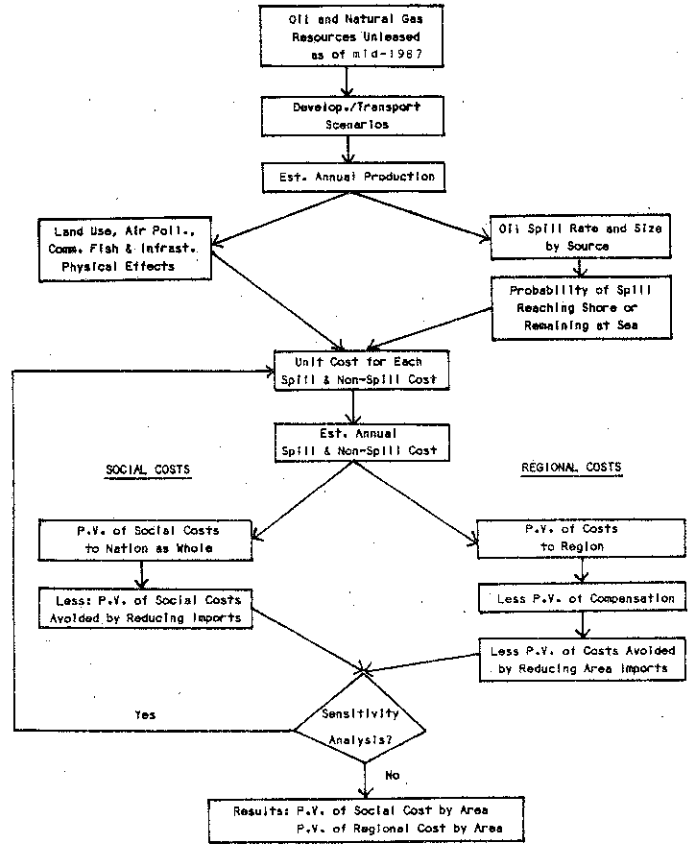
2. Oil Spill Costs

For each OCS area, estimated oil spill costs are determined by several factors. The principal factors include the scale of annual oil production; the estimated number (rate) of oil spills per unit of annual



Figure 1

SIMPLIFIED
FLOW DIAGRAM FOR ANALYSIS OF SOCIAL
AND REGIONAL COSTS FOR EACH O.C.S. AREA



production; the estimated average size of spills; the chance that spills which do occur will strike land; and the marine resources and economic characteristics and the environmental productivity and sensitivity of each OCS area.

Estimates of the leasable oil resources unleased as of mid-1987 (see SID Table 1), and the development and transportation scenario (time to initial, peak, and final production; mode of oil transport) provide the point of departure for estimating each area's oil spill costs. The resource estimates used to estimate potential social and regional costs are those developed in Appendix F using the low and high starting oil price assumptions of $14 and $29 per barrel (see Appendix F, Table 8-1). Given this information, obtained from Interior Department sources, annual oil production is estimated for each OCS area using the procedure and information explained in Attachment A. The estimated resources and the development and transportation scenarios vary widely from OCS area to area; consequently, the estimated time pattern and rate of oil production differs considerably among OCS areas.

Using the estimated annual oil production for each area, the rate (number) and size of large and small spills are established. The number of large spills (≥ 1,000 barrels) per billion barrels of oil for each source (production platforms, pipelines and tankers) is adopted from Lanfear and Amstutz (1983). Their results show that spill rates by source can be assumed to be the same for each area; this assumption also is incorporated in the analysis which follows. The estimated "typical" spill size for large platform and pipeline spills also is adopted from information on individual spills presented in Lanfear and Amstutz (1983). For vessels the large spill size is estimated from the Minerals Management Service vessel spill data file for spills in U.S. waters for the period 1957-1985. Information for small spill sizes is based on the record of small spills in the Gulf of Mexico for 1974-1983. A detailed discussion of the sources and assumptions used to estimate spill rates and sizes is presented in Section III.A.1.

Given the estimated total spillage for each area, the next step is to estimate the amount of spilled oil expected to come ashore. This number is significant because, generally, the costs per barrel are considerably higher for spilled oil which comes ashore than for oil which remains at sea. The former requires costly onshore removal operations and imposes a variety of additional costs, such as recreation losses, not associated with spills which stay at sea.

The estimated probability that a spill will strike land, given that it occurs, is based on several hundred to two thousand oil spill trajectory runs made for each planning area as part of previous studies by the OCS oil spill modeling group in the Minerals Management Service. Descriptions of the modeling approach used can be found in the appendix section of any sale specific EIS (e.g., Final EIS, OCS Sale No. 52, Appendix D) or in Smith, Slack, Wyant and Lanfear (1982). Since each of the several hundred individual oil spill trajectories is based on a specific area's likely resource locations, transportation routes and on historic data concerning prevailing winds and currents in the area, the probability figure used in this analysis can be regarded as a weighted average reflecting the overall chance that a given spill will come ashore. The model runs allow the expected amount of spilled oil thirty days to reach land. This is a highly conservative standard because



spilled oil weathers considerably after only a few days. Spills which do not come ashore, of course, remain at sea. The results indicating the estimated amount of spillage to come ashore in each area play a key role in the subsequent analysis of costs.

Once OCS oil production and the amount of oil spillage by year have been estimated, estimates of annual social and regional costs by area are developed. Basically, total oil spill costs are estimated by multiplying estimated unit costs per barrel spilled times the annual estimated spillage in each area. Constant marginal and average costs are assumed, for all oil spill costs, over the range of spills considered. All coefficients are expressed in constant 1987 dollars.

For oil spill costs, the unit cost coefficients developed in this study measure the costs reasonably expected to be incurred, by area, per barrel of oil spilled. These coefficients are adapted from available case studies of oil spill costs, modified by information from prior OCS lease sale EIS's and other sources. In general, the cost-per-barrel coefficients differ by (1) type of cost considered (e.g., oil spill control and cleanup costs vs. commercial fishery losses), (2) by planning area, reflecting the different resources, marine uses, and environmental sensitivity and productivity of each area, and (3) whether or not spilled oil comes ashore or remains at sea.

3. Non-oil spill costs

For non-oil spill costs, the cost coefficient is based on total OCS activity measured in <u>billions of barrels of oil equivalent</u> (BBOE), where natural gas is converted to equivalent barrels of oil.3/ For example, in the case of costs resulting from physical conflicts between commercial fishing and OCS hydrocarbon development or from alteration of wetlands, costs are assumed to begin one year after a lease sale and to increase until peak production in an area is achieved. For possible air quality losses, these costs are related to total annual oil and natural gas production.

Once the prospective oil spill and non-oil spill unit costs of producing oil and natural gas in an area are estimated following the general approach outlined above, the total social and regional costs of developing all of the leasable resources in each area are estimated. Social and regional costs are evaluated for each area <u>as if</u> all unleased resources are leased as of a common reference date, mid-1987. For this purpose, all costs are assessed on the basis of their present discounted value. The use of present discounted values is essential because costs incurred within an area in different time periods can only be compared when a common yardstick is used--here, the present discounted value of costs as of mid-1987. Use of present discounted values also permits an assessment of the net social value (development benefits minus social costs) of OCS oil and gas development by area in comparable dollar terms.

E. Sources of Information

Among the key sources of information used in this analysis are the following:

(1) Oil and gas resource information, development and transportation scenarios, oil spill trajectories, by area, and spill rates by source are based on extensive Interior Department analyses,

(2) Data on oil spill costs draws heavily on the findings of economic case studies of the cost of specific oil spills, modified by information from EIS's, the appendices on marine productivity and environmental sensitivity, and other sources to reflect the different characteristics of each OCS planning area, and

(3) Non-oil spill-related costs are adapted from government statistics and estimates in the available literature.

Because the literature potentially applicable to the issues examined herein is so vast, considerable judgement was exercised concerning which and how studies could be used in the present effort. The large size and varied nature of the literature make it difficult to characterize. In general, however, particular attention was given to studies that were based on the same standard economic concepts employed in this analysis, were reasonably well documented, and were judged to be of reasonable quality. The specific sources of information consulted and used are documented in the text and summarized in the list of references.

F. Important Qualifications

Despite the fact that the best available information has been used in this analysis, the many uncertainties involved, the inherently difficult problems associated with measuring many social costs, and limitations in the state of the art are such that caution is required in using the numerical results. Moreover, in a number of cases quantitative analysis of issues simply is not possible.

As a result of the difficulties inherent in the measurement of social costs, when judgement was required due to uncertainty concerning a cost estimate or an assumption to be used, a conservative, high-cost approach was adopted, provided a reasonable-high cost estimate was available. Specific examples of this conservative approach include:

(1) Oil spills predicted by the oil spill trajectory model to reach shore may not actually strike land because of prevention measures (e.g., booms or at-sea recovery).

(2) Spills reaching shore may not impose tourism and recreation losses, depending upon the specific section of shoreline contacted, the season in which a spill occurs and the speed and thoroughness of cleanup operations.

(3) In general, the actual per barrel cost of oil reaching shore may be lower than the cost per barrel figures based on the oil spill case studies used because the spills studied were very close to shore, allowing for relatively little weathering of the oil.



(4) Existing mitigating or regulatory measures, such as precluding the alteration of wetlands by shoreside pipelines or requiring a reduction in potential air pollution emissions, can reduce or eliminate many potential social costs (although costs of compliance are not considered here because they are production costs which are part of the net economic benefits calculations).

(5) Finally, several possible beneficial aspects of OCS oil and gas development are ignored. For example, platforms in some OCS areas serve as artificial reefs, improving the quality of recreational fishing (U.S. Dept. of Interior, MMS 84-0006, 1984). Also, offshore operators have provided emergency assistance to fishermen in remote areas (see, e.g., Centaur Associates, Inc., 1984, pp. 266-268). Further, additional OCS natural gas production will substitute for other energy products, thereby reducing air pollution problems (or air pollution control costs) associated with energy consumption. However, none of these beneficial effects are considered in this analysis because they are beyond the scope of the present effort.

Notwithstanding the use of the best available information and assumptions which provide a high estimate of social and regional costs, informed judgement and simplifying assumptions necessarily play important roles in this analysis. Every effort has been made to document data sources and to state explicitly the methodology and assumptions employed in order to give the reader the opportunity to judge the reasonableness of the results. Also, sensitivity analyses are used to examine how costs respond to variations in (1) the estimates of unit costs, (2) leasable resource estimates associated with different starting oil prices, and (3) methodologies for estimating some social costs.

In summary, it is important to stress that the many uncertainties involved, the aggregated planning-area level of the analysis, and severe limitations in the state of the art for quantifying economic damages make it impossible to develop precise estimates of social costs or to present confidence intervals for these costs. Pre-sale estimates of hydrocarbon resources and their location and composition (oil or natural gas) are highly uncertain. The timing and location of any spills are uncertain, as are the extent to which spill containment and cleanup would reduce potential damages in a given case. In light of the many difficulties inherent in estimating social costs, attention should be focused more on the relative ranking of planning areas than on the precise numerical results. Finally, it is noted that non-quantifiable social costs are considered elsewhere in the Section 18 analysis. The EIS accompanying the proposed five-year schedule and the EIS's associated with specific lease sales discuss non-quantifiable issues in qualitative terms.

## G. Summary of Results for OCS Planning Areas

### 1. Introduction

Using the approach outlined above (and described in detail in succeeding sections), the present value of the potential social and regional costs from producing all leasable resources unleased as of mid 1987, have been estimated for each OCS area. Only the aggregated oil spill and non-spill cost results for each area are presented in this section. A more extensive summary of the results is contained in Section III.B.3, and a detailed listing of the individual oil spill and non-spill costs for each OCS area is presented in Attachments B and C. In addition, basic information and summary results for each OCS area are contained in Attachment D.

### 2. Summary of Estimated Potential Social Costs Results

Tables I.G.1 and I.G.2 summarize the estimated present discounted value of the potential social costs for each OCS area as a result of producing and transporting all of the estimated leasable resources unleased as of mid-1987 for the $14 and $29 starting oil prices. As noted above, the present value calculations are based on the assumption that all resources are leased in mid-1987.

Table I.G.1 presents the results for the $29 starting oil price. Using the Western Gulf of Mexico as an example, the results in this table should be interpreted as described below.

The total present discounted value of the oil spill costs plus the non-oil spill costs for the Western Gulf of Mexico is $41.7 million in constant 1987 dollars (column 3 of Table I.G.1). This figure represents the total, quantifiable potential social costs resulting from the production and transportation of all of the area's resources which are unleased but are economically leasable as of mid-1987. However, the estimate of potential social costs of $41.7 million does not yet recognize the social costs <u>avoided</u> because oil and natural gas from the Western Gulf of Mexico will back out imports in several planning areas across the Nation, thereby reducing foreign tanker spills in those areas. Hence, the $41.7 million potential social cost figure represents "gross" social costs.

The estimated social costs avoided when Western Gulf of Mexico oil and natural gas backs out imports is $5.9 million (Column 4 of Table I.G.1). After the social costs avoided are subtracted from gross social costs, we arrive at net social costs of $35.8 million for the Western Gulf of Mexico (Column 5). The $35.8 million is the estimated potential net social cost to the Nation as a whole of developing all of the Western Gulf of Mexico leasable oil and gas resources unleased as of mid-1987. The results for all of the other OCS planning areas reported in Tables I.G.1 and I.G.2 are to be interpreted in the same way.

At a starting price of $29 a barrel for oil, estimated potential net social costs range from $42.3 million for the Central Gulf of Mexico to less than $1 million for several Alaskan and lower 48 OCS areas (Table I.G.1). The net social cost estimates for each planning area at the $14 per barrel starting oil price range from $41.8 million for the Central Gulf to less than $1 million for a number of Alaskan OCS areas and for



Table I.G.1 Summary of the Present Discounted Value of Estimated Potential Social Costs for Each OCS Planning Area: $29 per Barrel Starting Price (Millions of 1987 dollars)

| AREA | (1) OIL SPILL COSTS | (2) NON SPILL COSTS | (3)=(1)+(2) GROSS SOCIAL COSTS | (4) LESS: COST AVOIDED FROM REDUCED IMPORTS[a] | (5)=(3)-(4) TOTAL NET DISCOUNTED SOCIAL COSTS[b] |
|---|---|---|---|---|---|
| CGOM | 34.7 | 16.0 | 50.7 | 8.4 | 42.3 |
| WESTGOM | 19.2 | 22.5 | 41.7 | 5.9 | 35.8 |
| NAVARIN | 9.4 | 9.5 | 18.9 | 3.2 | 15.7 |
| S.CALIF | 11.3 | 5.3 | 16.7 | 4.3 | 12.3 |
| N.CALIF | 3.4 | 4.4 | 7.8 | 1.5 | 6.3 |
| EASTGOM | 3.8 | 2.9 | 6.7 | 1.1 | 5.6 |
| S.ATLAN | 1.9 | 3.9 | 5.8 | 0.8 | 5.0 |
| ST.GEORGE | 1.3 | 3.6 | 4.9 | 0.5 | 4.4 |
| BEAUFRT | 4.5 | 1.4 | 5.9 | 1.4 | 4.4 |
| CEN.CALIF | 2.5 | 2.2 | 4.8 | 1.1 | 3.6 |
| CHUKCHI | 4.5 | 0.3 | 4.8 | 1.6 | 3.2 |
| MID-ATLAN | 1.0 | 1.3 | 2.3 | 0.3 | 2.0 |
| N.ATLAN | 0.1 | 0.7 | 0.8 | 0.1 | 0.7 |
| NORTON | 0.3 | 0.4 | 0.7 | 0.1 | 0.6 |
| GULFALASKA | 0.2 | 0.3 | 0.5 | 0.0 | 0.5 |
| ORE/WASH | 0.3 | 0.3 | 0.6 | 0.1 | 0.5 |
| N.ALEUTIAN | 0.2 | 0.2 | 0.4 | 0.0 | 0.4 |
| STR OF FLOR | 0.0 | 0.3 | 0.4 | 0.0 | 0.4 |
| KODIAK | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| HOPE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SHUMAGIN | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| COOK INLET | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

[a] Estimated Potential Social costs avoided to the nation as a whole from reduced needs for imported oil, assuming reduced imports (and associated oil spills) are distributed across OCS planning areas in the same proportion as indicated in Table III.A.3.1.
[b] Zero costs indicated in the table occur because area contains negligible leasable resources and estimated costs are less than $.1 million.

Table I.G.2 Summary of the Present Discounted Value of Estimated Potential Social Costs for Each OCS Planning Area: $14 per Barrel Starting Price (Millions of 1987 dollars)

| AREA | (1) OIL SPILL COSTS | (2) NON SPILL COSTS | (3)=(1)+(2) GROSS SOCIAL COSTS | (4) LESS: COST AVOIDED FROM REDUCED IMPORTS[a] | (5)=(3)-(4) TOTAL NET DISCOUNTED SOCIAL COSTS[b] |
|---|---|---|---|---|---|
| CGOM | 33.2 | 15.6 | 48.8 | 7.0 | 41.8 |
| WESTGOM | 15.7 | 18.9 | 34.6 | 4.2 | 30.4 |
| S.CALIF | 4.9 | 2.8 | 7.7 | 1.6 | 6.0 |
| N.CALIF | 1.5 | 2.7 | 4.2 | 0.6 | 3.6 |
| EASTGOM | 1.4 | 1.8 | 3.2 | 0.4 | 2.8 |
| CEN.CALIF | 1.3 | 1.4 | 2.7 | 0.5 | 2.2 |
| S.ATLAN | 0.7 | 1.7 | 2.4 | 0.2 | 2.1 |
| MID-ATLAN | 0.5 | 0.8 | 1.3 | 0.1 | 1.1 |
| N.ATLAN | 0.0 | 0.5 | 0.5 | 0.0 | 0.5 |
| ORE/WASH | 0.2 | 0.2 | 0.5 | 0.1 | 0.4 |
| NAVARIN | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| BEAUFRT | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| CHUKCHI | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| ST.GEORGE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| N.ALEUTIAN | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| GULFALASKA | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| NORTON | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| KODIAK | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| HOPE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SHUMAGIN | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| COOK INLET | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| STR OF FLOR | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

[a] Estimated Potential Social costs avoided to the nation as a whole from reduced needs for imported oil, assuming reduced imports (and associated oil spills) are distributed across OCS planning areas in the same proportion as indicated in Table III.A.3.1.
[b] Zero costs indicated in the table occur because area contains negligible leasable resources and estimated costs are less than $.1 million.



the No. Atlantic, Oregon/Washington and for the Straits of Florida areas. The estimated potential social costs for the Central Gulf of Mexico do not differ much when the starting price of oil drops from $29 to $14 per barrel because the leasable resources for this area do not change much over this price range. However, for most other OCS areas leasable resource estimates and estimates of social costs decline substantially as the initial oil price is decreased from $29 to $14 per barrel.

Generally speaking, when comparing OCS planning areas at a specific oil starting price, there is a direct association between an area's total potential social cost and the total leasable hydrocarbon resources estimated to be contained in the area. Total hydrocarbon resources alone, however, do not determine total potential social costs. The oil-gas resource composition, the transportation mode(s), the estimated chance that spills which occur will reach shore, together with the characteristics of an area's marine and coastal resources and environmental productivity and sensitivity, also influence total social costs. For example, at the $29 starting oil price, the Central Gulf of Mexico has total hydrocarbon resources which are slightly less than, but potential social costs which are almost twenty percent greater than, the corresponding estimates for the Western Gulf of Mexico (Table I.G.1). One important reason for the large difference in social costs estimates for the two areas is that the Central Gulf of Mexico is expected to contain considerably more oil than the Western Gulf. Hence, estimated oil spillage is greater for the Central Gulf of Mexico than for the Western Gulf of Mexico. Other reasons for this large difference in the estimated total potential social costs between the two areas are that the Central Gulf has more valuable commercial fisheries, a higher environmental productivity and sensitivity ranking and is potentially more vulnerable to wetland alterations than the Western Gulf of Mexico (see Section II).

The net effect of all of the factors influencing social costs can be examined by assessing the social costs per unit of production--here measured as the potential social cost per billion barrels of oil equivalent (BBOE) (Table I.G.3). Estimated potential social costs <u>per BBOE</u> at the $29 oil starting price range from $36.5 million for the Straits of Florida area to $6.5 million for the South Atlantic and are not directly correlated with an area's total unleased resources.

The relatively high potential social cost per BBOE for the Straits of Florida ($36.5 million) is explained by a combination of possible wetland alterations and low resource estimates for this area. The use of a pipeline to transport natural gas from this area could alter some coastal wetlands. The extent of coastal wetland alteration is essentially a "fixed" cost because it depends primarily on the number of pipelines (one in this case) and is not very sensitive to changes in resource estimates. Because the resource estimate for this area is so low (.001 BBOE), the estimated social cost per BBOE is highly sensitive to fixed costs. Hence, for this reason, the potential social cost per BBOE for the Straits of Florida is relatively high, even though estimated total potential social cost for this area is low.

The relatively low cost per BBOE for the South Atlantic ($6.5 million) is explained by the fact that most of the modest resources for this OCS planning area are expected to be natural gas. Hence, negligible oil spillage would be expected, and, further, of the spillage which could

Table I.G.3 Total and per BBOE net Estimated Potential Social Costs
$29 per Barrel Starting Price
(in Millions of 1987 Dollars)

| | TOTAL NET SOCIAL COSTS | NET COSTS PER BBOE*) |
|---|---|---|
| STR OF FLORID | 0.4 | 36.5 |
| NORTON | 0.6 | 30.1 |
| NAVARIN | 15.7 | 19.9 |
| N.ALEUTIAN | 0.4 | 18.8 |
| ST.GEORGE | 4.4 | 16.8 |
| GULFALASKA | 0.5 | 16.4 |
| CEN.CALIF | 3.6 | 15.8 |
| N.CALIF | 6.3 | 15.4 |
| S.CALIF | 12.3 | 15.0 |
| BEAUFRT | 4.4 | 14.3 |
| EASTGOM | 5.6 | 11.9 |
| N.ATLAN | 0.7 | 10.6 |
| CGOM | 42.3 | 10.3 |
| MID-ATLAN | 2.0 | 8.6 |
| CHUKCHI | 3.2 | 8.0 |
| WESTGOM | 35.8 | 7.7 |
| ORE/WASH | 0.5 | 7.5 |
| S.ATLAN | 5.0 | 6.5 |
| KODIAK | 0.0 | 0.0 |
| HOPE | 0.0 | 0.0 |
| SHUMAGIN | 0.0 | 0.0 |
| COOK INLET | 0.0 | 0.0 |

*) Zero costs indicated in the table occur because area contains negligible leasable resources and estimated costs are less than $.1 million.



occur, only a small share (about 4 percent) is estimated to reach shore (Table II.A.1.1).

At a starting price for oil of $14, a number of OCS areas show zero estimated net social costs per BBOE because leasable resources drop to zero for these areas at this starting price. For areas with non-zero leasable resources, the net social costs per BBOE range from $48.0 million for the No. Atlantic to $7.8 million for Oregon/Washington. Again, the relatively high cost per BBOE for the North Atlantic stems from the fixed cost which could result if an OCS pipeline causes wetland losses in this area.

One important factor determining the estimated social cost per BBOE is the estimated transportation mode for oil. Domestic tankers result in considerably less spillage (19,119 per billion barrels of oil (BBO)) than pipelines (41,449 per BBO), using the average spill sizes and spill rates employed in this analysis. Hence, other things being the same, the more that an area relies on pipelines rather than domestic vessels to transport OCS oil, the higher will be its potential social costs per BBOE.4/

The social cost estimates presented in Tables I.G.1 and I.G.2 differ markedly from the social cost estimates (called external costs) made in conjunction with the 1982 Secretarial Issue Document for the Tentative Proposed 5-Year OCS Leasing Schedule (Appendix 8). A detailed comparison of the estimation of social costs made in this Appendix with the social cost analysis carried out in the 1982 study is presented in Section I.H. and is not repeated here.

Regarding the composition of potential social costs, an important conclusion is that oil spill costs exceed non-oil spill costs for most OCS areas. For the lower 48 OCS planning areas, the most important potential oil spill social costs are tourism and recreation, cleanup and control, commercial fisheries and ecological costs. For the Alaskan OCS areas, cleanup and control costs, ecological costs and possible subsistence losses are the principal estimated potential oil spill costs (see Attachment B).

For the non-oil spill costs, estimated potential wetland and air quality costs are among the largest potential costs in this category for several OCS area (see Attachment C), though these cost are small relative to total potential social costs. It is important to stress, however, that by regulatory authority the MMS limits air emission from OCS operations (or employs offsets) to avoid significantly affecting onshore ambient air quality. Furthermore, states through their permitting authority have considerable control over wetland use. For these reasons, non-oil spill costs may be overstated. Potential infrastructure costs (planning costs) could be relatively large for some areas, especially in remote Alaskan OCS areas and in Central and Northern California and in the Western Gulf of Mexico because of the significant amount of unleased resources leasable as of mid-1987 for this OCS area.

### 3. Summary of Estimated Potential Regional Cost Estimates

As explained in Section I.B., the concept of regional costs is important when assessing the regional distribution of the potential social costs of producing the hydrocarbon resources in each area. The concept of regional costs was introduced to indicate the estimated potential costs borne by residents of geographic localities adjoining each OCS area as a result of the production of all of the leasable resources unleased in all planning areas as of mid-1987.

Tables I.G.4 and I.G.5 summarize the estimated potential aggregate regional costs for each OCS area, using the unit cost assumptions developed in Section II and the leasable resource estimates resulting from the starting oil prices of $29 and $14 dollars. The estimates are in present value terms, and the cost estimates are based on the assumption that all resources are leased in mid-1987. Extending our use of the Western Gulf of Mexico OCS area as an example, the information in Table I.G.4 should be interpreted as described below.

At the $29 starting oil price, the estimated total potential gross regional cost of $49.5 million for the Western Gulf of Mexico is the sum of all oil spill costs and all non-spill costs (column 1 plus column 2 in Table I.G.4). Note that the regional oil spill cost estimate (column 1 of Table I.G.4) generally exceeds the social cost estimate of oil spill costs (column 1 of Table I.G.1). For example, in the case of the Western Gulf of Mexico, potential regional oil spill costs are estimated to be $27.0 million, while oil spill social costs are only $19.2 million. The reasons for this outcome are that the estimate of regional oil spill costs for the Western Gulf of Mexico includes (1) oil spilled in this area as a result of the shipment into this area of production from other OCS areas and (2) tourism industry losses within the area from all estimated oil spillage. These two items are not included when estimating the social costs of OCS development in the Western Gulf of Mexico.

The estimated total potential regional cost of $49.5 million measures the potential costs imposed on residents of adjoining communities as a result of developing all of the leasable resources unleased as of mid-1987. However, the OCSLA provides for compensation for OCS-related oil spills and for commercial fishing gear damages. Also, oil and natural gas production in the Western Gulf of Mexico replaces imports of crude oil into this area, thereby reducing foreign tanker spills. An accurate assessment of potential costs to residents of this area, therefore, should be measured net of estimated compensation payments ($9.7 million) and net of the potential costs avoided by backing out foreign oil to this specific OCS area ($17.9 million).

In sum, at a starting oil price of $29, the net potential regional cost for the Western Gulf of Mexico is $21.8 million in 1987 dollars. This figure represents the net potential costs incurred by residents of communities contiguous to this OCS area as a consequence of producing and transporting all of the estimated leasable resources of all OCS areas. For other OCS planning areas the net regional cost ranges from $27.7 million for the Central Gulf of Mexico to minus $0.2 million for the Mid-Atlantic. A negative regional cost arises when costs associated with OCS oil and gas operations are more than offset by compensation payments and by reduced oil spills from foreign tankers. In the case of the Mid-Atlantic, regional oil spill and non-spill costs of $2.4 million are



Table I.G.4 **Estimated Potential Regional Costs by Area from Development of All Areas: $29 per Barrel Starting Price (Millions of 1987 Dollars)**

| AREA | (1) OIL SPILL COSTS IN REGION | (2) NON SPILL COSTS IN REGION | (3) COMPENSATION TO REGION | (4) IMPORT COSTS BACKED OUT OF REGION | (1)+(2)-(3)-(4) POTENTIAL NET COSTS TO THE REGION*' |
|---|---|---|---|---|---|
| CGON | 46.6 | 16.0 | 17.0 | 18.0 | 27.7 |
| WESTGOM | 27.0 | 22.5 | 9.7 | 17.9 | 21.8 |
| S.CALIF | 17.0 | 5.3 | 5.6 | 0.9 | 15.7 |
| NAVARIN | 8.7 | 9.5 | 4.3 | 0.0 | 13.9 |
| N.CALIF | 4.7 | 4.4 | 1.7 | 0.0 | 7.4 |
| EASTGOM | 5.0 | 2.9 | 1.8 | 0.1 | 6.1 |
| CEN.CALIF | 4.8 | 2.2 | 1.3 | 0.3 | 5.5 |
| S.ATLAN | 2.0 | 3.9 | 1.1 | 0.2 | 4.6 |
| ST.GEORGE | 1.2 | 3.6 | 0.6 | 0.0 | 4.2 |
| BEAUFRT | 4.2 | 1.4 | 2.0 | 0.0 | 3.6 |
| CHUKCHI | 4.2 | 0.3 | 2.0 | 0.0 | 2.5 |
| ORE/WASH | 1.5 | 0.3 | 0.3 | 0.4 | 1.2 |
| GULFALASKA | 0.5 | 0.3 | 0.2 | 0.0 | 0.7 |
| N.ATLAN | 0.1 | 0.7 | 0.1 | 0.1 | 0.6 |
| NORTON | 0.2 | 0.4 | 0.1 | 0.0 | 0.5 |
| N.ALEUTIAN | 0.2 | 0.2 | 0.1 | 0.0 | 0.3 |
| STR OF FLOR | 0.0 | 0.3 | 0.0 | 0.0 | 0.3 |
| SHUMAGIN | 0.1 | 0.0 | 0.0 | 0.0 | 0.1 |
| KODIAK | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| HOPE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| COOK INLET | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| MID-ATLAN | 1.1 | 1.3 | 0.5 | 2.1 | -0.2 |

*' Zero costs indicated in the table occur because area contains negligible leasable resources and estimated costs are less than 9.1 million.

offset by compensation payments of $0.5 million for OCS-related oil spills and commercial fishing gear damage. Also, regional costs of $2.1 million are avoided in the Mid-Atlantic because OCS oil production from all areas replaces imported oil, thereby reducing oil spills from foreign tankers.

At a $14 starting oil price, net regional costs range from $34.4 million for the Central Gulf of Mexico to negligible for several OCS areas (Table I.G.5). The net regional cost for the Western Gulf of Mexico at the $14 starting oil price ($24.5 million) actually is higher than at the $29 initial price for oil ($21.8 million). The principal reason for this outcome is that at the lower starting oil price, considerably less natural gas is leasable in this area (0.6 BBOE). Hence, less foreign oil is replaced at the lower price, so that oil spills from foreign tankers is correspondingly higher.

4. Social Cost Sensitivity Analysis

In recognition of the many uncertainties and inherent difficulties involved in the estimation of social costs, a sensitivity analysis was carried out to determine the magnitude of area potential social cost changes in response to changes in key variables used in the analysis. The sensitivity analysis examined how area social cost estimates might be altered if specific unit costs are presumed to be even higher than the conservative (i.e., high) costs developed in Section II. Wetlands, ecological and commercial fishing industry losses were selected for the sensitivity analyses because these costs are potentially quantitatively significant and inherently difficult to estimate.

Even the extreme sensitivity analysis case considered--where wetland acres altered, ecological costs and commercial fishing industry losses were all assumed to be 50 percent greater than the unit estimates developed in Section II--leads to a less than 30 percent increase in estimated potential net social costs. This is because (1) only a subset of all costs increases, and (2) the social costs avoided from backing out imported oil also increase, thereby moderating the net increase in potential social costs. The results of the extreme sensitivity analysis indicate that while the potential costs in each case considered are greater than the case results presented in Tables I.G.1 and I.G.2, the ranking of the ten high resource OCS areas by their potential social costs does not change (see Section III, Table III.B.2.7 and Table III.B.8).

H. Comparison With Results of Prior Section 18 Analysis of Social Costs (External Costs)

The analysis in this appendix differs from that carried out in 1982 in several important respects. In general, the present analysis uses updated, much lower oil and gas resource estimates and more recent oil spill rates and economic and other information than was employed in the 1982 study. In addition, the analysis carried out here, building upon the experience gained in the 1982 exercise, considerably extends and refines in a number of ways the previous study of social costs (called external costs in 1982).



Table I.G.5 Estimated Potential Regional Costs by Area from Development of All Areas: $14 per Barrel Starting Price (Millions of 1987 Dollars)

| AREA | (1) OIL SPILL COSTS IN REGION | (2) NON SPILL COSTS IN REGION | (3) COMPENSATION TO REGION | (4) IMPORT COSTS BACKED OUT OF REGION | (1)+(2)-(3)-(4) POTENTIAL NET COSTS TO THE REGION[a] |
|---|---|---|---|---|---|
| CGOM | 44.6 | 15.6 | 16.2 | 9.6 | 34.4 |
| WESTGOM | 22.1 | 18.9 | 8.0 | 8.4 | 24.5 |
| S.CALIF | 7.2 | 2.8 | 2.3 | 0.4 | 7.3 |
| N.CALIF | 2.0 | 2.7 | 0.7 | 0.0 | 3.9 |
| EASTGOM | 1.9 | 1.8 | 0.7 | 0.0 | 3.0 |
| CEN.CALIF | 2.4 | 1.4 | 0.6 | 0.1 | 3.0 |
| S.ATLAN | 0.7 | 1.7 | 0.4 | 0.1 | 1.9 |
| ORE/WASH | 0.6 | 0.2 | 0.1 | 0.2 | 0.5 |
| N.ATLAN | 0.0 | 0.5 | 0.0 | 0.1 | 0.4 |
| MID-ATLAN | 0.5 | 0.8 | 0.3 | 1.0 | 0.1 |
| NAVARIN | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| BEAUFRT | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| CHUKCHI | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| ST.GEORGE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| N.ALEUTIAN | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| GULFALASKA | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| NORTON | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| KODIAK | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| HOPE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SHUMAGIN | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| COOK INLET | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| STR OF FLOR | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

a) Zero costs indicated in the table occur because area contains negligible leasable resources and estimated costs are less than $.1 million.

The overall effect of using updated resource assumptions and other data and refined concepts and techniques is (1) to increase the estimated potential social costs of developing the oil and gas resources of the Central and Western Gulf of Mexico and (2) to decrease the potential costs of developing the hydrocarbon resources in other areas. A summary comparison of the 1982 and the 1987 resource estimates and the estimated potential social costs, for each OCS area, is presented in Table I.H.1. The 1987 resource estimates are based on the $29 starting oil price, which is closer to the price of oil in 1982 than the $14 oil starting price assumption.

The following five factors explain, in part, the differences between the 1982 and the 1987 estimates of potential social costs.

1. For every OCS area, the estimates of leasable resources used in this analysis are considerably lower than those used in the 1982 study of potential social costs. For example, for the Central Gulf of Mexico, the area with the highest hydrocarbon potential in 1982 and the second highest in 1987, the 1987 resource estimate is less than 50 percent of the resource estimate made in 1982. The 1987 resource estimates for the North Atlantic and the Beaufort Sea are only a very small fraction of the 1982 resource estimates for these areas (Table I.H.1).

The lower 1987 resource estimates reflect the leasing of resources since 1982, updated geologic information acquired as a result of drilling activity during the intervening period and trends in prices, potential costs, drilling depths and related factors. Other things being the same, lower resource estimates lead to lower estimates of potential social and regional costs.

2. The oil spill rates for large spills for each source used in this analysis differ from those adopted in 1982. This is an especially important consideration for oil transported by tanker. The 1982 study used an estimated tanker spill rate of 3.87 large spills per billion barrels of oil transported. In comparison, this analysis uses a tanker spill rate of 1.3 spills per billion barrels, based on the updated results of the statistical analysis of oil spills by Lanfear and Amstutz (1983) which became available subsequent to publication of the 1982 study. Also, the analysis in this appendix uses an estimated average spill size of 14,707 barrels for domestic tanker spills and 20,769 for foreign vessels in U.S. waters (see section III.B). In contrast, the 1982 study used an average tanker spill size of 230,000 barrels for all spills. A comparison of the 1982 and 1987 oil spill rates and spill sizes, for each source, is presented in Table I.H.2.

One effect of using considerably lower spill rates for tankers and a very substantially lower average spill size for tanker spills is to lower the potential gross social and regional costs of OCS hydrocarbon development relative to what they would be had the 1982 tanker spill rate and average spill size been used. The _net_ effect, however, is to increase the estimates of potential social and regional costs, particularly for areas that rely on pipelines to transport oil. This seemingly inconsistent result occurs because the potential social cost avoided from reduced import-related oil spills is considerably smaller when the latest tanker spill statistics are used.



Table I.H.1. Comparison of Estimates of Resources and Estimated Potential Social Costs for 1982 and 1987 for Each Planning Areaa/ (dollar figures in millions of $1987)b/

| Area | 1982 Resourcese/ (BBOE) | 1982 Social Cost | 1987d/ Resourcese/ (BBOE) | 1987d/ Social Cost |
|---|---|---|---|---|
| Central Gulf of Mexico | 9.5 | -$1,141 | 4.1 | $43 |
| Western Gulf of Mexico | 6.1 | -558 | 4.6 | 36 |
| So. California [1982]a/ | 2.3 | 496 | --- | -- |
| So. California [1987]a/ | --- | --- | .8 | 12 |
| Beaufort Sea | 5.4 | 2,665 | .3 | 4 |
| Cent. & No. California [1982]a/ | 1.2 | 570 | --- | -- |
| Cent. California [1987]a/ | --- | --- | .2 | 4 |
| No. California [1987]a/ | --- | --- | .4 | 6 |
| So. Atlantic | 1.6 | 471 | .8 | 5 |
| Navarin Basin | 1.9 | 558 | .8 | 16 |
| Mid-Atlantic (Old) | 4.7 | 157 | .2 | 2 |
| East. Gulf of Mexico | 1.2 | 856 | .5 | 6 |
| St. George | 0.9 | 422 | .3 | 4 |
| Chukchi Sea | 1.3 | 661 | .4 | 3 |
| No. Atlantic | 7.0 | 223 | .1 | 1 |
| Ore.-Wash. | --- | --- | .1 | neg.c/ |
| Gulf of Alaska | 0.7 | 335 | neg.c/ | neg.c/ |
| Norton | 0.4 | 149 | neg.c/ | neg.c/ |
| No. Aleutian | 0.4 | 174 | neg.c/ | neg.c/ |
| Straits of Florida | | | neg.c/ | neg.c/ |
| Kodiak | 0.7 | 310 | neg.c/ | neg.c/ |
| Shumagin | 0.2 | 74 | neg.c/ | neg.c/ |
| Hope | 0.1 | 12 | neg.c/ | neg.c/ |
| Cook Inlet | 0.2 | 1 | neg.c/ | neg.c/ |

a/Because the OCS area boundaries differ in some cases between the two periods, all areas may not exactly correspond.

b/1982 dollar values converted to 1987 dollars using the GNP implicit price deflator.

c/neg. = negligible: less than .1 BBOE or $1 million.

d/1987 figures are for $29 per barrel oil starting price.

e/The 1982 resource estimates were for developable resources, while the 1987 resource estimates are for leasable resources. See Appendix F for an explanation of the difference between these two resource concepts.

Table I.H.2. Comparison of 1982 and 1987 Oil Spill Rates and Sizes for Large Spills (equal to or greater than 1,000 bbls) for Each Source a/

| Source | Estimated number of spills per BBO | | Average spill size (equal to or greater than 1,000 bbls) | |
|---|---|---|---|---|
| | 1982 | 1987 | 1982 | 1987 |
| Platforms | 0.79 | 1.0 | 21,000 | 18,378 |
| Pipelines | 1.82 | 1.6 | 26,000 | 25,937 |
| Tankers | | | | |
| Foreign Vessels | 3.87 | 1.3 | 230,000 | 20,769 |
| Domestic Vessels | 3.87 | 1.3 | 230,000 | 14,707 |

a/The 1982 spill rates and sizes are taken from the 1982 Secretarial Issues Document for the Tentative Proposed 5-Year OCS Leasing Program, Appendix 8, pp. 5-6. The sources for the 1987 spill rates and sizes are described in the text.



The impact of using the updated, generally lower (except for platforms) spill rates and sizes can best be illustrated with an example. Consider a hypothetical OCS area with 400 million barrels of leasable oil resources, 75 percent of which will be delivered to refineries by pipeline, 25 percent by tankers. All OCS oil is assumed to replace imported oil on a barrel-for-barrel basis. Foreign tankers are assumed to have the same spill rate as domestic tankers but a larger spill size, 20,769 vs. 14,707, as noted in a preceding paragraph. However, one half of foreign tanker spillage is assumed to occur outside United States waters.

Using the spill rates and sizes indicated in Table I.H.2, the estimated spillage from OCS production and transportation employing the 1982 rates is 86,625 barrels greater (109,842-23,217) than the estimated spillage obtained using the 1987 rates (Table I.H.3). Hence, for given oil resources, a given transportation scenario using pipeline and tankers and given unit oil spill costs, use of the 1987 spill rates and sizes lead to substantially higher "gross" oil spill costs than does use of the 1982 spill rates and sizes.

On the other hand, social costs to the Nation as a whole are measured net of the social costs avoided when imports are backed out by OCS production. Because the 1982 study of social costs used high spill rates and a very large average spill size for tankers, the example results indicate that a substantial amount of oil spillage from foreign tankers was avoided (178,020 barrels) because OCS oil production (primarily transported by pipelines) replaced imports. In fact, the net effect of replacing imported oil with OCS production using the 1982 spill rates is to lead to a net reduction in the total amount of oil discharged into domestic waters of 68,178 barrels (109,842-178,020) when both OCS operations and backed out imports are considered. Thus, the overall effect of using the 1982 rates in this example is to lead to a substantial social cost savings -- which was, in fact, the result obtained for the Central and Western Gulf of Mexico OCS areas in 1982 (see Table I.H.1).

To make the same point another way, the lower 1987 oil spill sizes and spill rates result in substantially smaller estimated discharges from OCS production and transportation (23,217 barrels spilled vs. 109,842 barrels using the 1982 rates). Hence, if all other factors are the same (resources, transport mix, unit oil spill costs), the 1987 spill rates and sizes lead to substantially lower estimated social costs resulting from OCS operations. However, the social costs avoided by reducing the amount of imported oil--172,620 fewer barrels of oil are spilled from foreign tankers in this example--also is lower when the 1987 oil spill rates and sizes are used rather than those used in 1982. Therefore, the overall estimated amount of oil spillage, taking into account both OCS production and backed out imports, is higher when the 1987 vs. the 1982 oil spill rates and sizes are used (17,817 vs. minus 68,178 in Table I.H.3). The fact that the spill rates and sizes used in this analysis are lower than those used in 1982 explains why the social cost estimates for the Central and Western Gulf of Mexico are positive in 1987, although they were negative (indicating a savings) in 1982 (Table I.H.1).

The effects of using different spill rates and sizes in 1982 and 1987 vary from OCS area to area, depending upon the amount of resources, the oil-gas composition of the resources and the extent to which pipelines vs. tankers are used. The computer model developed as part of

Table I.H.3. Comparison of Estimated Oil Spillage from a Hypothetical OCS Area Using the 1982 and 1987 Spill Rates and Sizes.
Assumed area resources: .4 Billion Barrels of Oil
Assumed transport modes: 75% pipeline, 25% tanker

| Source | Estimated Spillage Using Spill Rates & Sizes Applicable in:a/ | | Difference |
|---|---|---|---|
| | 1982 | 1987 | (1982-1987) |
| Platform | 6,636 | 7,351 | (715) |
| Pipeline | 14,196 | 12,450 | 1,746 |
| Tankers | 89,010 | 1,912 | 87,298 |
| Small Spills | 0 | 1,504 | (1,504) |
| Total from OCS production & transportation | 109,842 | 23,217 | 86,625 |
| Less: Spillage avoided by reducing imports | 178,020 | 5,400 | 172,620 |
| Total | (68,178) | 17,817 | (85,995) |

a/From Table I.H.2



this analysis has been used to analyze the interaction of these and other factors.

3. This appendix employs a stricter definition of costs based on economic concepts than was used in 1982. For example, the 1982 study employed the "life support" concept which involves use of a net energy analysis to evaluate wetland losses (see Section II.B.2 for a discussion of this approach). This approach resulted in an estimated loss per acre of about $114.1 thousand (in 1987 dollars), assumed to be constant across all OCS areas. However useful the concept may be for scientific studies, there is no economic justification for using the life support approach to estimate economic losses from wetland alterations (Shabman and Batie, 1978). In contrast, this study uses a "components" approach for valuing wetlands damages, whereby an explicit effort is made to account for each category of area-specific benefits foregone when wetlands are altered (see Section II.B.2).

The effect of using the components approach to value wetland alterations is to lower wetland damages per acre compared to what would have been estimated using the 1982 approach. Nonetheless, the approach used in this appendix is believed to provide a conservative (i.e., high) wetland damage estimate because, among other reasons, individual states and the Federal government have considerable authority to control wetland losses (see Section II.B.2).

4. A number of costs not considered in the 1982 study are included in this appendix (e.g., commercial fisheries area preemption and gear conflict losses and secondary (multiplier) losses from commercial fishing oil spill losses). Also in this appendix, costs are estimated on a more area-specific basis than was the case in the 1982 effort. For example, wetland losses and commercial fishing losses and associated secondary effects are geographically disaggregated to reflect differences among OCS areas; and oil spill cleanup and control costs are recognized to be higher for Alaska than for the "lower 48".

5. Another refinement in the present analysis of social costs is that a procedure is developed to estimate annual production of the unleased resources in each area, given the development timing scenarios (time to initial and peak production, peak production as a percent of total production, and total production period) estimated by the MMS for each area. The use of this procedure, explained in Attachment A, allows one to estimate potential social and regional costs on an annual basis. In contrast, the 1982 study used highly simplified assumptions to estimate the timing of costs (e.g., all oil spills and spill damages were assumed to occur three years after initial production in each area, and air pollution damages were based on an assumed, constant production per year). On balance, the effect of this new, more reasonable approach for estimating annual potential costs is to lower the present discounted value of the potential costs of OCS production, relative to what the estimates would have been using the highly simplified 1982 approach.

II. Development of Unit Cost Estimates

A. Estimates of Potential Oil Spill Costs

1. Control and Cleanup Costs

Oil spill control and cleanup costs are comprised of the opportunity cost of the resources employed in control and cleanup operations. Market prices are good indicators of opportunity costs for most resources employed in control and cleanup operations, but evaluation problems arise when government resources or volunteers are used or when long-lived equipment is purchased to respond to a particular spill (Anderson, Congar and Meade, 1983). Control and cleanup costs typically represent the single largest market-valued cost of a spill, often accounting for fifty percent or more of its total cost. Hence, this category of costs merits special attention.

The costs considered here include the cost of manpower, equipment, supplies and services used: (1) to stem the loss of oil from a tanker, pipeline, or offshore oil facility, (2) to recover the oil at sea or prevent it from reaching shore, and (3) to remove and recover the oil, should the spill come ashore. The costs of any damages or restoration of the environment, however, are not considered here and are taken up in later sections of this analysis.

Table II.A.1.1 summarizes information from several major spills reported in the literature. Although some additional information is available concerning cleanup costs for other spills (see, e.g., Organization for Economic Cooperation and Economic Development, 1982), the spills cited are the most relevant for this report because they are reasonably well documented and are based on the same conventional economic concepts as employed in this analysis.

Several factors influence the per barrel cost of controlling and cleaning up a particular spill. As the results in Table II.A.1.1 indicate, whether or not a spill strikes shore is a very important determinant of the per barrel cost of controlling and cleaning up a spill. For spills which did hit land, the average per barrel cost in 1987 dollars was \$228, while for the one spill which remained at sea, the cost per barrel amounted to \$22. Because there is such a major difference in cost per barrel between spills which do and which do not hit land, later in this analysis considerable attention will be given to the estimated chance that spills in an OCS planning area will or will not strike shore.

The geographic location of an oil spill also will influence control and cleanup costs in some cases because of relative cost differences among regions. In particular, control and cleanup costs for a spill on the Alaskan OCS likely will be considerably higher than for a spill on the "lower 48" OCS, all else being equal. To allow for possible higher costs, Alaskan OCS cleanup and control costs are assumed to be 45 percent greater than for lower 48 OCS oil spills, based on the F.W. Dodge labor and materials construction cost index for Anchorage (L. A. McMahon, 1983, p. XII).



Table II.A.1.1 Control and Cleanup Costs

| Spill | Location | Year | Cost in \$ Millions Current | Cost in \$ Millions 1987a/ | Barrels (thousands)b/ | Cost Per Barrel 1987 dollars |
|---|---|---|---|---|---|---|
| Reached Shore | | | | | | |
| Zoe Colcotroni | Puerto Rico | 1973 | 7.3c/ | 18.1 | 36 | 505 |
| Amoco Cadiz | France | 1978 | 106-117d/ | 186.7-205.7 | 1,600 | 116-128 |
| Santa Barbara | United States | 1969 | 10.5e/ | 31.9 | 77 | 405 |
| STC-101 | United States | 1976 | 0.6f/ | 1.2 | 6 | 205 |
| Torrey Canyon | Great Britain & France | 1967 | 21.2g/ | 70.6 | 858 | 82 |
| Ixtoc I | Mexico & U.S. | 1979 | 120.3h/,i/ | 194.1 | 5,000 | 39 |
| Remained at Sea | | | | | | |
| Argo Merchant | United States | 1976 | 1.9f/ | 3.8 | 179 | 21 |

a/Using GNP implicit price index.

b/Conversion ratios used are: 42 gallons = 1 barrel and 1 metric ton = 7.33 barrels.

c/Sorensen (1977, p. 3).

d/U.S. Dept. of Commerce, NOAA (1983, p. 143).

e/Mead and Sorensen (1970, p. 225).

f/U.S. Comptroller General, General Accounting Office (1977, App. I, pp. 7-8).

g/Burrows, Rowley, and Owen (1974, p. 241).

h/U.S. Dept. of Interior, Bureau of Land Management (April, 1984, Vol. II, p. 14).

i/Excludes the value of the lost semi-submersible drilling rig (\$33.4 million 1987 dollars).

Control and cleanup costs also are affected by such considerations as the type of shoreline struck (e.g., sandy beach vs. rocky shore) and by the ease of accessibility of the resources employed in cleanup operations to the spill area. However, sufficient historic data do not exist to isolate the effect of these (and possibly other) factors on control and cleanup costs. Moreover, at the level of aggregation necessarily used in this document, it is not feasible to predict precisely the specific sections of areas that could be affected by a spill, should one occur. For these reasons, in the calculations made later, the only distinctions made when estimating cleanup and control costs for possible spills in the different OCS planning areas are: (1) whether or not the spill is expected to come ashore, (2) whether the source of the spill is an OCS production platform, pipeline, or a tanker, and (3) whether the spill is on the lower 48 OCS or the Alaskan OCS. No specific allowance is made for the influences of other factors on per barrel control and cleanup costs, except insofar as the use of an average from historic data implicitly reflects other determinants of cost. The per barrel cost of controlling and cleaning up oil spills used in the subsequent analysis of costs ranges from $326 for a spill coming ashore from an Alaskan OCS platform to $22 per barrel for an OCS-related tanker spill in the lower 48 which remains at sea (Table II.A.1.2).

2. Commercial Fisheries Losses

Direct Effects. Several types of losses could result should an oil spill occur and affect areas important to commercial fisheries. Spills which threaten fishing harbors can prevent vessels from leaving port for an extended period. Unless subsequent fishing effort yields returns sufficiently great to compensate for the lost fishing time, losses will be realized by the affected fishing fleet. If a spill strikes shore, the owners and employees of aquaculture, ocean ranching, or shellfish holding tank facilities could realize losses, although these losses can be reduced by defensive measures. Furthermore, costs arise if fishermen incur extra expenditures to remove oil coating vessel hulls and gear.

Costs also will be realized in open-sea fisheries if adult fish are damaged by the spill or if fish stocks are dispersed, thereby raising search costs. Long-term losses could occur if a spill damages susceptible eggs and larvae or coastal nursery areas, although these effects typically are difficult to assess because of the wide natural variations in fish stocks and the lack of definitive biological data.

Only direct commercial fisheries losses related to oil spills are considered here. Possible long-term effects on commercial fisheries caused by damages to lower trophic, non-commercial organisms or loss of wetland areas also could occur; these losses are considered later under potential ecological costs and value of lost wetlands. Potential losses to commercial fishing from at-sea physical space use conflicts with oil and gas facilities, and gear damage attributable to OCS-related debris, bottom obstructions and vessel operations are covered in later sections. Secondary (multiplier) effects are examined immediately following this section.

The most carefully documented economic analyses of the impact of oil spills on commercial fisheries are the studies of the Santa Barbara platform spill of 1969 and the supertanker AMOCO CADIZ oil spill of 1978. In the Santa Barbara spill, the loss of about 79 thousand barrels from



Table II.A.1.2. Summary of Per Barrel Oil Spill Control and Cleanup Costs Used in Analysis of OCS Planning Areas

| Spill Type | Cost per Barrel Lower 48 ($1987) | Cost per Barrel Alaskan OCS ($1987) a/ |
|---|---|---|
| Production Platform | | |
| Hits shore | 225b/ | 326 |
| Remains at sea | 102c/ | 149 |
| Pipeline | | |
| Hits shore | 222d/ | 309 |
| Remains at sea | 62d/ | 91 |
| Tanker | | |
| Hits shore | 228b/ | 351 |
| Remains at sea | 22e/ | 32 |

a/Unit cleanup and control costs for the Alaskan OCS are assumed to be 43 percent greater than indicated costs for lower 48 OCS spills, based on F.W. Dodge labor and materials construction cost index for Anchorage (L.A. McMahon, 1984 Dodge guide to Public Works and Heavy Construction Costs, 1983, p. XII).

b/Average of the cost of the relevant spills in Table II.A.1.1.

c/Estimate based on average per barrel well control costs for two production spills reported in Table II.A.1.1 ($81) plus the per barrel at-sea control and cleanup costs for the ARGO MERCHANT ($21).

d/Average of platform and tanker costs.

e/ARGO MERCHANT spill.

the Union Oil Co. platform threatened to pollute a nearby fishing harbor. The booms used to prevent the oil from entering the harbor precluded the 75 fishing vessels in the port from fishing for a period of two months. The estimated loss in returns on capital to the vessel owners and the loss in labor payments to the crews made unemployed amounted to $2.0 million (in 1987 dollars). Fishing vessel cleanup costs of $0.7 million also were incurred.

The 1.6 million barrels of oil lost in the AMOCO CADIZ spill polluted some 240 miles of the French coast. Over the 21-month post-spill period studied, the estimated loss to open-sea fisheries of $8.2 million in 1987 dollars was greatly exceeded by losses suffered by the area's major oyster culturing operators, $42.7 million (in 1987 dollars). Costs to the owners of large shellfish holding tanks affected by the spill totalled $4.6 million, and the cost of cleaning some 371 fishing vessels in the 13 ports affected by the oil spill was estimated to be $0.5 million (in 1987 dollars).

An important feature of both the Santa Barbara and the AMOCO CADIZ spills is that they took place close to land, and prevailing currents and winds combined to drive a considerable amount of the spilled oil to shore after only a brief period. Hence, relatively unweathered oil posed a considerable threat to fisheries and to fishing facilities. Damage to commercial fisheries from oil spills remaining at sea, however, are considerably less well documented. In fact, studies following the loss of 179 thousand barrels of #6 oil in the 1976 ARGO MERCHANT oil spill off Massachusetts were not able to identify any losses to commercial fishing as a result of the spill, although the possibility of long-term effects on commercial fisheries because of impacts on fish eggs and larvae and on the food web were recognized (Sherman and Busch, 1978, p.160)5/ A review of several oil spill case studies can be found in a recent National Academy of Sciences report (1985).

The per barrel cost (in 1987 dollars) to commercial fisheries of the AMOCO CADIZ ($34.0) and the Santa Barbara ($29.6) oil spills was approximately the same. However, the potential cost to commercial fisheries from oil spills in other OCS areas depends upon the value and characteristics of the fisheries concerned, the relative threat posed to fisheries by possible oil spills (the expected number of spills, their timing and trajectories), and other factors.

Recognizing that the risk to commercial fisheries varies across OCS areas, a basic loss-per-barrel-spilled figure of $32 is used (the rough average for the Santa Barbara and AMOCO CADIZ spills). However, this figure is adjusted by area based on the ratio of the value of landings in each area to the value of landings in the Santa Barbara planning area (Southern California). Thus, if an area has landings worth 20 percent more than Southern California, the loss-per-barrel-spilled for commercial fisheries for this area would be $38.4. Using this simplified approach, the cost-per-barrel spilled for commercial fisheries ranges from $150 for the North Atlantic to $8 for St. Matthew Hall (Table II.A.2.1). The use of this loss-per-barrel-spilled coefficient, multiplied by the expected amount of oil spillage in an area, provides the basis for the later measurement of direct commercial fishery losses for each area.6/

<u>Secondary Losses</u>. Secondary (multiplier) effects refer to the indirect losses in income that can result from an oil spill. As noted



Table II.A.2.1 Value of Commercial Fishery Landings By Planning Area and Estimated Loss Per Barrel Spilled

| Planning Area | Million $ (1983)a/ | Ratio of Area to So. Calif. | Loss per Barrel of Oil Spilled (1987)d/ |
|---|---|---|---|
| North Atlantic | 338 | 4.7 | 150 |
| Mid Atlantic | 325 | 4.5 | 144 |
| South Atlantic | 126 | 1.8 | 56 |
| Florida Straits | 50 | .7 | 22 |
| East Gulf of Mexico | 77 | 1.1 | 34 |
| Central Gulf of Mexico | 310 | 4.3 | 138 |
| West Gulf of Mexico | 177 | 2.5 | 79 |
| Southern California | 72 | 1.0 | 32 |
| Central California | 32 | .4 | 14 |
| Northern California | 29 | .4 | 13 |
| Washington-Oregon | 139 | 1.9 | 62 |
| Navarin Basin | 17b/ | .2 | 8 |
| Beaufort Sea | *b/,c/ | | *c/ |
| Chukchi Sea | *b/,c/ | | *c/ |
| St. George Basin | 12b/ | .2 | 5 |
| North Aleutian Basin | 115b/ | 1.7 | 54 |
| Gulf of Alaska | 106b/ | 2.1 | 57 |
| Shumagin | 21b/ | .3 | 9 |
| Norton Basin | 2b/ | *c/ | *c/ |
| Hope Basin | 1b/ | *c/ | *c/ |
| Kodiak | 60b/ | .8 | 27 |
| Cook Inlet | 28b/ | .4 | 12 |
| St. Matthew Hall | 8.6b/ | .1 | 4 |

Source:
a/U.S. Department of Commerce, National Marine Fisheries Service, <u>Fishery Statistics of the United States, 1983</u>, Washington, DC, April 1984, pp. 4-5. Reported state landings were allocated to conform to planning areas in some cases, based on landings by port.

b/The 1984 value of landings for these areas was estimated by allocating the region-specific landings reported in State of Alaska, <u>Alaska 1984 Catch and Production</u> (April, 1986) to each Alaskan OCS planning area. All 1984 dollars were converted to 1987 values.

c/* = less than one million dollars.

d/Product of $32 per barrel basic loss and the area-specific factor in column two.

previously, secondary effects may occur at the regional level but usually are not considered social costs; however, these effects may constitute social costs under some conditions. The commercial fishing industry appears to be particularly susceptible to secondary effects, especially in isolated areas with high unemployment rates or few alternate job possibilities. If a spill in such an area reduces the demand for fish, then the reduced derived demands for inputs to the region's fishing industry will cause an indirect social cost, if resources are thereby made idle or earn less. Indirect losses also can occur in forward markets, for example, if reduced fish landings due to a spill lead to unemployed labor and capital resources at processors, canners, or wholesale and retail facilities because substitute fish products are unavailable.

Estimation of secondary effects typically involves the application of an input-output, economic base, or other regional economic model (e.g., Grigalunas and Ascari, 1982; Rogers and Mayer, 1982; and King and Flagg, 1983). The size of the multipliers estimated with such a model depend upon the level of industry aggregation, the geographic region encompassed, and the base year(s) used for the study.

This report assumes that OCS-oil spill-related commercial fisheries losses in any planning area impose secondary regional and social costs. Representative results are used to characterize secondary effects from commercial fisheries losses; in each case when the available study presented more than one commercial fisheries multiplier estimate, the highest number was used. The resulting estimates of secondary effects range from \$89 to \$273 per \$100 direct loss in commercial fisheries (Table II.A.2.2). Hence, a commercial fishing industry income loss of \$100 due to an oil spill will result in an additional, secondary (indirect and induced) loss in income of from \$89 to \$273, depending upon the geographic region concerned.

3. Tourism and Recreation Losses

Tourism Industry Losses. If an oil spill occurs and comes ashore and affects the tourist season, losses could be realized by local hotels, other guest quarters, transportation-related firms, restaurants, retail and other establishments that cater to tourists, and to residents engaged in similar recreational activities. This combination of businesses is collectively referred to as the tourist industry.

Local tourist industry losses are measured by the reduced profits--not expenditures--realized by owners and by the lower earnings of employees because of the spill, allowing for the influence of weather and other factors which also can affect the tourist industry. Further, the estimated loss in profits from reduced tourism should be net of any beneficial effects resulting from expenditures made by research and media personnel and curious onlookers who typically visit an area following an environmental incident.

A particular locale's tourism industry can suffer serious losses from a spill. However, from an aggregate perspective, it is likely that the tourism industry losses in one location will largely be offset by gains at other, unpolluted substitute sites within the same planning area to which tourists are diverted. Evidence from the Santa Barbara spill (Mead and Sorensen, 1970, pp. 194-202) supports this tourist-diversion argument.



Table II.A.2.2 Secondary Income Losses (in 1987 dollars) Resulting From a \$100 Loss in Commercial Fishing Income a/

| Region | Loss |
|---|---|
| Atlantic | \$ 94b/ |
| Gulf of Mexico | 89c/ |
| West Coast | 273d/ |
| Alaska | 121e/ |

a/Secondary losses measure the indirect and induced income losses for each \$100 direct loss in income.

b/Grigalunas and Ascari (1982, p. 29).

c/Lamphear and Restrepo (1982, Appendix A).

d/King and Flagg (1982, p. 67).

e/Rogers and Mayer (1982, p. 98).

When tourism industry gains and losses offset one another within a planning area following an oil spill, neither social costs nor regional costs are incurred. However, it is possible that the adverse publicity which can be expected when an oil spill strikes beaches in one OCS area could divert tourists to another area. For example, an estimated 245 thousand tourists who were expected to visit Brittany's beaches in the summer of 1978 instead went elsewhere following the AMOCO CADIZ spill, although poor weather may have been a contributing factor to the region's tourism industry losses (Grigalunas et al., 1983).

To allow for possible regional tourism industry losses for OCS planning areas, we use the results of the AMOCO CADIZ study, which was perhaps the most comprehensive study of oil spill costs. The results of this study indicate that the Brittany region suffered net tourism industry losses and associated secondary (multiplier) losses of about 0.9 dollars per one dollar of non-market value recreation losses to the nation as a whole (Grigalunas, 1983, p. 183). This result is used in the sections which follow to approximate direct and secondary regional tourism industry losses.

Estimated regional tourism industry losses using this approach are believed to be overstated for two reasons. First, OCS-related oil spills which occur and come ashore may be cleaned up quickly or, in fact, may occur during the non-tourist season. Second, the non-market valued recreation loss (described below) used as the base to estimate tourism industry losses itself is a conservative (i.e., high) estimate. It also should be noted that the owners and operators of establishments suffering tourism industry losses caused by OCS-related oil spills are eligible for compensation for damages from the OCS facility operator or from the Oil Spill Pollution Fund, as provided for by Sec. 303 of the OSCLA. Hence, compensation for damages will reduce the costs of an oil spill initially realized by the tourism industry within an OCS area.

<u>Non-Market Valued Losses to Recreationists</u>. Two types of non-market recreational losses are allowed for in this analysis. First, losses occur when individuals' enjoyment of ocean-oriented recreational experiences is reduced because a beach environment is polluted with oil, or because they incur additional costs to visit a non-polluted, substitute recreational site. Second, if people affected by a spill visit a substitute beach (or other recreational facility) congestion losses caused by crowding may be realized at the substitute location. In both cases, it is noted that only losses in satisfaction to individual recreational participants are considered here; losses suffered by the owners and employees of tourism businesses were covered in the preceding section under the heading of tourism industry losses.

Because losses in the value of the recreational experience are not directly observable through the market, estimation approaches involving the use of surveys or other extra-market approaches must be used. The travel cost, willingness-to-pay (or sell) and other techniques all are potentially applicable to the estimation of non-market recreational losses from oil spills (see Freeman, 1979). However, these techniques rarely have been applied to estimate recreational losses from oil spills. This is because so few large spills have occurred and affected recreational beaches and because in the past, researchers were unable to respond quickly to those few spills which did take place and impact the shoreline.



Although a considerable number of studies have examined the non-market evaluation of recreation in general and marine recreation in particular, only two estimates of non-market value losses to recreationists have been made following oil spills. Mead and Sorensen estimated losses to recreationists following the Santa Barbara oil spill. As noted, this OCS platform spill involved the loss of about 79 thousand barrels of oil over a two-month period, affecting some 30 miles of shoreline. Attempts were made to elicit the value of beach use by asking a sample of residents to equate the value of the beach experience to an activity with an established price (a movie). They estimated total losses to recreationists of $9.5 million, which is equivalent to $121 per barrel of oil spilled (in 1987 dollars).

The 1.6 million barrels of oil lost in the March, 1978 AMOCO CADIZ spill polluted some 240 miles of beaches in Brittany, the second most popular summer ocean vacation location in France. Losses were estimated for tourists and residents (1) who avoided the area because of the spill and (2) who came to, or remained in, the region but enjoyed themselves less or modified their activities because of the spill. The estimated total loss in recreationists' satisfaction in 1987 dollars ranged from $22.8 to $144.1 million, depending on the technique and assumptions used to evaluate losses (Brown, 1983, p. 106). These results imply non-market valued recreational losses of from $14.2 to $90.0 per barrel spilled (or about $52.0 to $328.4 per barrel coming ashore) for this incident in 1987 dollars.

In addition to the studies cited above, two recent analyses describe the effects of oil spills on beach use. Freeman, Holland and Ditton (1985) found that predicted negative impacts of the 1979 IXTOC I spill on coastal Texas park visitation could not be substantiated. They concluded that most of the impact of the spill was due to disruption in gasoline availability (p. 23).7/ However, the authors acknowledge that they only studied visitation; possible effects of the spill on the quality of visitors' recreational experiences were not considered (p. 23). Using data from the Texas Parks and Wildlife Department, a David M. Dorbusch & Co. study reported some 108 thousand fewer visitors to Galveston Island State Park in the two month period following the August 3, 1984, ALVENUS oil spill (1985, p. 8). Unfortunately, no economic analysis was made of the costs of this spill. For this reason, it is not possible to use the information given to assess the economic loss to recreationists resulting from the decrease in beach use because of the ALVENUS oil spill.

In addition to the above case studies, Wilman (1984) has simulated the recreational losses which could result from hypothetical 1,000 and 37,500 barrel oil spills coming ashore on Cape Cod from assumed Georges Bank OCS oil operations. Her analysis is based on the hedonic approach, which attempts to place implicit values on particular coastal recreation attributes.

The Wilman analysis uses a number of alternative assumptions to generate a wide range of estimates of possible recreation losses. In adapting her results for this analysis, we use the average of the estimated losses for the four highest cases for which she assumes that (1) spilled oil degrades at 50 percent per year; and (2) damages increase in real terms at 7 percent annually (1984, p. 139). The recreational losses using these assumptions amount to $538 per barrel in 1987 dollars.8/

Mindfull of the many difficult issues inherent in any attempt to assess potential non-market value recreational losses from an oil spill in a particular case, a simplified approach is adopted to provide some perspective on the possible magnitude of these losses across OCS planning areas. First, each OCS area is assigned to a category reflecting the relative threat believed to be posed to recreation in the area from OCS production and transportation. This information is presented in Table II.A.3.1. Second, each planning area is assigned a dollar figure reflecting a judgmental loss in non-market recreational values per barrel spilled and coming ashore. The precise dollar figure corresponds to the degree of threat posed to the area. This figure ranges from $538 per barrel spilled and coming ashore for high risk areas--the average of Wilman's large oil spill cases described above--to $134 per barrel for the low risk areas. The moderate-to-high risk case is $269 per barrel. Hence, the moderate-to-high and the low risk areas are assigned values which are, respectively, one-half and one- fourth of the high per barrel loss value used for high risk areas. Given the much lower recreational loss estimates found in actual case studies of oil spills, given the much lower estimates found in the Wilman study itself (but not used in this analysis), and given the fact that spilled oil which does come ashore may do so in a non-tourist season (or may not strike a beach), the per barrel estimates of recreation losses used here are believed to overstate these losses substantially.

The second type of non-market value recreation loss concerns possible congestion effects (see, e.g., McConnell, 1977). As noted previously in this section, should an oil spill cause prospective beach goers to visit a substitute site, users of that site may enjoy the recreational experience less because of the additional crowding. Although there are no studies available that measure the congestion effects which could arise when recreationists are diverted from a site affected by a spill to a substitute, unpolluted location, the concept of congestion effects is recognized in the literature. For example, in his study of Rhode Island beaches McConnell estimated that an extra 100 people per acre on the average beach reduced the average individual's satisfaction (measured by consumer surplus) by about 25 percent (1977, p.191). Since it is conceivable that congestion effects could arise in particular cases (e.g., a spill affecting intensively used recreational beaches during the peak season) an allowance is made for this possibility.

Clearly, the potential significance of congestion effects in any particular case would depend upon several factors: The size, season and location of the spill; the extent to which people are diverted to substitute sites; the utilization and capacity at the substitute sites and the preferences of individuals at those sites for solitude. The many uncertainties associated with the possible size, timing and location of possible oil spills, the lack of prior studies in this area and the difficulties involved with establishing congestion effects require that a simplified approach be used if any consideration is to be given to this type of potential social cost. To allow for possible congestion effects, in the calculations which follow the base per barrel non-market value recreation losses for each area described earlier in this section are increased by 25 percent (Table II.A.3.1).



Table II.A.3.1 Risk Categories and Per Barrel Loss Figures for Non-Market Valued Losses to Recreationists by OCS Planning Areas

| Risk Category | OCS Area | Base Loss Per Barrel Spilled and Reaching Shore a/ | Congestion Loss at Substitute Site b/ | Total Loss/BBL Spilled and Reaching Shore |
|---|---|---|---|---|
| Moderate to High: | Atlantic | $538 | 135 | 673 |
| | Gulf of Mexico | 538 | 135 | 673 |
| | Pacific | 538 | 135 | 673 |
| Low to Moderate: | Cook Inlet | 270 | 68 | 338 |
| | Gulf of Alaska | 270 | 68 | 338 |
| Negligible to Low: | Rest of Alaska | 135 | 34 | 169 |

a/See text for a discussion of the development of the per barrel loss estimates.

b/Assumed to be 25 percent of base loss per barrel.

Actual non-market valued losses depend on whether or not spilled oil comes ashore. Hence, in the calculations made later, the amount of spilled oil expected to reach land for each planning area is a key piece of information used to assess possible non-market value recreational losses across OCS planning areas.

4. Ecological Costs

Ecological costs are among the most difficult potential costs of an oil spill to quantify in economic terms. To estimate potential ecological costs it is necessary to ascertain the extent of specific biological losses and then to assign an economic value to these losses. Since most of the organisms affected by a spill are not directly consumed or otherwise exchanged in markets or used for viewing, establishing an economic value becomes problematical.

Various conceptual approaches exist, in principle, for evaluating the economic cost of ecological losses following a spill (e.g., food web models, replacement cost, and surveys using willingness to pay or sell techniques). However, in practice the state of the art, and the uncertainties typically involved, are such that rarely can economically defensible estimates of ecological damages be made with confidence (Brown, 1983, pp.81-82). For these reasons, administratively- or legally-determined values, and not economically-based measures, are usually employed to set the ecological damages of oil spills.9/

The discussion of potential ecological costs draws on the results of two case studies, the AMOCO CADIZ oil spill, described earlier, and the 1973 ZOE COLCOTRONI spill. The assessments of ecological costs in these studies are the most frequently cited and the best documented such analyses available and hence are the most relevant sources for the present effort.

In the AMOCO CADIZ spill, an estimated sixty million marine organisms were killed (Chasse, 1979). Although it was not possible to develop estimates of ecological costs based on established economic principles, the use of unit values employed by a local biological station which sold some of the species impacted by the spill, and the adoption of a unit value used by the State of California to place a dollar value on organisms in the environment killed by oil spills, resulted in estimated ecological costs of \$66.8 million and \$26.4 million, respectively (Brown, 1983, p. 82). Hence the per barrel cost is \$41.6 or \$16.5 (in 1987 dollars), if one accepts this approach for assessing ecological costs.

In the ZOE COLCOTRONI incident, the 36 thousand barrels lost severely polluted the shoreline and some twenty acres of mangrove forest in Bahia Sucia, Puerto Rico. Replacing the dead and damaged mangroves (replanting, monitoring, and fertilizer costs) cost an estimated \$1.1 million. In addition, the use of the lowest unit price from the catalogues of firms which market biological supplies similar to those destroyed in the spill resulted in an estimate of the replacement cost of the 92.1 million marine animals lost to the environment of \$10.4 million (Sorensen, 1977).10/ Thus, the total estimated cost per barrel spilled in this case amounted to \$319 (in 1987 dollars), if one assents to the use of catalogue prices (vs. in situ values) to assess the economic loss of organisms in the marine environment.



Potential ecological costs are presumed to be greater than zero, but the state-of-the-art simply does not currently allow economically defensible estimates of these potential damages to be derived in most cases. Faced with the wide divergence in estimated ecological costs obtained when use is made of one or another administratively-determined rule, the present analysis adopts the results of past studies, adjusting them to reflect the relative marine productivity and environmental sensitivity of the different OCS planning areas (see Appendix I). The planning area with lowest productivity and environmental sensitivity score is assigned a unit ecological loss of \$41.7 per barrel of oil spilled, while the area with the highest score are assigned a loss value of \$319.6 per barrel spilled, the highest per barrel cost cited.11/ Areas of intermediate productivity and sensitivity are given intermediate sensitivity values, based on their productivity and sensitivity score.

Table II.A.4.1 summarizes the ecological loss value per barrel of spilled oil for each planning area used in subsequent calculations, based on the approach outlined above. It is noted that the low available ecological loss values of \$16.4 per barrel in the AMOCO CADIZ case is not used, nor is any distinction made for spilled oil which remains at sea (and thereby generally results in lower potential ecological costs than oil affecting the coastal environment). If these considerations were to be included in Table II.A.4.1 and in subsequent calculations, the estimated potential ecological costs would be lower than with the adopted approach.

5. Subsistence losses

Subsistence is an important, and in some cases a predominant, way of life in a number of planning areas in Alaska. In specific cases, subsistence harvesting of marine mammals, fish, sea birds and eggs, and other marine and land animals and plants account for as much as 80 percent of a community's diet (Little and Robbins, 1984, p. 29). In addition, purchases made in the cash economy are often made feasible through the use of the proceeds from the sale of harvests and artisanal craft items such as ivory carvings and skin and fur garments utilizing the by-products of subsistence harvesting.

OCS oil and gas operations are viewed by some Native Alaskans as imposing a risk to subsistence communities in addition to the risks of severe weather and fluctuations in the stocks of particular species traditionally faced by these communities. Marine mammals and fish could be damaged or killed, should OCS operations result in air or water pollution which significantly affects area habitats. Noise and visual pollution and water and air pollution could cause species to leave their habitats and/or alter their migratory routes, thereby imposing costs on native communities (Little and Robbins, 1984, pp. 333-334).

According to Little and Robbins, the effects of a decline in major subsistence resources from OCS oil and gas operations or other sources on the community they studied would depend upon a variety of factors:

> If only one or a few species were affected, it might be possible for islanders to intensify hunting efforts for the unaffected species in an attempt to replace reduced or lost resources. The success of such alternative hunting strategies would be determined by the magnitude of the disruption, the number of species affected,

Table II.A.4.1 Relative Marine Productivity and Environmental Sensitivity and Assigned Ecological Cost Per Barrel Spilled for OCS Planning Areas (in 1987 dollars)

| Planning Area | Relative Marine Productivity and Environmental Sensitivity Scorea/ | Ecological Cost per Barrel Spilledb/ |
|---|---|---|
| North Atlantic | 209 | $132.5 |
| Mid-Atlantic Areas | 198 | 117.8 |
| South Atlantic | 230 | 160.6 |
| Straits of Florida | 246 | 181.9 |
| Eastern Gulf of Mexico | 189 | 105.8 |
| Central Gulf of Mexico | 254 | 192.7 |
| Western Gulf of Mexico | 180 | 93.8 |
| Southern California | 211 | 135.2 |
| Central California | 229 | 159.3 |
| Northern California | 232 | 163.3 |
| Washington-Oregon | 256 | 195.3 |
| Gulf of Alaska | 235 | 167.3 |
| Kodiak | 264 | 206.0 |
| Cook | 272 | 216.7 |
| Shumagin | 265 | 207.4 |
| No. Aleutian | 327 | 290.2 |
| St. Georges Basin | 281 | 228.7 |
| Navarin Basin | 141 | 41.7 |
| Norton Basin | 280 | 227.4 |
| Hope Basin | 349 | 319.7 |
| Chukchi Sea | 204 | 125.9 |
| Beaufort Sea | 261 | 202.0 |

a/Source: U.S. Department of Interior, Secretarial Issues Document, 1986 Proposed Five-Year Lease Schedule, Appendix I, Table I.5.

b/Source: See text for a discussion of the development of per barrel ecological cost estimates. Per barrel cost values were assigned to each area using the formula: area cost/bbl = 41.7 + 1.336 (area score - 141).



the availability of alternative species, the season of the year, the volume of stored subsistence products, the length of the disruption and a host of other factors. Clearly, a reduction in the bird population would not pose the physical threat that the reduction in the walrus herd would. A 10 percent reduction in the seal population is less serious than a 90 percent reduction. Finally, a less than catastrophic reduction in the winter walrus herd is more significant than an equal reduction in the spring walrus herd.

In addition to harvest disruptions, other types of subsistence losses can occur. An influx of workers who pursue recreational fishing and hunting could lead to competition with members of native communities for stocks of salmon and halibut and other fishery and wildlife resources.

It is recognized that standard economic concepts may have little applicability in assessing the consequences of OCS oil and gas operations on native cultures dominated by values of kinship, sharing and community (Jorgensen et al., 1984; Little and Robbins, 1984). Nonetheless, there are limited aspects of subsistence lifestyles where economic values may have some relevance. To provide some perspective on possible subsistence losses which could result from oil spills, it is presumed that should an oil spill disrupt the fishery harvest of a subsistence community, these resources would have to be replaced for consumption or income purposes. These possible subsistence losses are valued based on the estimated loss of commercial fish per barrel of oil spilled for coastal Alaskan OCS planning areas presented in Table II.A.2.1. However, as indicated in this table some of the Alaskan OCS areas, e.g., the Chukchi Sea, show negligible commercial fishery landings (i.e., less than one million dollars), which would imply zero subsistence losses using the approach suggested here. To avoid the implicit assumption of zero subsistence losses from oil spills in these areas, it is assumed in the calculations of social and regional costs which follow that the subsistence loss per barrel of oil spilled for all coastal Alaskan OCS planning areas is twice the estimated commercial fishing loss per barrel for the Alaskan OCS area with the highest commercial fishing loss per barrel, the Gulf of Alaska (see Table II.A.2.1). The estimated loss to commercial fisheries in this area per barrel of oil spilled is $67. Hence, for all coastal Alaskan OCS planning areas, each barrel of oil spilled within that area is assumed to result in $134 of subsistence losses.12/

Other types of losses in subsistence areas, such as ecological costs, are included in other sections of this appendix. The important non-economic aspects of possible disruptions to subsistence communities caused by OCS oil and gas operations are reviewed in the EIS accompanying the proposed five-year lease schedule and are examined in sale-specific EIS's.

6. Value of the Lost Oil

The market value of the oil spilled, less the net value of oil recovered and sold, is the correct measure of this cost. For each planning area, market value is measured by the landed price of imported oil of the same quality (specific gravity and sulfur content) as the OCS oil spilled.

For purposes of this analysis, a starting price of $29 per barrel is used to value oil spilled in all OCS planning areas. The price of oil is assumed to increase one percent annually in real terms. The $29 starting price for oil corresponds to the high initial price assumption being used in the estimation of the economic benefits of OCS hydrocarbon development in other sections of the analysis of the proposed five-year OCS leasing schedule. No allowance is made for the value of recovered oil, which overstates this cost somewhat.

7. Other Costs

This miscellaneous category encompasses legal-administrative costs, research costs, and losses in property values which could arise as a result of OCS-related oil spills.

Legal-Administrative Costs. The social costs of OCS-related oil spills include the opportunity costs of the additional resources used for legal purposes as a consequence of the spills. The costs of administrative and judicial proceedings could be measured, in principle, by the amounts paid to attorneys and experts, the value of time spent by the parties involved, and any amounts spent in excess of normal expenditures.

Determination of liability and damages is a complex and time-consuming process, and legal costs can be considerable. Legal costs of $18 per barrel spilled (in 1987 dollars) are documented for the 1976 STC-101 Chesapeake Bay oil spill (Hughes, 1982, p. 65), but little other useful information exists concerning legal costs because of the proprietary nature of these costs.

For this analysis, legal-administrative costs of $18 per barrel are assumed for all spills. Use of an estimate which is one-half of the cost per barrel of the STC-101 spill likely results in an overstated estimate of these costs because: (1) strict liability established under the OCSLA (Sec. 303) significantly reduces the legal-administrative costs of OCS-related oil spills and (2) spills remaining at sea and the vast majority of small spills can reasonably be expected to involve fewer (conceivably no) contestable claims for damages and hence are unlikely to result in legal-administrative settlement costs.

Research costs. The cost of studying the fate and effects of spilled oil, and of establishing biological, economic, and other damages, can be considerable. In the AMOCO CADIZ case, research costs (in 1987 dollars) amounted to $6.6 million or $4.11 per barrel spilled (U.S. Dept. of Commerce, 1983, p. 132-3). Research costs of about $8 (in 1987 dollars) per barrel were reported for the ARGO MERCHANT oil spill (U.S. General Accounting Office, 1977, pp. 7-9).

The analysis which follows is based on the assumption that research costs per barrel amount to $8 for large OCS spills. This value probably overstates these costs because: (1) the benefits of new basic knowledge produced by the research are not netted out, and (2) both the AMOCO CADIZ and the ARGO MERCHANT spills were subject to particularly intensive research scrutiny because of world-wide interest.

Property value loss. If the threat of oil spills causes shoreline property values to decline--after allowing for the influence of all other



determinants of property values--the loss can be treated as a cost of proposed OCS lease sales. An analysis of this issue following the Santa Barbara oil spill suggested that property values fell by $3.5 million (in 1987 dollars) (Mead and Sorensen, 1970, p.225). However, no property value losses were detected in the aftermath of the 1978 AMOCO CADIZ spill (Sorensen, 1983, p. 77). Using the results for Santa Barbara (in 1987 dollars), property value losses of $45.5 per barrel are assumed for spilled oil coming ashore in the lower 48 states. A nominal figure of $5.10 per barrel coming ashore is used for Alaskan OCS areas because of their lower intensity of coastal development. The coefficient used to estimate property value losses likely overstates these costs because spills generally are viewed as accidental, transitory events.

B. Estimates of Potential Non-Oil Spill Costs

1. Air Quality Losses

OCS production, processing, loading and unloading, storage and transport activities generate several types of discharges into the atmosphere. If incremental air emissions from OCS operations contribute to a deterioration in ambient air quality exceeding damage-threshold levels, economic costs will be imposed.

Measurement of air quality losses from OCS operations in principle involve the same methodological considerations and analytical steps associated with the measurement of damages from oil spills. To link OCS oil and gas activity and economic costs, one must relate the level of OCS operations to emissions, emissions to ambient air quality, air quality to physical damages, and the latter to economic costs. Spatial and seasonal factors further complicate attempts to evaluate air pollution costs.

The information used to provide a measure of possible OCS oil and gas air pollution costs draws upon the results of a 1979 CTARP study of OCS oil and gas activity off the coast of Southern California (U.S. Dept. of Commerce, NOAA, 1979). This research is particularly useful for the present analysis because (1) the study specifically deals with air pollution from OCS oil and gas operations, (2) its concern is with quantification of economic effects, (3) the geographic area studied, Southern California, faces the most severe air pollution problems among all OCS areas, and (4) the results are documented in some detail.

Using data from the proposed OCS lease sale #48 as a case study, the CTARP study estimated air quality losses of $0.036 per barrel of oil and $0.014 per thousand cubic feet of natural gas (in 1979 dollars) (NOAA, 1979, p. 201). The major potential cost of OCS oil and gas-related air quality losses was to health.

Regulations in effect since 1980 require firms to use the best available control technology (BACT) or to employ offsets in order to avoid exceeding air quality significance levels. Hence, use of the emissions rates in the CTARP study, which was published prior to the adoption of present air quality regulations, would considerably overstate possible air quality losses from leasing resources beginning in 1986. A 1981 monitoring study of eight OCS facilities in Southern California and thirteen facilities in the Central Gulf of Mexico indicates that actual air emission rates are far less than the pre-regulation rates projected in the CTARP study (Baer, 1984, personal communication). Using the ratio of actual emissions from this monitoring work to the projected emissions from the CTARP study to adjust the CTARP economic loss estimates results in an estimate of air quality losses of $0.0195 per BOE for Southern California and about one-half of this amount ($0.0059 per BOE) for the Central Gulf of Mexico (Winnor, 1985, personal communication). These figures are used in the subsequent analysis of potential social costs. Air quality losses for other OCS areas are expected to be negligible; a nominal figure of $0.00298 per BOE (one-half the Central Gulf of Mexico unit cost) has been assumed.13/

These figures provide some perspective on air quality losses which could result from OCS operations. It must be recognized, however, that they may provide conservative cost estimates because future oil and gas operations will take place considerable distances from shore and effective air quality regulations can mitigate these potential losses.

2. Wetland Losses

Development of offshore oil and gas requires onshore support and transport facilities which can lead to wetlands losses. Dredging of pipeline or navigation canals can block or channelize water flows, thereby altering water circulation patterns. This can result in changes in water tables, tidal flows, and salinity levels, all of which can be detrimental to wetland habitats. Construction activity can lead to soil compaction and subsequent loss in water holding capacity of the wetland's soil. If these soils are not restored to preconstruction conditions, long-term changes in water quality, groundwater levels, and vegetation can result. OCS oil and gas-related activities have been cited as one of the contributing factors to salinity changes and loss of wetlands, most notably in Louisiana, although the available results do not indicate the share of wetland alterations attributable to OCS oil and gas operations vs. oil and gas operations in state waters and other activities (OLDS, 1984).

Wetlands are recognized as important nurseries and food production areas for many species of finfish, shellfish, and waterfowl. Wetlands work as buffers for flood waters and can reduce levels of erosion and subsequent sedimentation. Also, wetlands provide aesthetic benefits through provision of open space and may play important roles in purifying waters by removing excess nutrients and reoxygenating water. The essentially irreversible nature of damages resulting from wetland losses and the relatively increasing value of these natural environments (compared to manufactured goods) has been recognized in the economics literature (see, e.g., Shabman and Bertelson, 1979).

While it is easy to enumerate benefits provided, quantification of economic damages from wetland losses, particularly preservation value, is extremely difficult because the flows of services provided by these resources are not directly measurable through the market. Past studies have employed the "life support" measure of Gosselink et al. (1974), largely because alternative measures which capture the diversity of benefits from wetlands were unavailable. The life support approach estimates total primary energy production within the wetland of interest and multiplies this measure of energy by a unit value determined by dividing Gross National Product by the National Energy Consumption index. However, this life support measure of value has been severely criticized as having no meaningful relationship to standard measures of value



(Walker, 1974; Shabman and Batie, 1978; Shabman and Bertelson, 1979). For example, Shabman and Batie show that the life support methodology implies a value for Virginia hay land of $6,960 per acre (in 1974 dollars), while the average price of farmland in Virginia was $556 per acre in 1974. Hence, even in cases where all services of land are captured by the owner, the life support methodology of Gosselink et al may vastly overstate the land values.

Despite severe empirical problems, numerous recent studies have attempted to measure the value of various services provided by wetlands. Several studies have sought to estimate the economic contribution of wetlands to particular fisheries (Batie and Wilson, 1979; Lynn et al., 1981), as well as overall economic returns to commercial fisheries in several estuary areas (Tihansky and Meade, 1976). Value of wetlands for wildlife management, flood control, and amenity benefits have been estimated (Gupta and Foster, 1975). Also, hedonic analysis has been used to isolate the effect of the amenity qualities of salt ponds on property values (Edwards and Anderson, 1984). Finally, estimates are available for the value of a recreation fishing day (e.g., Norton, Smith, and Strand, 1983).

Attempts to estimate the possible economic damages from wetlands changes resulting from the expansion of OCS oil and gas operations in a planning area must relate the anticipated increase in exploration, development, production and transportation to (1) investment in pipelines and onshore support facilities, (2) acres of wetlands destroyed, and (3) economic damages. Analysis of this issue is further complicated because the investment in pipelines and other facilities needed to support proposed OCS operations depends on the rate of utilization of existing facilities and on a host of highly area-specific siting issues which can be substantially influenced by applicable state and federal rules and permitting requirements.

Given these considerations, the wetlands acreage losses for each area were estimated using the best judgment of experts within Department of the Interior. In areas with negligible or zero estimated resources, zero acreage loss is assumed. For other areas, acreage losses were allocated over time, assuming constant acreage damaged per year, starting from the lease date and culminating at the year of peak production. In addition, erosion is assumed to cause wetland damages to spread each year at a rate of 5% of the cumulative damages to date, again achieving total damages at the year of peak production.

The value per acre of wetlands is estimated by summing the estimated value of preservation benefits for each region using the economic information described above. The aesthetic and flood control benefits are taken from Gupta and Foster (1975). These values are $270 and $80 respectively (in 1972 dollars) per acre each year. These figures imply a capitalized value per acre of $11,557 (in 1987 dollars) at an 8% rate of interest.

Wildlife values per acre of wetland are estimated using area specific information on the range of per acre prices or assessed values made by Fish and Wildlife Service in acquiring wetlands acreage in each area. These per acre value ranges are given in Table II.B.2.1. This study employs the mid-point of the range of values for each region outside of Alaska as an estimate of wildlife values. Within Alaska,

Table II.B.2.1. Wildlife Valuation Per Acre

| | Fish and Wildlife Service Range | Wildlife Value Per Acre |
|---|---|---|
| CGOM | 50- 250 | 150 |
| WESTGOM | 450- 500 | 475 |
| S.CALIF | 300- 1000 | 650 |
| S.ATLAN | 50- 100 | 75 |
| NAVARIN | N.A. | 50 |
| EASTGOM | 0- 50 | 25 |
| BEAUFRT | N.A. | 50 |
| CHUKCHI | N.A. | 50 |
| CEN.CALIF | 300- 1000 | 650 |
| N.CALIF | 300- 1000 | 650 |
| ST.GEORGE | N.A. | 50 |
| MID-ATLAN | 400- 2000 | 1250 |
| N.ATLAN | 600- 1500 | 1050 |
| ORE/WASH | 300- 1000 | 650 |
| N.ALEUTIAN | N.A. | 50 |
| GULFALASKA | N.A. | 50 |
| NORTON | N.A. | 50 |
| KODIAK | N.A. | 50 |
| HOPE | N.A. | 50 |
| SHUMAGIN | N.A. | 50 |
| COOK INLET | N.A. | 50 |
| STR OF FLORI | 50- 50 | 50 |



where these figures are unavailable and wildlife habitat is abundant, the lowest non zero figure of $50 per acre is used.

The value of wetlands as nurseries for recreational and commercial fisheries is calculated as follows. Availability of wetlands is assumed to be a limiting factor for all fisheries. The proportion of fisheries losses is assumed to be equal to the proportion of wetlands destroyed. Fisheries losses are then calculated by multiplying the total value of the fishery by the proportion of total available wetland which is destroyed by onshore development. For example, the proportion of wetlands lost in the Western Gulf of Mexico is calculated by dividing wetland acreage losses (400 acres, including erosion) by total esturine wetlands in the region (1.715 million acres) to calculate the proportion of wetlands which are destroyed. The total value of a commercial fishery's catch is then multiplied by this figure to determine the loss in commercial fisheries. For recreational fisheries, the total number of recreational fishing days is obtained for each area (U.S. Dept. of Commerce, National Marine Fisheries Service, 1984, p. 20).14/ This is multiplied by an estimate of the marginal value of a recreational fishing trip for striped bass from Norton, Smith and Strand (1983). Norton et al. give values ranging to a maximum of $12.63 for recreational fishing days in various areas on the Atlantic coast. For this section, the highest marginal value per day is used. Adjusted to 1987 dollars, this value is $15.45 per day fished. In the Western Gulf, the annual value of an acre of wetlands for recreational fishing is $15.03/day fished times 7.372 million days fished divided by total acres of wetlands (1.715 million) equals $66.41. At an 8% interest rate, this implies a capitalized value of $830 per acre. The value per acre for commercial fisheries is total value of catch in 1987 dollars ($229.9 million) divided by 1.715 million total acreage equals $134.00. At an 8% interest rate, this implies a capitalized value of $1675. Hence, the value of an acre of wetlands in the Western Gulf as a nursery ground for commercial and recreational fishing is $2506.

The total capitalized value of an acre of wetland in the Western Gulf is the sum of the aesthetic, wildlife, and flood control benefits ($12,046) plus the value as nursery grounds for commercial and recreational fisheries ($2506), which equals $14,270 per acre. Determining acreage damaged as described above, the total present value of (in 1987 dollars) of wetland losses in the Western Gulf is $2.58 million.

These measures are expected to overstate fisheries losses since many species, such as tuna and sea scallops, are not highly dependent upon wetlands. In addition, wetlands availability may not be a limiting factor even for those species which do depend upon wetlands. For example, Batie and Wilson (1979) and Lynn et al. (1981) both conclude that the loss of a small amount of wetlands would not likely have much of an effect on particular wetlands-dependent fish populations. Finally, these figures represent gross value of recreational and commercial fishing from which costs of fishing should be deducted to calculate net values.

Using the methodology described above, acres of wetlands lost, value per acre of wetland and total economic losses were estimated for each region (Table II.B.2.2). As shown in the table, acres lost range from near zero to about 1013 acres. The value per acre ranges from about

Table II.B.2.2. Estimated Wetland Losses for Each OCS Planning Area Resulting From the Production of all Leasable Resources Unleased as of mid 1987
($29 per barrel oil starting price)

| Area | Acres Lost | Value Per Acre | Present Value |
|---|---|---|---|
| CGOM | 1013 | 13847 | 6.73 |
| WESTGOM | 408 | 14270 | 2.58 |
| S.CALIF | 41 | 24610 | 0.62 |
| S.ATLAN | 84 | 12826 | 0.63 |
| NAVARIN | 112 | 11649 | 0.77 |
| EASTGOM | 216 | 12110 | 1.07 |
| BEAUFRT | 173 | 11611 | 1.13 |
| CHUKCHI | 0 | 11610 | 0.00 |
| CEN.CALIF | 41 | 20898 | 0.52 |
| N.CALIF | 41 | 58280 | 1.46 |
| ST.GEORGE | 112 | 11637 | 0.77 |
| MID-ATLAN | 34 | 15059 | 0.31 |
| N.ATLAN | 30 | 28545 | 0.45 |
| ORE/WASH | 0 | 26381 | 0.00 |
| N.ALEUTIAN | 0 | 11871 | 0.00 |
| GULFALASKA | 0 | 11852 | 0.00 |
| NORTON | 0 | 11615 | 0.00 |
| KODIAK | 0 | 11747 | 0.00 |
| HOPE | 0 | 11612 | 0.00 |
| SHUMAGIN | 0 | 11658 | 0.00 |
| COOK INLET | 0 | 11677 | 0.00 |
| STR OF FLORI | 43 | 12468 | 0.30 |



$11,610 to $58,280. The net present value of losses range across regions from near zero to about $6.7 million.

A similar approach was used by Costanza and Farber (1985) in valuing the productivity of Louisiana coastal wetlands. Costanza and Farber estimated the value of wetlands in providing services which contribute to trapping, commercial fisheries, various recreational activities, and storm protection. Commerial fisheries considered include menhaden, oysters, blue crab, as well as brown and white shrimp (inshore and offshore). Recreational value was determined using the travel cost method, with data collected in the form of a survey which was distributed to a random sample of individuals at various boat launch sites in the wetlands area. Hurricane protection service of wetlands was determined by calculating the predicted increase in damage which would occur from being closer to the landfall of a hurricane.

A summary of the annual and net present value per acre for each of these services is contained in Table II.B.2.3. The total net present value from all sources in the Costanza and Farber study is $2,429. Since this value is less than the minimum value of wetlands for any region discussed above, this report uses the conservative (i.e., high cost) results contained in Table II.B.2.2.

3. Commercial Fishing Area Preemption and Gear Losses

Area Preemption Losses. The emplacement of substantial numbers of OCS production facilities, pipelines and pumping stations in important commercial fishing grounds will preclude fishing in affected locations and could decrease catch per unit effort and lower fishermen's net earnings. A number of studies in the North Sea, where similar issues are of concern, and in the United States indicate that commercial fishing area preemption and gear losses are small in total (e.g., Woods Hole Oceanographic Inst., 1976; Univ. of Rhode Island, 1977; Univ. of Aberdeen, 1978; Centaur Associates, Inc., 1984). Nonetheless, these conflicts can be contentious to the parties concerned, and an estimate of these potential costs is included.

A 1982 estimate suggests that projected oil and natural gas production on Georges Bank could result in a peak annual loss in landings of $114.8 thousand in 1987 dollars (U.S. Dept. of Interior, 1982, p. 281). This implies a loss of $0.5 million per BBOE, based on the areas projected production (U.S. Dept. of Interior, 1982, p.24). This annual unit cost is used for all planning areas, except the Chukchi Sea and the Beaufort Sea. These two OCS planning areas are excluded because commercial fishing operations in these areas are minimal. The annual unit cost used for area preemption losses results in a high-cost estimate because Georges Bank is among the most productive fishing grounds, the peak-year loss estimate from the study cited is used, and the gross landed value of fish (and not net earnings) is used to evaluate losses.

Gear Losses. The owners, captains and crews of fishing vessels also will suffer losses if bottom gear is damaged by OCS oil and gas-related bottom obstructions, structures or facilities or if long lines or lobster pots are damaged or destroyed by OCS vessels. To provide perspective on this issue, in fiscal year 1985, the most recent year for which data are available, there were 199 claims by commercial fishermen against the

Table II.B.2.3 Summary of Louisiana Coastal Wetland Value Estimates (1983 dollars) Presented by Costanza and Farber

| Category | Per Acre Present Value at Specified Discount Rate: 8% | 3% |
|---|---|---|
| Commercial Fishery | $ 317 | $ 846 |
| Trapping | $ 151 | $ 401 |
| Recreation | $ 46 | $ 181 |
| Storm Protection | $1,915 | $7,549 |
| Total | $2,429 | $8,977 |

Source: Costanza and Farber (1985, p. 31)



Fishermen's Contingency Fund of the OCSLA (Title IV) for gear losses. Over 90 percent of these claims were from the Gulf of Mexico OCS, with the remainder from federal waters off California. The total of all claims was $1.6 million (U.S. Dept. of Commerce, National Marine Fisheries Service (NMFS), 1986; Jackson, personal communication, 1986). About 80 percent of the number of all claims made during the year (totaling $0.8 million) were approved; the rest were denied (U.S. Dept. of Commerce, NMFS, 1986; Jackson, personal communication, August 12, 1986). Hence, the average disbursement per approved claim for the year was $4,985.

In developing the unit cost estimate for gear losses to be used in the calculations of social cost which follow, it is assumed that all claims for gear losses in 1985--even those denied--were actually a result of OCS oil and gas activity. Further, it is assumed that 50 percent of the dollar amount of all claims will be compensated by the fund (the experience in fiscal year 1985). Using these assumptions for gear losses, and using fiscal year 1985 U.S. OCS oil and natural gas production of 1.2 BBOE (U.S. Dept. of the Interior, March, 1986, p. 15) as the base, the estimated potential social costs because of gear losses per BBOE amount to $1.4 million in 1987 dollars. This conservative (i.e., high) unit cost estimate and the 50 percent compenpensation rate are used in section III.B to estimate fishing gear losses and compensation for all OCS planning areas included in the proposed five-year schedule except the Chukchi Sea and the Beaufort Sea. These two areas are not included for this category of costs because they have insignificant commercial fishing operations and hence the potential for gear conflicts in these areas is negligible.

4. Infrastructure Costs

These costs refer to the incremental public investments made to support OCS oil and gas exploration, development, production and transportation. Publicly-funded port development and airport and road construction and improvement costs are examples of infrastructure costs which could occur as a result of additional OCS oil and gas operations. The capital costs of providing additional public services (schools, sewerage and water, public safety and so forth) because of OCS hydrocarbon activities also should be included in infrastructure costs; however, operating costs for these services normally would not be considered a social cost because these essential services would be provided to the individuals concerned regardless of their geographic location or industry of employment. In addition to the foregoing, necessary public sector infrastructure planning costs also should be included. However, such costs as transportation and onshore facility planning and investment costs, including user costs, incurred by companies are not considered infrastructure costs. This is so since they are already included in the estimation of company development costs used to estimate development benefits or net economic value.

Several interrelated factors make the development of area-specific quantitative estimates of infrastructure costs a difficult undertaking. First, the additional demands for public infrastructure services within a given OCS area depend upon the amount of oil and gas resources and their location, both of which are highly uncertain until considerable drilling takes place. Second, given the estimated incremental demands for services, the needed infrastructure investment depends upon the capacity of infrastructure facilities and their projected rate of utilization. For example, if the period of additional demands for educational services in an area because of an influx of OCS-related dependents coincided with a decline in enrollments because of a smaller school-age population of area residents, existing school buildings may be adequate to accommodate the addional demand. On the other hand, even major sewerage or water systems could be strained if OCS development occurred when these systems were operating at or near capacity.

A third factor must be recognized when attempting to assess infrastructure costs which could arise from additional OCS oil and gas operations in remote OCS areas such as the Arctic. In these OCS areas some traditional public services will not be needed (for example, educational services) because dependents will not accompany oil field personnel. Further, most, if not all, other standard public services such as water, sewerage and public safety will be provided by companies in self-contained facilities. Hence, in the Artic OCS areas, publicly supported infrastructure costs are expected to be negligible.

A number of reports provide perspectives on infrastructure costs which could result from OCS oil and gas development. For instance, using particular OCS regions as examples, the Council on Environmental Quality (CEQ) (1974) provided estimates of onshore population growth and selected public service demands as a consequence of assumed levels of OCS oil and gas resource exploitation. However, the resource assumptions used in the CEQ report have proven to be far in excess of actual resource discoveries, particularly for frontier OCS areas. Moreover, the discussion of infrastructure costs in the CEQ report is too general to be of use in the present analysis. Reports which have attempted to draw lessons from hydrocarbon development in the North Sea (e.g., Baldwin and Baldwin, 1975) provide a review of offshore and onshore experiences in this area. However, such reports are of limited value for developing detailed infrastructure assessments for the U.S. because of the many differences between the U.S. and the United Kingdom in terms of oil and gas resources, the prior history of OCS development, platform fabrication and support industries in the Gulf of Mexico and because of existing infrastructure in most U.S. OCS areas.

Although systematic data concerning possible infrastructure costs are unavailable because of the indicated difficulties inherent in estimating these costs, such costs can be expected to occur in OCS areas, particularly remote areas of Alaska and in Central and Northern California where present facilities are limited and resource estimates are more than negligible. Rather than include no estimate, which implies a zero cost, available information is used to provide what should be regarded only as a first approximation of infrastructure costs. Further consideration of infrastructure-related cost issues will be contained in the EIS for the proposed leasing program and in sale-specific EIS's.

The Bering Sea Summary Report published by the MMS OCS Oil and Gas Information Program suggests that planning and construction costs for St. George Basin infrastructure investments could amount to some $78 million (3 million dollars for planning, 9 million dollars for port construction and 66 million dollars for airport improvements) (MMS, 1984, pp. 42-44). The estimated risked developable resources in the same document are 987 million barrels of oil equivalent (p. 10). The September 1983 Summary Report indicates projected costs of about 19 million dollars for



Norton Sound (7 million dollars for planning and 12 million dollars for port construction) (1983, p. 44), with risked developable resources reported to be .414 billion barrels of oil equivalent (p. 17). The indicated resource estimates, rather than the more recent Five-Year Program resource estimate, are used because the planning and construction cost estimates were based on the prior available resource estimates.

The available information implies planning, port and airport investment costs per billion barrels of oil of 81 million dollars for St. George Basin, and 48 million dollars per BBOE for Norton Sound (in 1987 dollars). Of these costs, only the planning costs are considered additional infrastructure costs to be included in the social cost estimate developed in this appendix. The estimated potential outlays for port and airport construction and improvement can be considerable in some areas, but these items are not included as additional social costs in this appendix because oil companies are expected to pay for the cost of port and airport services in the form of user fees. As such, these costs are already included in the ordinary costs of exploration, development, production and transportation used to determine net economic value (NEV) in Appendix F. High user fees for port and airport services help explain, in part, the low NEV per BOE in remote OCS areas requiring extensive investment in these services as compared to areas where only minor infrastructure investment may be required. For example, using the base-case, initial price assumption of $29 per barrel, the estimated NEV per BOE in the St. George Basin is only $2.90, while the comparable estimate is $6.00 for No. California. In contrast, the NEV per BOE for So. California is $7.20 (Appendix F, Table 8-1) Thus, high user fees stemming from high onshore investment costs help explain why the NEV is lower for remote areas with a relative lack of infrastructure-type facilities than for areas where such facilities are available.

In summary, user fees are included in the costs of OCS operations. For this reason, they are not counted as social costs again in this appendix because to do so would be to count these costs twice.

Planning costs per BBOE range from about $24.0 million per BBOE for Norton Sound to $3.4 million for St. George Basin. As a first approximation for this social cost, the average of these two estimates is assumed to apply to all non-Artic Alaskan OCS areas outside of the two areas concerned. That is, apart from St. George Basin and Norton Sound, planning costs for all non-Arctic Alaskan OCS areas are assumed to be 13.8 million dollars per BBOE. Per unit costs for Central and Northern California are assumed to be 6.9 million dollars per BBOE--one-half of the indicated costs for the Alaskan OCS areas. Because substantial development has taken place, mature OCS areas such as the Central Gulf of Mexico and Southern California are assumed to have negligible planning costs; all other OCS areas are assigned costs equal to one-fourth those assigned to Alaska (i.e., $3.4 million per BBOE). For each OCS area, all costs are assumed to be incurred in equal annual increments in the period between the lease sale and the initiation of production.

The planning costs described above are social costs; should other publicly funded infrastructure costs for schools, water supply and sewerage, public safety and the like be incurred in an OCS area, additional social costs would be realized. An interesting issue concerns the extent to which these costs are borne by residents of the area. If planning and other costs are financed by the residents of an OCS area, then these costs also are regional costs. On the other hand, if user fees and tax revenues stemming from OCS-related operations are sufficient to cover planning and other costs, then the costs concerned do not impose a net regional cost.

Bish (1976), in his study of the fiscal effects of offshore oil and gas development on state and local government, concluded that most states could expect to receive a large favorable fiscal impact from offshore hydrocarbon development, although deficits could be realized during the first few years of exploration (p. 27). Bish's results, however, assume that OCS operations do not impose large extra expenditures. Hence, in cases such as Alaska or Northern California where large infrastructure investments may be required, it is not clear that Bish's conclusion applies. On the other hand, Texas and Louisiana studies found that OCS oil and gas operations create net fiscal deficits. However, Bish (1976, pp. 31-32) points out that because of the assumptions used, both the Texas and Louisiana studies tend to present an unduly negative assessment of fiscal impacts.

Rather than assume either a positive net fiscal impact (implying a regional gain) or a negative net fiscal impact (a regional cost) this study assumes that OCS development is on balance neutral with respect to its fiscal impact on each OCS area. The fact that State and local governments are able to establish user fees for many services (e.g., port and airport use) and can levy property, income, sales and other taxes on OCS-related operations and their personnel lends further support to the reasonableness of the position that infrastructure costs can reasonably be regarded as neutral with respect to net fisal effects at the regional level. The only exception to the assumption that infrastructure costs are fiscally neutral at the OCS planning area level concerns planning costs. All planning costs are assumed to be borne by the residents of affected OCS areas. This is a conservative, i.e., high-cost, assumption for this particular cost since some planning costs in fact are financed by oil companies. For example, pre-development environmental studies costs at the county level are paid by oil companies.

C. Summary of Unit Cost Estimates

For convenience, the unit cost estimates derived in the preceding sections are summarized below in Table II.C.1. These results, all stated in 1987 dollars, provide the central economic building blocks for the estimation of the costs of leasing OCS planning areas.



Table II.C.1 Summary of Unit Cost Estimates Used in Analysis of Costs of Proposed Final OCS Five-Year Leasing Program

| Cost Category | Cost per indicated unit ($1987)a/ |
|---|---|
| **Oil Spill Costs** | |
| 1. Cleanup and control costs | |
| a. Production platform | |
| (i) Oil comes ashore | $225-326 per bbl ashore |
| (ii) Oil remains at sea | $102-149 per bbl spilled |
| b. Pipeline | |
| (i) Oil comes ashore | $222-321 per bbl ashore |
| (ii) Oil remains at sea | $ 62- 91 per bbl spilled |
| c. Tanker | |
| (i) Oil comes ashore | $228-331 per bbl ashore |
| (ii) Oil remains at sea | $ 21- 32 per bbl spilled |
| 2. Commercial fishing | |
| (i) Direct losses | neg-$150 per bbl spilled |
| (ii) Secondary (multiplier) effects | $89-273 per $100 loss in commercial fishing income |
| 3. Tourism industry and recreation losses | |
| (i) Recreation losses | $169-675 per bbl spilled reaching shore |
| (ii) Tourism industry losses | $0.9 per dollar of recreation losses |
| 4. Ecological costs | $41.7-319 per bbl spilledb/ |
| 5. Subsistence losses | $134 per bbl spilled for coastal Alaskan OCS |
| 6. Value of lost oil | $29.00 per bbl spilledc/ |
| 7. Other costs | |
| a. Legal-administrative costs | $18 per bbl spilled |
| b. Research costs | $8 per bbl spilled for spills ≥ 1,000 bbls |
| c. Property value losses | $45.5 per bbl spilled reaching shore for "lower 48" |
| | $5 per bbl spilled reaching shore for Alaska |

Non-Spill Costs

| | |
|---|---|
| 1. Commercial fishing | |
| a. Area preemption | $0.5 million per BBOE produced |
| b. Gear losses | $1.4 million per BBOE produced |
| 2. Air pollution | $0.0195 per BOE--So. Calif. |
| | $0.0059 per BOE--Cent. Gulf |
| | $0.0029 per BOE--all other OCS areas |
| 3. Wetlands | $11,611-58,280 per acre lostb/ |
| 4. Infrastructure costs | neg.-$24.0 million per BBOEb/ |

a/See text for a discussion of the derivation of the individual unit cost estimates.

b/The indicated range reflects the range of unit cost estimates used for different OCS planning areas.

c/This is the high starting oil price which is assumed to increase by 1 percent in real terms annually.



III. Estimation of Potential Social and Regional Costs By Planning Area

A. Basic Considerations and Assumptions

1. Oil and Gas Production and Estimated Oil Spillage by Source and Area

The estimated total amount of oil spillage in an area from OCS operations depends upon the amount of oil expected to be produced, the mode of transportation (pipeline or tanker) used, and the estimated spill rate and size by source. If a spill does occur, the chance that it will reach shore depends on (1) the location of resources and the transport system relevant to the area, which determine where a spill may occur, and (2) the prevailing currents and winds, which determine the movement of oil on the water's surface.

Tables III.A.1.1 and III.A.1.2 and Attachment D summarize the basic information concerning resource and spill data for large spills used in the subsequent analysis of potential costs. The information presented is based on (1) the Interior Department's estimates of the risked value of leasable, resources unleased in each OCS planning area as of mid-1987, (2) use of the latest spill rates, by source, for large spills and small spills (Tables III.A.1.3 and III.A.1.4), and (3) the Interior Department's summary results, for each area, of the chance that a large spill which occurs will strike land within thirty days.15/

Because the use of oil spill information assumes a central role in the analysis of potential social costs, it is important to describe in some detail the oil spill information base and how it is used in the analysis. The estimated total amount of oil discharged in large spills (≥ 1,000 barrels) depends on both the estimated rate (number) of such spills per volume of oil produced or transported and on the estimated size of the large spills which may occur.

Spill rates typically are expressed as the estimated average number of spills per billion barrels of oil produced or handled. The spill rate for platforms, pipelines and tankers used in this analysis is adopted from the results of Lanfear and Amstutz (1983, pp. 356-358). Their review of oil spill statistics shows that on the United States OCS, only 12 platform spills have occured from 1964 through 1980, and only 8 pipeline spills were experienced from 1967 through 1978.

The Lanfear and Amstutz results indicate that 1 platform and 1.6 pipeline spills equal to or greater than 1,000 barrels are estimated to occur per billion barrels of oil (Table III.A.1.3). For perspective, recent OCS oil production in Gulf of Mexico has been about 373 million barrels per year. Hence, using the Lanfear and Amstutz results, we would expect, on average, 1 platform spill and something less than 1.6 pipeline spills (some oil in this region is carried by vessels) of 1,000 barrels or larger about every three years in this OCS region. This judgment assumes, of course, that historic spill rates are an adequate guide to the future.

The tanker spill rate estimated by Lanfear and Amstutz is based on their analysis of worldwide tanker accidents over the period 1974-1980. The spill rate from worldwide tanker accidents is used in the analysis in

Table III.A.1.1 Summary of Unleased Resources as of mid-1987, Transportation Mode and Probability of Spills Reaching Land for Each Planning Area for $29 Oil Starting Price

| Planning Area | Expected Leasable Resources: Oil (BBOE) | Gas (BBOE) | Total (BBOE) | Transportation Mode | Probability of Spill Reaching Land |
|---|---|---|---|---|---|
| Central Gulf of Mexico | 1.67 | 2.44 | 4.11 | P/T | .772 |
| Western Gulf of Mexico | 1.32 | 3.31 | 4.63 | P/T | .728 |
| Southern California | 0.65 | 0.17 | 0.82 | P/T | .500 |
| Central California | 0.17 | 0.06 | 0.23 | P/T | .444 |
| Navarin Basin | 0.65 | 0.14 | 0.79 | P/T/T | .150 |
| Beaufort Sea | 0.31 | 0.00 | 0.31 | P/T | .231 |
| Chukchi Sea | 0.40 | 0.00 | 0.40 | P/T | .225 |
| Northern California | 0.23 | 0.18 | 0.41 | P/T | .444 |
| East Gulf of Mexico | 0.24 | 0.23 | 0.47 | P/T | .432 |
| South Atlantic | 0.15 | 0.62 | 0.77 | P/T | .039 |
| St. George Basin | 0.11 | 0.15 | 0.26 | P/T/T | .144 |
| Mid-Atlantic | 0.06 | 0.17 | 0.23 | P | .106 |
| North Atlantic | 0.02 | 0.05 | 0.07 | P/T | .100 |
| North Aleutian | 0.01 | 0.01 | 0.02 | P/T | .342 |
| Washington-Oregon | 0.02 | 0.04 | 0.06 | T | .650a/ |
| Gulf of Alaska | 0.01 | 0.02 | 0.03 | P/T | .851 |
| Norton Basin | 0.01 | 0.01 | 0.02 | P/T | .250 |
| Kodiak | 0.00 | 0.00 | 0.00 | P/T | .545 |
| Straits of Florida | 0.01 | 0.01 | 0.01 | P | NA |
| Hope Basin | 0.00 | 0.00 | 0.00 | P | NA |
| Shumagin | 0.00 | 0.00 | 0.00 | P | NA |
| Cook Inlet | 0.00 | 0.00 | 0.00 | P/T | |
| Rest of Alaska | --------neg.-------- | | | NA | NA |

a/Because no estimate has yet been made of the chance that an oil spill in the Washington-Oregon area would strike land, we have used the average of the indicated probabilities for the nearest two OCS areas, No. California and the Gulf of Alaska, as the estimate for the Washington-Oregon OCS planning area.



Table III.A.1.2 Summary of Unleased Resources as of mid-1987, Transportation Mode and Probability of Spills Reaching Land for Each Planning Area for $14 Oil Starting Price

| Planning Area | Expected Leasable Resources: Oil (BBOE) | Gas (BBOE) | Total (BBOE) | Transportation Mode | Probability of Spill Reaching Land |
|---|---|---|---|---|---|
| Central Gulf of Mexico | 1.60 | 2.33 | 3.93 | P/T | .772 |
| Western Gulf of Mexico | 1.08 | 2.71 | 3.79 | P/T | .728 |
| Southern California | 0.28 | 0.10 | 0.38 | P/T | .500 |
| Central California | 0.09 | 0.03 | 0.12 | P/T | .444 |
| Navarin Basin | 0.00 | 0.00 | 0.00 | P/T/T | .150 |
| Beaufort Sea | 0.00 | 0.00 | 0.00 | P/T | .231 |
| Chukchi Sea | 0.00 | 0.00 | 0.00 | P/T | .225 |
| Northern California | 0.10 | 0.08 | 0.18 | P/T | .444 |
| East Gulf of Mexico | 0.09 | 0.09 | 0.18 | P/T | .432 |
| South Atlantic | 0.05 | 0.20 | 0.25 | P/T | .039 |
| St. George Basin | 0.00 | 0.00 | 0.00 | P/T/T | .144 |
| Mid-Atlantic | 0.03 | 0.08 | 0.11 | P | .106 |
| North Atlantic | 0.00 | 0.01 | 0.01 | P/T | .100 |
| North Aleutian | 0.00 | 0.00 | 0.00 | P/T | .342 |
| Washington-Oregon | 0.01 | 0.04 | 0.05 | T | .650a/ |
| Gulf of Alaska | 0.00 | 0.00 | 0.00 | P/T | .851 |
| Norton Basin | 0.00 | 0.00 | 0.00 | P/T | .250 |
| Kodiak | 0.00 | 0.00 | 0.00 | P/T | .545 |
| Straits of Florida | 0.00 | 0.00 | 0.00 | P | NA |
| Hope Basin | 0.00 | 0.00 | 0.00 | P | NA |
| Shumagin | 0.00 | 0.00 | 0.00 | P | NA |
| Cook Inlet | 0.00 | 0.00 | 0.00 | P/T | |
| Rest of Alaska | --------neg.-------- | | | NA | NA |

a/Because no estimate has yet been made of the chance that an oil spill in the Washington-Oregon area would strike land, we have used the average of the indicated probabilities for the nearest two OCS areas, No. California and the Gulf of Alaska, as the estimate for the Washington-Oregon OCS planning area.

this appendix because a comparable rate has not been estimated for vessels operating in U.S. waters.

Regarding the estimated size of individual large spills, a central problem concerns how to represent the size of the "typical" spill from platforms, pipelines and tankers. Spill statistics are dominated by a few large spills; most spills are relatively small. The following facts illustrate the importance of this point:

* A single tanker spill--the 1978 supertanker AMOCO CADIZ spill (1.6 million barrels)--constitutes about 6 percent of all oil lost in the 469 large spills included in the MMS vessel oil spill data base over the entire period 1957-1985. The five largest spills comprise almost one quarter (24 percent) of all of the oil reported lost in vessel spills over the 18 year period.

* The 77,000 barrels reported by Lanfear and Amstutz as spilled in the 1969 Santa Barbara accident account for 35 percent of all oil spilled in the 12 large domestic platform spills since 1964.

* The 1967 West Delta 73 pipeline spill (160,638 barrels) represents fully 77 percent of all oil spilled in the 8 large United States pipeline spills since 1967.

This appendix uses the arithmetic mean to represent the "typical" spill size for large spills (1,000 barrels or greater) for each source (Table III.A.1.3). For platforms and piplines, the mean spill size was calculated from the data presented in Lanfear and Amstutz (1983, Tables 1 and 2, p. 356). For tankers, two average spill sizes must be considered, one for U.S. vessels and one for foreign vessels. First, since only U.S. flag vessels can transport oil produced on the OCS, the relevant historic spills to be considered were those in U. S. waters by domestic vessels. The arithmetic mean of the 43 large U.S. spills by domestic vessels for the period 1957-1985 contained in the MMS vessel oil spill data file is 14,707 barrels (Anderson, personal communication, July, 1986). Hence, 14,707 barrels is the spill size used hereafter to characterize the average size of spills by vessels carrying OCS oil.

Second, imported oil delivered to U.S. ports typically will be carried by foreign vessels which generally are less expensive to operate than U.S. flag vessels. Hence, the average spill size for tankers delivering imported oil should be based on the record for foreign tankers. Moreover, the spill size for foreign tankers used in the analysis should include only spills by foreign tankers in U.S. waters. This is because worldwide vessel spill statistics are dominated by a relatively small number of supertanker spills, as noted above; and supertankers are used very little in U.S. waters. Also, historic statistics on spills by foreign vessels in U.S. waters are more reflective of domestic operating conditions and regulations than are the worldwide statistics.

The average size for the 94 foreign vessels spills in U.S. waters reported in the MMS vessel spill data file for 1957-1985 is 20,769 barrels. This figure is used in this appendix as the average size of spills from vessels carrying imported oil. It is noted that this figure is considerably smaller than the average spill size by foreign vessels worldwide (59,138) for the same period. It also is noted that use of the



Table III.A.1.3 Expected Number and Size of Spills ≥ 1000 Barrels Per Billion Barrels of Oil Produced or Transported

| Source | Expected spill rates/ | Average Size (bbls) |
|---|---|---|
| Platform | 1.0 | 18,378a/ |
| Pipeline | 1.6 | 25,937a/ |
| Tanker | 1.3 (at sea .9)<br>(in port .4) | 14,707 (domestic)b/<br>20,769 (foreign)b/ |

Source: a/Lanfear and Amstutz (1983).
b/MMS vessel oil spill file for large spills.

20,769 rather than the 59,138 average spill size for foreign tankers transporting imported oil will lead to higher estimates of net social cost. This is because a given quantity of oil backed out by OCS production will yield a lower estimate of foreign tanker oil spillage avoided when the lower average spill size is used.

Given the small number of platform and pipline spills and the fact that the spill statistics are dominated by a relatively few very large oil spills, one could argue that use of some measure of central tendency other than the mean may be justified. Use of the median value results in a spill size of 7,522 bbls for platforms, 5,500 bbls for pipelines, and about 17,800 bbls for tankers. Use of the mode or most likely value results in still smaller estimates of the "typical" spill equal to or greater than 1,000 bbls. Hence, use of the mean size for large spills is consistent with the adopted principle of using a conservative, high-cost approach when a choice must be made among possible values for a variable.

In addition to large spills, 395 small spills ((1,000 bbls) are expected to occur per billion barrels of OCS oil production (Table III.A.1.4). Small spills from production platforms and pipelines in each area are assumed to have the same probability of reaching shore as the large platform spills indicated in Table III.A.1.1. While the number of small spills is large, the total amount estimated to be spilled is equivalent to only 3,762 barrels per billion barrels of production. This is in contrast with the amount estimated to be lost in large spills per billion barrels of oil from platforms (18,378 bbls), pipelines (41,500 bbls) and tankers (19,119 bbls).

The data in Table III.A.1.4 pertain to spills from production platforms and pipelines only; rates for small spills from OCS-related tankers are not available. However, the omission of small spills from tankers has a negligible effect on the overall results because the increase in the number of small spills expected from OCS tankers will tend to be offset by the decrease in small spills from imported oil that is displaced by OCS oil production.

Given the spill rates for large and small spills, given planning area-specific estimates of unleased oil resources and given the number and expected size of spills and the number expected to come ashore, it is now possible to estimate total oil spillage for each area. This information, summarized in Tables III.A.1.5 and III.A.1.6, indicates for each planning area the total expected spillage coming ashore and remaining at sea from the production and transportation of all the OCS oil resources unleased as of mid-1987 at the starting oil prices of $14 and $29 a barrel. The estimated amount spilled for each area indicated in the tables also includes oil spilled from tankers transshipping oil from <u>other</u> OCS areas.

2. Assumption Concerning Backout of Imported Oil Resulting from OCS Natural Gas Production

The production of OCS natural gas to some extent will reduce imports of oil by substituting, for example, for fuel oil used for space heating and utilities. In the analysis which follows it is assumed that on a Btu basis over the entire production time horizon, each unit of natural gas replaces a half-unit of imported oil. Inasmuch as a one-for-one substitution of natural gas for imported oil is possible (Personal



Table III.A.1.4 Estimated Number and Size of Spills (1,000 Barrels Per Billion Barrels of Oil Produced

| Spill Rate | Spill Size | Average Size (bbls) |
|---|---|---|
| 381 | 1-49 | 4.2 |
| 14 | 50-999 | 154.4 |

Source: U.S. Department of the Interior (January, 1983, p.270); Ms. Susan Gaudry, Minerals Management Service, Gulf of Mexico Regional Office, personal communication, October 12, 1984.

Table III.A.1.5 Estimated Total Amount Spilled and Amount Reaching Shore as a Result of Producing Unleased Resources*) From <u>ALL</u> Areas (Barrels): $29 per Barrel Starting Price

| AREA | REACHING SHORE | REMAINING AT SEA | TOTAL EXPECTED SPILLAGE |
|---|---|---|---|
| CGOM | 76852 | 22116 | 98968 |
| WESTGOM | 56307 | 20312 | 76619 |
| NAVARIN | 11850 | 34893 | 46743 |
| S.CALIF | 22113 | 18753 | 40865 |
| CHUKCHI | 6904 | 19728 | 26632 |
| BEAUFRT | 5469 | 15171 | 20640 |
| EASTGOM | 9504 | 10615 | 20119 |
| S.ATLAN | 1319 | 10971 | 12290 |
| N.CALIF | 5767 | 6383 | 12151 |
| CEN.CALIF | 4582 | 4915 | 9496 |
| ST.GEORGE | 986 | 3999 | 4985 |
| MID-ATLAN | 782 | 3832 | 4614 |
| NORTON | 218 | 552 | 770 |
| ORE/WASH | 519 | 221 | 740 |
| N.ATLAN | 151 | 509 | 660 |
| N.ALEUTIAN | 220 | 372 | 592 |
| GULFALASKA | 474 | 79 | 553 |
| STR OF FLORIDA | 29 | 384 | 414 |
| KODIAK | 0 | 0 | 0 |
| HOPE | 0 | 0 | 0 |
| SHUMAGIN | 0 | 0 | 0 |
| COOK INLET | 0 | 0 | 0 |

*) All Resources Unleased as of mid 1987



Table III.A.1.6 Estimated Total Amount Spilled and Amount Reaching Shore as a Result of Producing Unleased Resources*) From <u>ALL</u> Areas (Barrels): $14 per Barrel Starting Price

| AREA | REACHING SHORE | REMAINING AT SEA | TOTAL EXPECTED SPILLAGE |
|---|---|---|---|
| CGOM | 73486 | 21147 | 94633 |
| WESTGOM | 46091 | 16627 | 62718 |
| S.CALIF | 8113 | 7553 | 15666 |
| EASTGOM | 3640 | 4065 | 7705 |
| N.CALIF | 2492 | 2753 | 5245 |
| CEN.CALIF | 2273 | 2510 | 4783 |
| S.ATLAN | 460 | 3823 | 4283 |
| MID-ATLAN | 374 | 1833 | 2207 |
| ORE/WASH | 385 | 165 | 550 |
| N.ATLAN | 22 | 73 | 94 |
| NAVARIN | 0 | 0 | 0 |
| BEAUFRT | 0 | 0 | 0 |
| CHUKCHI | 0 | 0 | 0 |
| ST.GEORGE | 0 | 0 | 0 |
| N.ALEUTIAN | 0 | 0 | 0 |
| GULFALASKA | 0 | 0 | 0 |
| NORTON | 0 | 0 | 0 |
| KODIAK | 0 | 0 | 0 |
| HOPE | 0 | 0 | 0 |
| SHUMAGIN | 0 | 0 | 0 |
| COOK INLET | 0 | 0 | 0 |
| STR OF FLORIDA | 0 | 0 | 0 |

*) All Resources Unleased as of mid 1987

communication, H. William Hochheiser, August 6, 1986) the one-half substitution rule used here is a conservative, i.e., high-cost, assumption.

3. Basic Assumptions Regarding Imports and Oil Transportation

Two remaining issues must be addressed before the estimates of costs can be developed. First, the OCS oil and natural gas-caused reductions in imports of crude oil must be made area-specific in order to recognize the costs avoided because OCS oil and natural gas production reduces the amount of import-associated tanker spills. To do this, the recent port-of-entry pattern of foreign crude oil is assumed to apply over the period of concern in this analysis (Table III.A.3.1). OCS oil and natural gas production in any area is assumed to lead to reductions in imported crude oil, by area, based on the proportions indicated in Table III.A.3.1.

The worldwide tanker spill rate presented in Table III.A.1.3 is assumed to apply to foreign as well as domestic tankers. All foreign tankers are assumed to have the same expected large spill size, 20,769 bbls. For foreign tankers the following geographic pattern of oil spills is assumed: 15 percent at the foreign port of origin, 15 percent in the U.S. OCS area destination (all of which is assumed to strike land), and 70 percent in transit. Of this last amount, one third is assumed to occur in domestic waters in the destination OCS area and has the same chance of reaching shore as OCS-related spills in that area.

Finally, it is necessary to account for the geographic distribution of oil spills from tankers used to transship OCS oil among planning areas. This is particularly important for Alaskan OCS oil which will be shipped considerable distances to refineries on the West Coast (and conceivably Texas and the East Coast), thereby exposing sections of other planning areas to tanker oil spills. Alaskan oil is assumed to be transported following the pattern developed for the environmental analysis supporting the Draft Proposed 5-Year Oil and Gas Leasing Program. At-sea spills are distributed among planning areas in proportion to the linear distance traveled within the planning area according to the supporting environmental analysis. All oil shipped from Alaskan areas is assumed to be transported to refineries on the West Coast.16/

B. Results

1. Introduction: An Example

Before the detailed results of cost by area are presented, it is helpful to summarize by means of an example the approach used to estimate potential social and regional costs. For this exercise, the area employed is the Western Gulf of Mexico. At a starting price of $29 a barrel this area has leasable resources as of Mid-1987 of 1.32 billion barrels of oil and 18.6 trillion cubic feet of natural gas, for a total of 4.63 BBOE. Seventy-five percent of the oil production is expected to be delivered to refineries by pipeline; the remaining twenty-five percent is transported by tanker. The overall probability of a spill ≥1,000 bbls reaching shore in this area is .728. The analysis begins with an estimation of expected spillage, proceeds through the estimation of total potential oil spill and non-oil spill costs and concludes with an estimate of the present



value of the costs resulting from the proposed leasing and development of all of the unleased resources in the example area at time zero (mid-1987).

1. Determine the total estimated amount lost in large spills, by source, as if all oil was leased in mid-1987. The estimated number of large spills for each source is the product of the volume of oil produced or transported in billions of barrels times the spill rate per billion barrels (Tables III.A.1.1 and III.A.1.3). Over the life of production in this area, the estimated number of large spills is:

Platform: 1.32 billion x 1.0 = 1.32 spills
Pipeline: .99 billion x 1.6 = 1.58 spills
Tanker: .33 billion x 1.3 = .43 spills

The estimated amount spilled in large spills over the entire production period is equal to the expected number times the expected size for each source:

Platform: 1.32 x 18,378 = 24,259 bbls spilled
Pipeline: 1.58 x 25,937 = 40,980 bbls spilled
Tanker: .43 x 14,707 = 6,324 bbls spilled

The estimated amount of oil from large spills to reach shore over the life of oil production is calculated in two steps. First, the amount estimated to reach shore from platforms and pipelines is the product of the estimated amount spilled times the chance that a spill will reach shore (.728 in this case):

Platform: .728 x 24,259 = 17,661 bbls ashore
Pipeline: .728 x 40,980 = 29,833 bbls ashore

Second, we must add the amount of oil lost in large tanker spills, that is estimated to come ashore. This estimate is 4,857 barrels (= 1.1 x .33 x 14,707 x .728 plus .2 x .33 x 14,707). Thus, the total amount of oil from large spills estimated to come ashore is 52,351 barrels (= 17,661 + 29,833 + 4,857).

Finally, a similar approach is used for small spills. The estimated amount of spillage per billion barrels is equal to the expected number of spills per billion barrels times the expected size of each spill (Table III.A.1.4) which equals 3,762 barrels. For the Western Gulf of Mexico, the total amount of oil lost in small spills is:

1.32 x 3,762 = 4,966 bbls

Because no oil spill trajectory modeling has been done for small spills, the chance of small spills coming ashore is assumed to be the same as the chance that large spills will strike land, .728 in this case. Thus, of the total amount of oil lost in small spills, 3,615 bbls are expected to come ashore (= 4,966 x .728) over the entire production period.

The total amount of oil estimated to be lost from spills resulting from the production and transportation of all Western Gulf of Mexico oil resources unleased as of mid-1987 over the life of all production operations amounts to 76,529 barrels as summarized below. The estimated annual oil spillage is calculated by multiplying the estimated yearly oil production for the area by the expected number and size of spills (Tables III.A.1.3 and III.A.1.4). The approach used to estimate annual production for each OCS area is described in Attachment A.

Estimated amount spilled (21,000 bbls)
Over the entire production period

| | Coming ashore | Remaining at sea |
|---|---|---|
| Production | 17,661 | 6,598 |
| Pipeline | 29,833 | 11,147 |
| Tankers | 4,857 | 1,467 |
| Total large spills | 52,351 | 19,212 |
| Plus: Small spills a/ | 3,615 | 1,351 |
| Total large & small spills | 55,966 b/ | 20,563 b/ |

a/ Distributed between "coming ashore" and "remaining at sea" in the same proportion as estimated for large platform spills for this area.

b/ These totals do not agree with data in Table III.A.1.5. due to rounding errors in Table III.A.1.5., which result from the annualization of production and spillage. See Attachment A for the approach used to annualize production.

2. Determine the present value of oil-spill costs for oil coming ashore and oil remaining at sea as if all of the area's unleased resources were leased in mid-1987. This calculation uses the per barrel oil spill costs described in detail in Section II, together with the estimated annual spillage outlined in the previous step, to estimate the cost for each source of the spilled oil coming ashore and remaining at sea. Detailed results of the discounted cost by category, for each source, are presented in Attachment B.

Assuming all unleased recoverable resources are leased in mid-1987, the present value of total oil spill costs as of this date is $19.2 million.

| | |
|---|---|
| Platforms: | $ 7.3 |
| Pipelines: | 10.2 |
| Tankers: | 1.7 |
| Present value of oil spill costs | $19.2 |

3. Determine the present value of air quality losses. This cost is established by multiplying the estimated air pollution cost per unit of oil and gas production for the Western Gulf of Mexico area (see section II.B.1) times the estimated annual production for the area obtained using the procedure described in Attachment A. The present value of these costs, $3.5 million, is determined by discounting the annual estimated cost over the life of production for this area for the leasable hydrocarbon resources unleased as of mid-1987.



4. Determine the present value of wetland losses. This loss of $2.6 million is estimated using the approach developed in Section II.B.2 and the annual production profile generated using the procedure described in Attachment A. For this calculation, the estimated value of an acre of wetland lost is $14,270 in the Western Gulf of Mexico.

5. Determine the present value of estimated commercial fishing area preemption and gear conflicts losses. The present value of this loss is estimated to be $2.6 million. It is determined by multiplying the applicable loss coefficients per BBOE (see Table II.C.1) times the annual BBOE production for each area estimated using the procedure described in Attachment A and then discounting the annual values to get the present value.

6. Estimate the potential infrastructure cost, which covers pre-lease sale and post-lease sale planning costs, as described in section II.B.4. The present value of these costs for this OCS area is estimated to be $13.9 million.

7. Finally, the estimated potential social costs avoided because OCS oil replaces imported oil--thereby resulting in fewer import-related oil spills--must be recognized. The 1.32 billion barrels produced in the Western Gulf of Mexico reduce imports by an equivalent amount, and the 3.31 BBOE of natural gas lower imports of oil by about 1.65 billion barrels. Reduced imports are assumed to be distributed among OCS areas based on the recent historic crude oil import shares presented in Table III.A.2.1. Knowledge of the amount of reduced oil imports by area, tanker spill rates and the expected size of spills (III.A.1.3), and the cost of oil spills per barrel in each area permits one to estimate the potential social costs avoided from reduced imports. In this case, the social cost avoided to the nation as a whole has a present value of $5.9 million.

In summary, the present value of the estimated potential social costs to the nation as a whole, assuming all Western Gulf of Mexico leasable resources are leased in mid-1987, is:

| | |
|---|---|
| Present value of estimated potential oil spill costs: | $19.2 |
| Present value of estimated potential non-spill costs: | 22.5 |
| Gross estimated potential social costs: | 41.7 |
| Less: Present value of estimated potential social costs avoided by entire nation by reducing imported oil: | -$ 5.9 |
| Total estimated potential social net cost: | $35.8 |

Now that the potential net social cost has been estimated, the potential regional cost can be established. Regional cost measures the cost borne by residents of geographic locations adjoining the Western Gulf of Mexico as a result of production in all OCS areas.

The potential regional cost is measured by reducing the gross regional oil spill and non-spill costs totaling $49.5 million by (1) the social costs avoided because of reduced imports into this area and by (2) estimated compensation payments for OCS oil spills and commercial fishing gear losses. The calculations are based on the assumptions that compensation is paid for 50 percent of all OCS-related oil spill costs (excluding non-market recreation losses and the value of the lost oil) and 50 percent of losses attributable to commercial fishing gear conflicts with OCS oil and gas operations. The relevant calculations follow with all numbers stated in present value terms.

| | |
|---|---|
| Gross area regional costs | $49.5 |
| Less: | |
| Compensation payments for: | |
| OCS-related oil spills and commercial fish. gear losses | - 9.7 |
| Social costs avoided because of reduced imports into area | -17.9 |
| Estimated potential regional cost: | $21.8 |

In summary, the present value of the <u>regional cost</u> for the Western Gulf of Mexico of producing all the oil and gas resources unleased as of mid-1987 is $21.8 million.

Following the above procedure, estimates have been made of the potential social and regional costs of the proposed final five-year leasing program to each OCS planning area. These results are presented in the next section.

2. Estimated Potential Social and Regional Costs for Each OCS Planning Area

<u>Introduction</u>. Using the data, assumptions and analytical approach described in detail in the preceding sections, estimates have been made of the present discounted value of the potential social and regional costs from producing all of the leasable recoverable hydrocarbon resources unleased as of mid-1987.

Only the aggregated potential oil spill and non-spill cost results for each planning area are presented in this section. A detailed listing of individual oil spill costs for each OCS area is presented in Attachment B, and a listing of potential non-spill costs for each area is given in Attachment C. Attachment D provides a summary of resource information and key results for each area.

In the following subsections the results of the estimation of potential social and regional costs are explained. The results of a sensitivity analysis of social costs for each area also are described.

<u>Estimated Potential Social Costs Results for Each OCS Area</u>. Tables III.B.2.1 and III.B.2.2 present a summary of the potential estimated social costs for each OCS area as a result of producing and transporting all of the estimated leasable oil and gas resources unleased as of mid-1987. Continuing our use of the Western Gulf of Mexico as an example, the results in the table should be interpreted as described below.



Using the leasable resource estimates for the $29 starting oil price, the value of the oil spill costs ($19.2 million) plus the non-oil spill costs ($22.5 million) for the Western Gulf of Mexico is $41.7 million in 1987 dollars. This figure represents the total, quantifiable social costs resulting from the production and transportation of all of the area's resources. However, the potential social cost estimate of $41.7 million does not yet include recognition of the social costs avoided because oil and natural gas from the Western Gulf of Mexico will back out imports, thereby reducing foreign tanker spills. Hence, the $41.7 social cost figure at this point represents "gross" social costs.

The potential social costs avoided when Western Gulf of Mexico oil and natural gas backs out imports is $5.9 million (Column 4). These social cost savings are distributed among the different OCS areas based on the geographical pattern of crude oil imports indicated in Table III.A.2.1. After the social costs avoided are subtracted from gross social costs, we arrive at net social costs of $35.8 million for the Western Gulf of Mexico (Column 5). In summary, the $35.8 million is the estimated cost of developing all of the Western Gulf of Mexico leasable oil and gas resources unleased as of mid-1987, to the Nation as a whole.

At the $29 per barrel starting price for oil, estimated social costs range from $42.3 million for the Central Gulf of Mexico to less than $1 million for several Alaskan OCS areas and for the No. Atlantic, Oregon-Washington and the Straits of Florida (Table III.B.2.1). For the $14 a barrel initial oil price, net social costs range from $41.8 million for the Central Gulf of Mexico to less than one million for 14 of the remaining 21 planning areas. Comparing the two oil price cases, net social cost show a negligible drop for the Central Gulf of Mexico because leasable resources for this particular area are not very sensitive to price changes over the range considered. However, resource estimates--and hence net social costs--for many other OCS areas decline considerably as the starting price of oil falls from $29 to $14 a barrel.

Generally speaking, there is a direct association between an area's total social cost and the total leasable hydrocarbon resources estimated to be contained in the area. The OCS areas with the largest estimated unleased OCS resources, such as the Western Gulf of Mexico, Central Gulf of Mexico and So. California, also have among the highest estimated potential social costs, while the areas with very low estimated unleased resources, such as several of the Alaskan OCS areas and the No. Atlantic and the Oregon and Washington areas, have low or negligible estimated total potential social costs.

Total hydrocarbon resources alone, however, do not determine total potential social costs. The oil-gas resource composition, the transportation mode, the estimated chance that spills which occur will reach shore, together with the characteristics of an area's marine and coastal resources and environmental productivity and sensitivity, also influence total potential social costs. For example, the Central Gulf of Mexico has resources which are about 10 percent less than, but potential social costs which are almost twenty percent greater then, the corresponding estimates for the Western Gulf of Mexico at a $29 oil starting price. One important reason for the difference in social costs estimates for the two areas is that the Central Gulf of Mexico is expected to contain considerably more oil than the Western Gulf, hence, estimated spillage is greater for the former area. Other reasons for the

Table III.B.2.1 Summary of the Present Discounted Value of Estimated Potential Social Costs for Each OCS Planning Area: $29 per Barrel Starting Price (Millions of 1987 dollars)

| AREA | (1) OIL SPILL COSTS | (2) NON SPILL COSTS | (3)=(1)+(2) GROSS SOCIAL COSTS | (4) LESS: COST AVOIDED FROM REDUCED IMPORTS[a] | (5)=(3)-(4) TOTAL NET DISCOUNTED SOCIAL COSTS[b] |
|---|---|---|---|---|---|
| CGOM | 34.7 | 16.0 | 50.7 | 8.4 | 42.3 |
| WESTGOM | 19.2 | 22.5 | 41.7 | 5.9 | 35.8 |
| NAVARIN | 9.4 | 9.5 | 18.9 | 3.2 | 15.7 |
| S.CALIF | 11.3 | 5.3 | 16.7 | 4.3 | 12.3 |
| N.CALIF | 3.4 | 4.4 | 7.8 | 1.5 | 6.3 |
| EASTGOM | 3.8 | 2.9 | 6.7 | 1.1 | 5.6 |
| S.ATLAN | 1.9 | 3.9 | 5.8 | 0.8 | 5.0 |
| ST.GEORGE | 1.3 | 3.6 | 4.9 | 0.5 | 4.4 |
| BEAUFRT | 4.5 | 1.4 | 5.9 | 1.4 | 4.4 |
| CEN.CALIF | 2.5 | 2.2 | 4.8 | 1.1 | 3.6 |
| CHUKCHI | 4.5 | 0.3 | 4.8 | 1.6 | 3.2 |
| MID-ATLAN | 1.0 | 1.3 | 2.3 | 0.3 | 2.0 |
| N.ATLAN | 0.1 | 0.7 | 0.8 | 0.1 | 0.7 |
| NORTON | 0.3 | 0.4 | 0.7 | 0.1 | 0.6 |
| GULFALASKA | 0.2 | 0.3 | 0.5 | 0.0 | 0.5 |
| ORE/WASH | 0.3 | 0.3 | 0.6 | 0.1 | 0.5 |
| N.ALEUTIAN | 0.2 | 0.2 | 0.4 | 0.0 | 0.4 |
| STR OF FLOR | 0.0 | 0.3 | 0.4 | 0.0 | 0.4 |
| KODIAK | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| HOPE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SHUMAGIN | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| COOK INLET | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

a) Estimated Potential Social costs avoided to the nation as a whole from reduced needs for imported oil, assuming reduced imports (and associated oil spills) are distributed across OCS planning areas in the same proportion as indicated in Table III.A.3.1.
b) Zero costs indicated in the table occur because area contains negligible leasable resources and estimated costs are less than $.1 million.



Table III.B.2.2 Summary of the Present Discounted Value of Estimated Potential Social Costs for Each OCS Planning Area: $14 per Barrel Starting Price (Millions of 1987 dollars)

| AREA | (1) OIL SPILL COSTS | (2) NON SPILL COSTS | (3)=(1)+(2) GROSS SOCIAL COSTS | (4) LESS: COST AVOIDED FROM REDUCED IMPORTS[a] | (5)=(3)-(4) TOTAL NET DISCOUNTED SOCIAL COSTS[b] |
|---|---|---|---|---|---|
| CGOM | 33.2 | 15.6 | 48.8 | 7.0 | 41.8 |
| WESTGOM | 15.7 | 18.9 | 34.6 | 4.2 | 30.4 |
| S.CALIF | 4.9 | 2.8 | 7.7 | 1.6 | 6.0 |
| N.CALIF | 1.5 | 2.7 | 4.2 | 0.6 | 3.6 |
| EASTGOM | 1.4 | 1.8 | 3.2 | 0.4 | 2.8 |
| CEN.CALIF | 1.3 | 1.4 | 2.7 | 0.5 | 2.2 |
| S.ATLAN | 0.7 | 1.7 | 2.4 | 0.2 | 2.1 |
| MID-ATLAN | 0.5 | 0.8 | 1.3 | 0.1 | 1.1 |
| N.ATLAN | 0.0 | 0.5 | 0.5 | 0.0 | 0.5 |
| ORE/WASH | 0.2 | 0.2 | 0.5 | 0.1 | 0.4 |
| NAVARIN | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| BEAUFRT | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| CHUKCHI | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| ST.GEORGE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| N.ALEUTIAN | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| GULFALASKA | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| NORTON | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| KODIAK | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| HOPE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SHUMAGIN | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| COOK INLET | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| STR OF FLOR | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

a) Estimated Potential Social costs avoided to the nation as a whole from reduced needs for imported oil, assuming reduced imports (and associated oil spills) are distributed across OCS planning areas in the same proportion as indicated in Table III.A.3.1.
b) Zero costs indicated in the table occur because area contains negligible leasable resources and estimated costs are less than $.1 million.

difference in the estimated total potential social costs between the two areas include the fact that the Central Gulf has more valuable commercial fisheries (Table II.A.2.1) and a higher environmental productivity and sensitivity ranking (Table II.A.4.1) and is potentially more susceptible to wetland alterations (Table II.B.2.2.) than the Western Gulf of Mexico.

Another important factor determining an area's total potential social cost is that area's need for infrastructure investment caused by OCS oil and gas development. Infrastructure costs in the form of planning costs could be relatively high for several remote Alaskan OCS areas, for Central and Northern California, and for the Western Gulf of Mexico.

The net effect of all of the myriad of factors influencing social costs can be examined by assessing the social costs per unit of production--here measured as the potential social costs per billion barrels of oil equivalent (BBOE). This information is presented for each OCS area in Tables III.B.2.3 and III.B.2.4.

Estimated potential social cost per BBOE range from $36.5 million for the Straits of Florida to $6.5 million for the So. Atlantic and is not directly correlated with an area's total leasable resources. The relatively high potential social cost per BBOE for the Straits of Florida is explained by a combination of possible wetland alterations and low resource estimates for this area. The use of a pipeline to transport natural gas from this area could alter some coastal wetlands. Losses caused by coastal wetland alteration is essentially a "fixed" cost because it depends primarily on the number of pipelines (one in this case) and is not very sensitive to changes in resource estimates. Because the resource estimate for this area is so low (.01 BBOE), the estimated social cost per BBOE is highly sensitive to fixed costs. Hence, for this reason, the potential social cost per BBOE for the Straits of Florida is quite high, even though estimated total potential social cost for the area is low.

The low potential social cost per BBOE for the So. Atlantic ($6.5 million) reflects the fact that the modest resources estimated for this area are primarily natural gas (Table III.A.1.1), so that the potential for oil spills is low. Also the chance of any spilled oil reaching shore in this area (0.04) is among the lowest for any OCS area.

As noted, the cost per BBOE is determined by a number of factors. One important factor is the estimated transportation mode for oil. Under the assumptions used for this analysis, pipelines result in considerably more estimated oil spillage (41,499 barrels per billion barrels of oil (BBO) than domestic tankers (19,119 per BBO). Hence, areas that rely on pipelines more than tankers to transport oil can be expected to have higher potential social costs per BBO, other things being the same.

With respect to the composition of potential social costs, an important conclusion is that oil spill costs exceed non-oil spill costs for most OCS areas. For the lower 48 OCS planning areas, the most important potential oil spill social costs are tourism and recreation losses, commercial fishing, cleanup and control costs and ecological costs. For the Alaskan OCS areas, cleanup and control costs, ecological costs and subsistence losses are the principal estimated potential oil spill costs.



Table III.B.2.3 Total and per BBOE net Estimated Potential Social Costs $29 per Barrel Starting Price (in Millions of 1987 Dollars)

| | TOTAL NET SOCIAL COSTS | NET COSTS PER BBOE[a] |
|---|---|---|
| STR OF FLORID | 0.4 | 36.5 |
| NORTON | 0.6 | 30.1 |
| NAVARIN | 15.7 | 19.9 |
| N.ALEUTIAN | 0.4 | 18.8 |
| ST.GEORGE | 4.4 | 16.8 |
| GULFALASKA | 0.5 | 16.4 |
| CEN.CALIF | 3.6 | 15.8 |
| N.CALIF | 6.3 | 15.4 |
| S.CALIF | 12.3 | 15.0 |
| BEAUFRT | 4.4 | 14.3 |
| EASTGOM | 5.6 | 11.9 |
| N.ATLAN | 0.7 | 10.6 |
| CGOM | 42.3 | 10.3 |
| MID-ATLAN | 2.0 | 8.6 |
| CHUKCHI | 3.2 | 8.0 |
| WESTGOM | 35.8 | 7.7 |
| ORE/WASH | 0.5 | 7.5 |
| S.ATLAN | 5.0 | 6.5 |
| KODIAK | 0.0 | 0.0 |
| HOPE | 0.0 | 0.0 |
| SHUMAGIN | 0.0 | 0.0 |
| COOK INLET | 0.0 | 0.0 |

[a] Zero costs indicated in the table occur because area contains negligible leasable resources and estimated costs are less than $.1 million.

Table III.B.2.4 Total and per BBOE net Estimated Potential Social Costs $14 per Barrel Starting Price (in Millions of 1987 Dollars)

| | TOTAL NET SOCIAL COSTS | NET COSTS PER BBOE*) |
|---|---|---|
| N.ATLAN | 0.5 | 48.0 |
| N.CALIF | 3.6 | 20.1 |
| CEN.CALIF | 2.2 | 18.5 |
| S.CALIF | 6.1 | 15.9 |
| EASTGOM | 2.9 | 15.8 |
| CGOM | 41.8 | 10.6 |
| MID-ATLAN | 1.1 | 10.3 |
| S.ATLAN | 2.1 | 8.5 |
| WESTGOM | 30.4 | 8.0 |
| ORE/WASH | 0.4 | 7.8 |
| NAVARIN | 0.0 | 0.0 |
| BEAUFRT | 0.0 | 0.0 |
| CHUKCHI | 0.0 | 0.0 |
| ST.GEORGE | 0.0 | 0.0 |
| N.ALEUTIAN | 0.0 | 0.0 |
| GULFALASKA | 0.0 | 0.0 |
| NORTON | 0.0 | 0.0 |
| KODIAK | 0.0 | 0.0 |
| HOPE | 0.0 | 0.0 |
| SHUMAGIN | 0.0 | 0.0 |
| COOK INLET | 0.0 | 0.0 |
| STR OF FLORID | 0.0 | 0.0 |

*) Zero costs indicated in the table occur because area contains negligible leasable resources and estimated costs are less than $.1 million.



For the non-oil spill costs, estimated potential wetland and air quality costs are the largest potential costs in this category for several OCS areas. Though small relative to total potential social costs, potential wetland losses and/or air quality losses could be a relatively substantial part of potential social cost for the Central and Western Gulf of Mexico and So. California OCS areas (see Attachment C). It is important to stress, however, that by regulatory authority the MMS limits air emission from OCS operations (or employs offsets) to avoid significantly affecting onshore ambient air quality. Furthermore, states through their permitting authority have considerable control over wetland use. For these reasons, air pollution and wetlands costs costs may be overstated. Potential infrastructure costs (planning costs) could be relatively large for some areas, especially in remote Alaskan OCS areas and in Central and Northern California and for the Western Gulf of Mexico because of the major amount of unleased resources leasable as of mid-1987 for this OCS area.

The potential social cost estimates presented in Table III.B.2.1 are markedly smaller than the social cost estimates (called external costs) made in conjunction with the 1982 Secretarial Issue Document for the Tentative Proposed 5-Year OCS Leasing Schedule (Appendix B). In brief, the major reason for the differences in social cost estimates are that the present analysis uses updated, considerably lower oil and gas resource estimates and oil spillage rates and more recent economic and other information than was available for the 1982 study. In addition, the analysis carried out in this appendix builds upon the experience gained in the 1982 exercise and considerably extends and refines the previous study of social costs. A detailed comparison of the results of the estimation of social costs made in this Appendix with the results of the social cost analysis carried out in the 1982 study can be found in Section I.H. and is not repeated here.

Estimated Potential Regional Cost Results for Each OCS Area. In Section I of this Appendix, the concept of regional costs was introduced. As was indicated, the concept of regional costs is important when assessing the distribution of the potential costs of producing all unleased hydrocarbon resources in each area.

The concept of regional cost was introduced to indicate the estimated costs borne by residents adjacent to each OCS planning area as a result of the production of all the leasable resources unleased in all OCS areas as of mid-1987. Table III.B.2.5 summarizes the estimated aggregate regional costs for each OCS area, using the unit cost assumptions developed in Section II. Extending our use of the Western Gulf of Mexico OCS area as an example, the information in Table III.B.2.5 should be interpreted as described below.

The estimated oil spill ($27.0 million) and non-spill ($22.5 million) costs are the gross costs imposed on residents of sections adjoining the Western Gulf of Mexico resulting from oil and OCS production in all areas. However, the OCSLA provides for compensation for a wide range of damages which could result from OCS-related oil spills and for commercial fishing gear damages. Also, oil and natural gas production in the Western Gulf of Mexico and in other OCS areas replaces imports of crude oil into the area, thereby reducing foreign tanker spills. An accurate assessment of costs to residents of

Table III.B.2.5 Estimated Potential Regional Costs by Area from Development of All Areas: $29 per Barrel Starting Price (Millions of 1987 Dollars)

| AREA | (1) OIL SPILL COSTS IN REGION | (2) NON SPILL COSTS IN REGION | (3) COMPENSATION TO REGION | (4) IMPORT COSTS BACKED OUT OF REGION | (1)+(2)-(3)-(4) POTENTIAL NET COSTS TO THE REGION[a] |
|---|---|---|---|---|---|
| CGOM | 46.6 | 16.0 | 17.0 | 18.0 | 27.7 |
| WESTGOM | 27.0 | 22.5 | 9.7 | 17.9 | 21.8 |
| S.CALIF | 17.0 | 5.3 | 5.6 | 0.9 | 15.7 |
| NAVARIN | 8.7 | 9.5 | 4.3 | 0.0 | 13.9 |
| N.CALIF | 4.7 | 4.4 | 1.7 | 0.0 | 7.4 |
| EASTGOM | 5.0 | 2.9 | 1.8 | 0.1 | 6.1 |
| CEN.CALIF | 4.8 | 2.2 | 1.3 | 0.3 | 5.5 |
| S.ATLAN | 2.0 | 3.9 | 1.1 | 0.2 | 4.6 |
| ST.GEORGE | 1.2 | 3.6 | 0.6 | 0.0 | 4.2 |
| BEAUFRT | 4.2 | 1.4 | 2.0 | 0.0 | 3.6 |
| CHUKCHI | 4.2 | 0.3 | 2.0 | 0.0 | 2.5 |
| ORE/WASH | 1.5 | 0.3 | 0.3 | 0.4 | 1.2 |
| GULFALASKA | 0.5 | 0.3 | 0.2 | 0.0 | 0.7 |
| N.ATLAN | 0.1 | 0.7 | 0.1 | 0.1 | 0.6 |
| NORTON | 0.2 | 0.4 | 0.1 | 0.0 | 0.5 |
| N.ALEUTIAN | 0.2 | 0.2 | 0.1 | 0.0 | 0.3 |
| STR OF FLOR | 0.0 | 0.3 | 0.0 | 0.0 | 0.3 |
| SHUMAGIN | 0.1 | 0.0 | 0.0 | 0.0 | 0.1 |
| KODIAK | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| HOPE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| COOK INLET | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| MID-ATLAN | 1.1 | 1.3 | 0.5 | 2.1 | -0.2 |

[a] Zero costs indicated in the table occur because area contains negligible leasable resources and estimated costs are less than $0.1 million.



communities adjacent to the area, therefore, should be measured net of estimated compensation payments and net of the costs avoided by backing out foreign oil to this specific OCS area.

To estimate oil spill compensation payments to affected residents, it is assumed that 50 percent of the total of all oil spill costs--except for non-market recreation losses and the value of the lost oil, which are assumed to be non-compensable--is paid to adversely affected individuals. The 50 percent compensation rate for oil spills cannot be based on experience in this area since so little use has had to be made of the Oil Spill Pollution Fund established by the OCSLA; when experience is gained with the Fund, a 50 percent rate might prove to be too high or low. For commercial fishing gear damages, the 50 percent compensation rate used to estimate regional costs is based on recent National Marine Fisheries Service experience in administering the Fishermens Contigency Fund, Title IV of the OCSLA (Jackson, personal communication, 1986).

Total compensation payments made to residents of the Western Gulf of Mexico amount to $9.7 million, and the regional costs avoided by backing out imports is $17.9 million (columns 3 and 4 in Table III.B.2.5). The net potential regional cost for the Western Gulf of Mexico is $21.8 million in 1987 dollars. The $21.8 million figure represents the estimated net costs incurred by residents of communities adjacent to this area as a consequence of producing and transporting all of the estimated leasable resources unleased in all OCS areas as of mid-1987.

At the $29 oil starting price, net regional costs range from $27.7 million for the Central Gulf of Mexico to minus $0.2 million for the Mid-Atlantic. A negative net regional cost occurs when oil spill and non-spill cost are more than offset by compensation payments and by reduced oil spill damages from foreign tankers when imports are replaced by OCS oil and gas production. The Mid-Atlantic has a relatively high concentration of petroleum refinery facilities and is the destination for a relatively large share of imported oil (see Table III.A.2.1). For the Mid-Atlantic, OCS oil and gas production in this area, and oil production in other OCS areas, backs out a relatively large amount of imported oil. Hence, for this area, net regional costs are negative.

For the $14 initial oil price, net regional cost range from $34.4 million for the Central Gulf of Mexico to negligible for several areas (Table III.B.2.6). Net regional costs are actually higher for the Western and Central Gulf of Mexico at the $14 starting oil price. This result occurs because as the initial oil price is decreased from $29 to $14, the amount of natural gas leasable in the Western Gulf of Mexico, and in general the amount of resources available in all areas, drops. As a result, more oil is imported and spillage from foreign tankers is greater. This is illustrated by comparing, for example, the costs avoided in the Western Gulf of Mexico by backing out imported oil at the $29 oil price ($17.9 million) with the import-related oil spill costs avoided at the $14 price ($8.4 million).

<u>Social Cost Sensitivity Analysis</u>. In previous sections of this appendix, the many uncertainties inherent in the analysis of estimated potential social costs have been described. The uncertainties include the magnitude, composition and location of leasable oil and gas resources unleased as of mid-1987, the precise location and timing of oil spills and the unit costs which could be associated with oil spills and non-

Table III.B.2.6 Estimated Potential Regional Costs by Area from Development of All Areas: $14 per Barrel Starting Price (Millions of 1987 Dollars)

| AREA | (1) OIL SPILL COSTS IN REGION | (2) NON SPILL COSTS IN REGION | (3) COMPENSATION TO REGION | (4) IMPORT COSTS BACKED OUT OF REGION | (1)+(2)-(3)-(4) POTENTIAL NET COSTS TO THE REGION[a] |
|---|---|---|---|---|---|
| CGOM | 44.6 | 15.6 | 16.2 | 9.6 | 34.4 |
| WESTGOM | 22.1 | 18.9 | 8.0 | 8.4 | 24.5 |
| S.CALIF | 7.2 | 2.8 | 2.3 | 0.4 | 7.3 |
| N.CALIF | 2.0 | 2.7 | 0.7 | 0.0 | 3.9 |
| EASTGOM | 1.9 | 1.8 | 0.7 | 0.0 | 3.0 |
| CEN.CALIF | 2.4 | 1.4 | 0.6 | 0.1 | 3.0 |
| S.ATLAN | 0.7 | 1.7 | 0.4 | 0.1 | 1.9 |
| ORE/WASH | 0.6 | 0.2 | 0.1 | 0.2 | 0.5 |
| N.ATLAN | 0.0 | 0.5 | 0.0 | 0.1 | 0.4 |
| MID-ATLAN | 0.5 | 0.8 | 0.3 | 1.0 | 0.1 |
| NAVARIN | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| BEAUFRT | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| CHUKCHI | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| ST.GEORGE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| N.ALEUTIAN | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| GULFALASKA | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| NORTON | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| KODIAK | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| HOPE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SHUMAGIN | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| COOK INLET | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| STR OF FLOR | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

[a] Zero costs indicated in the table occur because area contains negligible leasable resources and estimated costs are less than $.1 million.



spill adverse effects. In recognition of the many uncertainties necessarily involved in the analysis of social costs, a sensitivity analysis was carried out. The purpose of the sensitivity analysis was to gain an appreciation of how the cost estimates for OCS planning areas presented in section III.B.2 and I.G might change in response to changes in some of the data or assumptions used in the analysis.

The sensitivity analyses examine how the social cost estimates presented in sections III.B.2 and I.G change when individual, potential oil spill and non-spill costs are assumed to take on even higher values than the conservative (i.e., high) estimates developed in Section II. It is emphasized that the basis for comparison of all sensitivity analyses is the social cost results for the $29 starting oil price case presented in sections III.B.2 and I.G.

Wetlands, ecological and commercial fishing industry losses were selected for the sensitivity analyses because these costs are potentially quantitatively significant and inherently difficult to estimate. The sensitivity analysis cases considered ranged from one set of results in which each of the individual costs was allowed to be 25 percent greater than the unit cost estimates presented in Section II to an extreme case in which all of the three unit costs were assumed to be 50 percent greater than the unit costs developed in Section II.

Table III.B.2.7 summarizes the potential social costs by area for the extreme sensitivity analysis case, using the resource estimates for the $29 initial oil price case. In general, the sensitivity analysis leads to a less than 30 percent increase in total discounted net social costs. This is because (1) only a subset of all costs is assumed to increase and (2) when individual oil spill costs increase, the social cost savings from backing out imported oil also increase, thereby moderating the net increase in total potential social costs. The extreme sensitivity analysis results lead to no changes in the ranking of the ten major OCS areas in terms of their total potential social costs. Table III.B.2.8 presents the extreme sensitivity analysis results for the $14 per barrel of oil starting price.

3. Changes in Social Cost Estimates Resulting from Proposed Sub-Area Deferrals and Coastal Deferral Alternatives to the Proposed Program

This section examines the net social costs associated with each of the proposed sub-area deferrals and the coastal deferall alternatives to the proposed program. A total of twenty sub-area deferrals have been proposed for the Atlantic, California and Alaskan OCS planning areas (see Tables II.B.3.1 and II.B.3.2). Each of the sub-area deferrals results in a reduction in the estimated amount of leasable oil and natural gas resources. For each sub-area deferral, the amount by which estimated leasable resources is reduced depends on the starting price for oil, so that 40 individual cases need to be considered--twenty each for the $14 and the $29 initial oil price assumption.

When the amount of leasable resources in an OCS area is reduced because of a sub-area deferral, the social costs associated with OCS operations decline. However, the social costs avoided by this reduction in OCS leasable resources is somewhat offset by an increase in social costs from oil spills from the additional imports presumed to occur when

Table III.B.2.7 Summary of the Present Discounted Value of Estimated Potential Social Costs for Each OCS Planning Area: $29 per Barrel Starting Price (Millions of 1987 dollars)

SENSITIVITY ANALYSIS: Extreme High Estimates for Commercial Fisheries, Wetlands and Ecological Costs
Commercial Fisheries Costs * 1.5
Wetlands Costs * 1.5
Ecological Costs * 1.5

| AREA | (1) OIL SPILL COSTS | (2) NON SPILL COSTS | (3)=(1)+(2) GROSS SOCIAL COSTS | (4) LESS: COST AVOIDED FROM REDUCED IMPORTS[a] | (5)=(3)-(4) TOTAL NET DISCOUNTED SOCIAL COSTS[b] |
|---|---|---|---|---|---|
| CGOM | 41.1 | 19.3 | 60.5 | 9.7 | 50.8 |
| WESTGOM | 21.7 | 23.8 | 45.4 | 6.8 | 38.7 |
| NAVARIN | 10.6 | 9.9 | 20.4 | 3.7 | 16.7 |
| S.CALIF | 13.1 | 5.6 | 18.8 | 5.0 | 13.8 |
| N.CALIF | 3.9 | 5.1 | 9.0 | 1.7 | 7.3 |
| EASTGOM | 4.3 | 3.4 | 7.7 | 1.3 | 6.5 |
| S.ATLAN | 2.4 | 4.2 | 6.7 | 0.9 | 5.7 |
| BEAUFRT | 5.2 | 1.9 | 7.2 | 1.7 | 5.5 |
| ST.GEORGE | 1.5 | 4.0 | 5.5 | 0.6 | 4.9 |
| CEN.CALIF | 2.9 | 2.5 | 5.4 | 1.3 | 4.1 |
| CHUKCHI | 5.1 | 0.3 | 5.4 | 1.8 | 3.6 |
| MID-ATLAN | 1.3 | 1.5 | 2.7 | 0.4 | 2.4 |
| N.ATLAN | 0.2 | 0.9 | 1.1 | 0.1 | 1.0 |
| ORE/WASH | 0.3 | 0.3 | 0.6 | 0.1 | 0.5 |
| N.ALEUTIAN | 0.2 | 0.2 | 0.5 | 0.1 | 0.4 |
| NORTON | 0.3 | 0.4 | 0.7 | 0.1 | 0.6 |
| GULFALASKA | 0.2 | 0.3 | 0.6 | 0.0 | 0.5 |
| STR OF FLO | 0.1 | 0.5 | 0.6 | 0.0 | 0.5 |
| KODIAK | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| HOPE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SHUMAGIN | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| COOK INLET | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

[a] Estimated Potential Social costs avoided to the nation as a whole from reduced needs for imported oil, assuming reduced imports (and associated oil spills) are distributed across OCS planning areas in the same proportion as indicated in Table III.A.3.1.
[b] Zero costs indicated in the table occur because area contains negligible leasable resources and estimated costs are less than $.1 million.



Table III.B.2.8 Summary of the Present Discounted Value of Estimated Potential Social Costs for Each OCS Planning Area: $14 per Barrel Starting Price (Millions of 1987 dollars)

SENSITIVITY ANALYSIS: Extreme High Estimates for Commercial Fisheries, Wetlands and Ecological Costs
Commercial Fisheries Costs * 1.5
Wetlands Costs * 1.5
Ecological Costs * 1.5

| AREA | (1) OIL SPILL COSTS | (2) NON SPILL COSTS | (3)=(1)+(2) GROSS SOCIAL COSTS | (4) LESS: COST AVOIDED FROM REDUCED IMPORTS[a] | (5)=(3)-(4) TOTAL NET DISCOUNTED SOCIAL COSTS[b] |
|---|---|---|---|---|---|
| CGOM | 39.3 | 18.9 | 58.3 | 8.0 | 50.2 |
| WESTGOM | 17.7 | 20.1 | 37.9 | 4.8 | 33.1 |
| S.CALIF | 5.6 | 3.1 | 8.7 | 1.8 | 6.9 |
| N.CALIF | 1.7 | 3.4 | 5.1 | 0.7 | 4.4 |
| EASTGOM | 1.6 | 2.3 | 4.0 | 0.4 | 3.5 |
| S.ATLAN | 0.8 | 2.0 | 2.9 | 0.3 | 2.6 |
| CEN.CALIF | 1.5 | 1.7 | 3.2 | 0.6 | 2.6 |
| MID-ATLAN | 0.6 | 0.9 | 1.6 | 0.1 | 1.4 |
| N.ATLAN | 0.0 | 0.7 | 0.7 | 0.0 | 0.7 |
| ORE/WASH | 0.3 | 0.2 | 0.5 | 0.1 | 0.4 |
| NAVARIN | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| BEAUFRT | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| CHUKCHI | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| ST.GEORGE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| N.ALEUTIAN | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| GULFALASKA | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| NORTON | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| KODIAK | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| HOPE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SHUMAGIN | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| COOK INLET | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| STR OF FLOR | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

[a] Estimated Potential Social costs avoided to the nation as a whole from reduced needs for imported oil, assuming reduced imports (and associated oil spills) are distributed across OCS planning areas in the same proportion as indicated in Table III.A.3.1.
[b] Zero costs indicated in the table occur because area contains negligible leasable resources and estimated costs are less than $.1 million.

smaller amounts of OCS oil and gas are produced. In sum, just as net social cost is the relevant concept for measuring costs to the Nation as a whole from additional OCS operations, so too, net social cost is the relevant concept for measuring costs avoided to the Nation as a whole from a reduction in leasable resources.

Using the methodology, data and assumptions described in Sections II and III, the net social cost and the net social cost per BBOE have been estimated for each proposed sub-area deferral for each of the relevant OCS planning areas. In addition, the net regional cost has been estimated for each sub-area deferral case. Table III.B.3.1 and Table III.B.3.2 present the results for the $29 and $14 oil starting prices, respectively. Using So. California as an example, at a $29 oil starting price under the Deukmejian proposal the estimated amount of leasable resources is .494 BBOE, and the social costs associated with developing, producing and transporting this amount of resources is $7.7 million (Table III.B.3.1). However, the estimated net social cost of developing, producing and transporting all of this area's estimated leasable resources of .82 BBOE--the amount with no sub-area deferral--is $12.3 million (see Table III.B.2.1). Hence, the change in net social cost in this particular case is $4.6 million.

In addition to subarea deferrals which reduce the resource estimate for an OCS planning area, a number of large coastal deferral alternatives have been proposed which do not change resource estimates. However, many of the coastal deferral alternatives have a significant affect on the value of the marine productivity and sensitivity scores calculated for OCS planning areas (see Section I). Consequently, the associated ecological cost per barrel of oil spilled, used to determine social costs, also changes for those areas. To assess the impact of these coastal deferrals on social costs, the ecological cost and the resulting social cost have been estimated to reflect the appropriate marine productivity and sensitivity scores. These results are presented in Table III.B.3.3 for each relevant OCS planning area for each deferral alternative. For example, for the South Atlantic, exclusion of the coastal buffer from leasing reduces the ecological score for this OCS area from 230 to 125. As a result, the net social cost for this area is $4.531 million as compared to $5.0 million at the $29 oil starting price (see Table III.B.2.1). The appropriate net social cost measure for each OCS planning area for which one or more coastal deferral alternatives have been proposed is summarized in Table III.B.3.3. for each of the two starting oil prices.



Table III.B.3.1 Net Social Costs for Selected Sub-Area Deferral Proposals: $29 per Barrel Starting Price (Millions of 1987 Dollars)

| | BBOE | Net Social Cost | Net Cost per BBOE | Net Regional Costs |
|---|---|---|---|---|
| Congressional Moritorium Area | | | | |
| No. Atlantic | 0.052 | $0.7 | $12.7 | $0.6 |
| 15 Mile Buffer and Low Potential Areas | | | | |
| No. Atlantic | 0.067 | $0.7 | $10.8 | $0.6 |
| NASA Flight Zone | | | | |
| So. Atlantic | 0.640 | $4.3 | $6.7 | $3.9 |
| 1,000 Meter Isobath | | | | |
| So. California | 0.807 | $12.1 | $15.1 | $15.3 |
| Cen California | 0.222 | $3.5 | $15.9 | $5.4 |
| No. California | 0.371 | $5.8 | $15.8 | $6.8 |
| Governer's Proposal | | | | |
| So. California | 0.494 | $7.7 | $15.7 | $8.9 |
| Cen California | 0.155 | $2.2 | $14.4 | $4.2 |
| No. California | 0.356 | $5.0 | $14.0 | $6.8 |
| Regula Proposal | | | | |
| So. California | 0.768 | $11.6 | $15.1 | $14.5 |
| Cen California | 0.220 | $3.0 | $13.4 | $5.3 |
| No. California | 0.247 | $4.2 | $17.2 | $5.1 |
| Paneta Proposal | | | | |
| So. California | 0.645 | $9.9 | $15.4 | $11.9 |
| Cen California | 0.046 | $1.0 | $22.4 | $2.3 |
| No. California | 0.106 | $2.5 | $23.6 | $3.8 |
| Amalgamated Proposal | | | | |
| So. California | 0.771 | $11.2 | $14.6 | $14.7 |
| Cen California | 0.225 | $3.5 | $15.7 | $5.5 |
| No. California | 0.331 | $5.3 | $16.0 | $6.2 |
| Institute for Resource Management Proposal | | | | |
| St George Basin | 0.230 | $3.7 | $15.9 | $3.8 |
| Norton Basin | 0.010 | $0.3 | $25.8 | $0.3 |

Table III.B.3.2 Net Social Costs for Selected Sub-Area Deferral Proposals: $14 per Barrel Starting Price (Millions of 1987 Dollars)

| | BBOE | Net Social Cost | Net Cost per BBOE | Net Regional Costs |
|---|---|---|---|---|
| Congressional Moritorium Area | | | | |
| No. Atlantic | 0.006 | $0.5 | $76.1 | $0.4 |
| 15 Mile Buffer and Low Potential Areas | | | | |
| No. Atlantic | 0.009 | $0.5 | $52.2 | $0.4 |
| NASA Flight Zone | | | | |
| So. Atlantic | 0.152 | $1.5 | $9.8 | $1.5 |
| 1,000 Meter Isobath | | | | |
| So. California | 0.372 | $5.9 | $16.0 | $6.6 |
| Cen California | 0.117 | $2.1 | $18.0 | $3.0 |
| No. California | 0.133 | $3.0 | $22.8 | $3.2 |
| Governor's Proposal | | | | |
| So. California | 0.237 | $4.0 | $17.0 | $3.7 |
| Cen California | 0.079 | $1.4 | $17.6 | $2.9 |
| No. California | 0.133 | $2.8 | $20.8 | $4.1 |
| Regula Proposal | | | | |
| So. California | 0.334 | $5.4 | $16.1 | $5.8 |
| Cen California | 0.114 | $1.8 | $15.6 | $3.5 |
| No. California | 0.112 | $2.7 | $24.3 | $3.2 |
| Paneta Proposal | | | | |
| So. California | 0.281 | $4.7 | $16.6 | $4.5 |
| Cen California | 0.023 | $0.8 | $33.7 | $1.9 |
| No. California | 0.013 | $1.6 | $122.2 | $2.7 |
| Amalgamated Proposal | | | | |
| So. California | 0.336 | $5.2 | $15.6 | $6.5 |
| Cen California | 0.117 | $2.1 | $17.9 | $3.1 |
| No. California | 0.154 | $3.2 | $21.1 | $3.6 |
| Institute for Resource Management Proposal | | | | |
| St George Basin | 0.000 | $0.0 | $0.0 | $.0 |
| Norton Basin | 0.000 | $0.0 | $0.0 | $.0 |



Table III.B.3.3 Present Discounted Value of Estimated Potential Social Costs with Lower Ecological Score due to Various Deferral Options ($29 per Barrel Starting Price)

| | Old Ecological Score | New Ecological Score | Net Social Costs ($ Million) |
|---|---|---|---|
| North Atlantic | | | |
| Coastal Buffer | 209 | 116 | $0.729 |
| Cumulative | 209 | 98 | $0.729 |
| Mid Atlantic | | | |
| Cumulative | 198 | 118 | $1.859 |
| South Atlantic | | | |
| Coastal Buffer | 230 | 125 | $4.531 |
| Cumulative | 230 | 124 | $4.531 |
| Straits of Florida | | | |
| Atlantic Coast | 234 | 246 | $0.366 |
| Easter Gulf of Mexico | | | |
| Seagrass Beds & Middle Ground | 208 | 189 | $5.436 |
| Coastal Buffer | 208 | 137 | $5.074 |
| Apalachicola | 208 | 202 | $5.534 |
| Miami Map | 208 | 186 | $5.413 |
| Cumulative | 208 | 137 | $5.074 |
| Washington-Oregon | | | |
| Cumulative | 256 | 116 | $0.414 |
| St. George Basin | | | |
| Unimak Pass | 281 | 267 | $4.323 |
| North Aleutian Basin | | | |
| Unimak Pass | 327 | 326 | $0.375 |
| Norton Basin | | | |
| Yukon Delta Coastal | 280 | 259 | $0.589 |
| Beaufort Sea | | | |
| Point Barrow | 261 | 257 | $4.389 |

## FOOTNOTES

1/All monetary results are presented in constant dollars as of mid-1987. All dollar values were converted to 1985 dollars using the gross national product implicit price deflator; these values were then converted to mid-1987 dollars, assuming a 5 percent rate of inflation for 1986 and 1987.

2/The judgment that OCS oil replaces imports on a barrel-for-barrel basis is quite reasonable. Since additional OCS production on the scale envisioned does not affect the price of oil, the same quantity of refined petroleum products will be consumed with or without the additional OCS oil production. Thus, OCS oil replaces imported oil, which provides the marginal supply to the U.S. Any conservation induced by non-price factors complements, and does not substitute for, OCS oil in reducing imports. OCS oil and domestic alternative energy sources are not substitutes since neither OCS oil nor alternative energy sources affect the price of oil.

OCS natural gas will replace imported oil (or refined products like residual fuel). The analysis in the text assumes that substitution occurs with 1 Btu of OCS natural gas replacing 1/2 Btu of imported oil. Since the actual substitution ratio may be 1 to 1 (Hochheiser, personal communication, August 6, 1986), the assumption that OCS gas replaces imported oil on a 1 to 1/2 basis leads to a conservative (i.e., high) estimate of net social costs.

3/The conversion rate used is 5.62 MCF = 1 barrel of oil, based on Btu equivalents.

4/The estimate of the average size of pipeline spills is dominated by the 160,638 barrel West Delta 73 spill in 1967. Excluding this incident, the average pipeline spill is 6,700. This value in fact may be a more reasonable number for estimating social costs than the average pipeline spill size of 25,937 used in the text. However, use of the average spill size for pipelines is consistent with the approach taken for tanker and platform spills and also is consistent with the standard of providing a conservative or high estimate of social cost. It is emphasized that the use of this high average pipeline spill size is intended to serve the purpose of developing a conservative estimate of social costs--it is not intended to provide a rationale for choosing between tankers or pipelines to transport oil in any particular case.

5/A study of the 1979 IXTOC I oil spill could find no evidence of economic damages to domestic fisheries. (U.S. Dept. of Interior, 1982, p.181). These results are not used in the cost calculations for commerical fisheries made in this analysis.

6/ An alternative approach for estimating commercial fishery (and other natural resource) damages is provided by a new methodology developed under CERCLA to measure damages from injury to natural resources from oil and hazardous substance spills. This methodology uses an integrated, interdisciplinary model to measure natural resource damages from spills. Use of this approach--the Natural Resources Damage Assessment Model for Coastal and Marine Environments (NRDAM/CME)--to estimate social costs is described in Attachment E as a sensitivity



analysis. The results in Attachment E indicate that use of the NRDAM/CME leads to lower natural resource damages for 18 of the 22 OCS planning areas than when the simplified approach described in Section II is used.

7/This finding conflicts with that of Restrepo and Associates (1982, pp. 9-13) who concluded that Texas coastal tourism businesses lost some 12 million dollars as a result of the IXTOC I spill. However, the Freeman, Holland and Ditton analysis is viewed as more accurate because it is based on visitation data and allowed for the influence of factors other than the oil spill which may have contributed to tourism losses (gasoline availability and price), while the Restrepo et al. results were based on interviews with businesses.

8/The losses estimated by Wilman are stated in present value terms, using a 10 percent discount rate, and all spills are assumed to occur in year 8. The per barrel estimates cited in the text were estimated by first determining the value at time zero of the present value sums indicated by Wilman (p. 139) and then dividing this figure by the number of barrels spilled in her examples.

9/As noted in footnote 6, a new methodology developed under CERCLA provides an alternative approach for estimating ecological and other natural resource damages from oil and hazardous substance spills. A sensitivity analysis presented in Attachment E indicates lower damages for all but four OCS areas when the NRDAM/CME methodology is used as compared with estimates developed for the the simplified approach described in Section II.

10/This element of the claim for damages was later disallowed in court proceedings on the grounds that as a practical matter, the organisms lost would not actually be replaced.

11/The $319.7 is a high or overstated cost to use in this analysis because the replacement cost used by Sorensen to value each dead organism was based on the market value, which is considerably higher than the in situ value of organisms in the marine environment (before harvesting, processing, advertising costs, etc. and a normal profit are included). Also, mangrove environments appear to be particularly productive biologically (92 million organisms killed vs. 65 million for the much larger AMOCO CADIZ oil spill).

12/ The new methodology developed under CERCLA to measure damages from injury to natural resources from oil and hazardous substance spills could be used to provide insight into some possible subsistence losses (e.g., waterfowl and fur seals). The results of the sensitivity analysis in Attachment E indicate lower damages for 8 of the 10 coastal Alaskan OCS areas when the NRDAM/CME, rather than the simplified approach described in Section II, is used.

13/It is noted that the potential threat to air quality from OCS operations varies considerably among the several pollutants associated with OCS oil and gas activities and varies considerably within a planning area.

14/The regional recreational statistics presented in this publication were disaggregated on the basis of population to conform to OCS planning areas. Alaska was assumed to have the same number of recreational fishing days per capita as the Washington-Oregon planning area.

15/No estimate has yet been made of the probability of a spill on the Washington-Oregon OCS striking land. In the absence of this information, we have assumed that the chance of a spill striking the Washington/Oregon coast is the average of the chance for the No. California and Gulf of Alaska areas.

16/In the event of an excess supply of crude oil on the West Coast over the period of concern, some oil will be shipped via the Panama Canal to petroleum refineries on the Gulf of Mexico and East Coast. Whether or not excess supplies of oil will occur depends upon a myriad of factors: the price of oil, leasing policy, OCS and onshore discoveries and production relative to demand, and other factors (see Norgaard and Hall, 1984). In the face of these uncertainties, we have assumed that West Coast and Alaskan OCS oil is offloaded and either refined on the West Coast or shipped via a trans-state pipeline to refineries in Texas.



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ATTACHMENT A

Description of Procedure and Data Used to Estimate
Annual Oil and Natural Gas Production for
Each Planning Area

Estimates of annual production of oil and gas were developed using area specific information from the Department of the Interior on

(1) total leasable resources.

(2) years from lease sle to initial production.

(3) years from initial production to final production

(4) years from initial production to peak production.

(5) production in the peak year as a percentage of total production.

Production in each area is presumed to increase at a percentage rate of growth from initial to peak production, and then decline from the peak year to the final year of production at that same percentage rate. That is, production in area i during some year, t, can be expressed as:

$$P_i(t) = [1/1+g_i]^{t_p - t} P_i(t_p)$$

where $P_i(t)$ is production in area i in year t, $g_i$ is the area specific growth rate (or decline) and $t_p$ is the peak year of production. A search procedure is employed to determine the value of $g_i$ for each area so the total produciton over the productive life of the area is equal to the Interior's estimate of total reserves.

Area-specific data for each item (1)-(5) above are presented in the following two tables for the low and high oil starting prices.



ATTACHMENT A
$29 per Barrel Oil

| AREA | YRS TO PROD | YRS TO PEAK | PEAK AS PRD | TOTYEARS OF PROD | OIL | GAS | BBOE |
|---|---|---|---|---|---|---|---|
| CGOM | 2.00 | 17.00 | 6.00 | 38.00 | 1.67 | 2.44 | 4.11 |
| WESTGOM | 3.00 | 18.00 | 6.00 | 38.00 | 1.32 | 3.31 | 4.63 |
| S.CALIF | 6.00 | 7.00 | 11.00 | 30.00 | 0.65 | 0.17 | 0.82 |
| S.ATLAN | 9.00 | 5.00 | 9.00 | 27.00 | 0.15 | 0.62 | 0.77 |
| NAVARIN | 10.00 | 4.00 | 8.00 | 25.00 | 0.65 | 0.14 | 0.79 |
| EASTGOM | 6.00 | 17.00 | 6.00 | 25.00 | 0.24 | 0.23 | 0.47 |
| BEAUFRT | 11.00 | 4.00 | 8.00 | 25.00 | 0.31 | 0.00 | 0.31 |
| CHUKCHI | 13.00 | 4.00 | 8.00 | 25.00 | 0.40 | 0.00 | 0.40 |
| CEN.CALIF | 6.00 | 7.00 | 10.00 | 27.00 | 0.17 | 0.06 | 0.23 |
| N.CALIF | 6.00 | 7.00 | 10.00 | 27.00 | 0.23 | 0.18 | 0.41 |
| ST.GEORGE | 10.00 | 4.00 | 8.00 | 25.00 | 0.11 | 0.15 | 0.26 |
| MID-ATLAN | 9.00 | 4.00 | 9.00 | 27.00 | 0.06 | 0.17 | 0.23 |
| N.ATLAN | 11.00 | 6.00 | 7.00 | 27.00 | 0.02 | 0.05 | 0.07 |
| ORE/WASH | 6.00 | 7.00 | 9.00 | 25.00 | 0.02 | 0.04 | 0.06 |
| N.ALEUTIAN | 9.00 | 4.00 | 8.00 | 19.00 | 0.01 | 0.01 | 0.02 |
| GULFALASKA | 10.00 | 4.00 | 8.00 | 19.00 | 0.01 | 0.02 | 0.03 |
| NORTON | 6.00 | 4.00 | 10.00 | 20.00 | 0.01 | 0.01 | 0.02 |
| KODIAK | 9.00 | 4.00 | 8.00 | 25.00 | 0.00 | 0.00 | 0.00 |
| HOPE | 13.00 | 4.00 | 8.00 | 25.00 | 0.00 | 0.00 | 0.00 |
| SHUMAGIN | 9.00 | 4.00 | 8.00 | 25.00 | 0.00 | 0.00 | 0.00 |
| COOK INLET | 9.00 | 4.00 | 8.00 | 19.00 | 0.00 | 0.00 | 0.00 |
| STR OF FLORIDA | 9.00 | 6.00 | 8.00 | 21.00 | 0.00 | 0.00 | 0.01 |

ATTACHMENT A (Cont)
$14 per Barrel Oil

| AREA | YRS TO PROD | YRS TO PEAK | PEAK AS PRD | TOTYEARS OF PROD | OIL | GAS | BBOE |
|---|---|---|---|---|---|---|---|
| CGOM | 2.00 | 17.00 | 6.00 | 38.00 | 1.60 | 2.33 | 3.93 |
| WESTGOM | 3.00 | 18.00 | 6.00 | 38.00 | 1.08 | 2.71 | 3.79 |
| S.CALIF | 6.00 | 7.00 | 11.00 | 30.00 | 0.28 | 0.10 | 0.38 |
| S.ATLAN | 9.00 | 5.00 | 9.00 | 27.00 | 0.05 | 0.20 | 0.25 |
| NAVARIN | 10.00 | 4.00 | 8.00 | 25.00 | 0.00 | 0.00 | 0.00 |
| EASTGOM | 6.00 | 17.00 | 6.00 | 25.00 | 0.09 | 0.09 | 0.18 |
| BEAUFRT | 11.00 | 4.00 | 8.00 | 25.00 | 0.00 | 0.00 | 0.00 |
| CHUKCHI | 13.00 | 4.00 | 8.00 | 25.00 | 0.00 | 0.00 | 0.00 |
| CEN.CALIF | 6.00 | 7.00 | 10.00 | 27.00 | 0.09 | 0.03 | 0.12 |
| N.CALIF | 6.00 | 7.00 | 10.00 | 27.00 | 0.10 | 0.08 | 0.18 |
| ST.GEORGE | 10.00 | 4.00 | 8.00 | 25.00 | 0.00 | 0.00 | 0.00 |
| MID-ATLAN | 9.00 | 4.00 | 9.00 | 27.00 | 0.03 | 0.08 | 0.11 |
| N.ATLAN | 11.00 | 6.00 | 7.00 | 27.00 | 0.00 | 0.01 | 0.01 |
| ORE/WASH | 6.00 | 7.00 | 9.00 | 25.00 | 0.01 | 0.04 | 0.05 |
| N.ALEUTIAN | 9.00 | 4.00 | 8.00 | 19.00 | 0.00 | 0.00 | 0.00 |
| GULFALASKA | 10.00 | 4.00 | 8.00 | 19.00 | 0.00 | 0.00 | 0.00 |
| NORTON | 6.00 | 4.00 | 10.00 | 20.00 | 0.00 | 0.00 | 0.00 |
| KODIAK | 9.00 | 4.00 | 8.00 | 25.00 | 0.00 | 0.00 | 0.00 |
| HOPE | 13.00 | 4.00 | 8.00 | 25.00 | 0.00 | 0.00 | 0.00 |
| SHUMAGIN | 9.00 | 4.00 | 8.00 | 25.00 | 0.00 | 0.00 | 0.00 |
| COOK INLET | 9.00 | 4.00 | 8.00 | 19.00 | 0.00 | 0.00 | 0.00 |
| STR OF FLORIDA | 9.00 | 6.00 | 8.00 | 21.00 | 0.00 | 0.00 | 0.00 |



[illegible] B
Present d[illegible] oted [illegible] [illegible]ll costs by category and
source f[illegible] oducin[illegible] [illegible]able resources unleased
as of [illegible] [illegible] $29 p[illegible] arrel [illegible] Price
million 1987 do[illegible]

CGOM

| SOURCE | CLEAN & CONTROL | COM[illegible] DIREC[illegible] COSTS | [illegible]ARY [illegible]S | T[illegible] R[illegible] | ECOLOG [illegible]STS | SUBSIST COSTS | LOST OIL | OTHER COSTS | TOTAL COSTS | COST/ BBL SPILL | COST/BBO HANDLED |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PLATFORM | 2.08 | 1.43 | [illegible] | 5.[illegible] | 2.16 | 0.00 | 0.39 | 0.34 | 13.02 | 351.60 | 7.78 |
| PIPELINE | 2.94 | 2.14 | [illegible] | 8.[illegible] | 3.23 | 0.00 | 0.59 | 0.50 | 19.34 | 348.32 | 14.46 |
| TANKERS | 0.36 | 0.25 | 0.2[illegible] | 1.0[illegible] | 0.37 | 0.00 | 0.07 | 0.06 | 2.33 | 364.36 | 6.97 |

WESTGOM

| SOURCE | CLEAN & CONTROL | COMMERCIAL FISH DIRECT COSTS | COMMERCIAL FISH SECONDARY COSTS | TOUR & RECRE | ECOLOG COSTS | SUBSIST COSTS | LOST OIL | OTHER COSTS | TOTAL COSTS | COST/ BBL SPILL | COST/BBO HANDLED |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PLATFORM | 1.42 | 0.57 | 0.50 | 3.56 | 0.79 | 0.00 | 0.28 | 0.23 | 7.36 | 251.79 | 5.57 |
| PIPELINE | 1.86 | 0.80 | 0.70 | 5.01 | 1.11 | 0.00 | 0.39 | 0.33 | 10.21 | 248.46 | 10.31 |
| TANKERS | 0.30 | 0.12 | 0.11 | 0.86 | 0.17 | 0.00 | 0.06 | 0.05 | 1.67 | 265.15 | 5.07 |

S. CALIF

| SOURCE | CLEAN & CONTROL | COMMERCIAL FISH DIRECT COSTS | COMMERCIAL FISH SECONDARY COSTS | TOUR & RECRE | ECOLOG COSTS | SUBSIST COSTS | LOST OIL | OTHER COSTS | TOTAL COSTS | COST/ BBL SPILL | COST/BBO HANDLED |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PLATFORM | 0.89 | 0.17 | 0.45 | 1.79 | 0.81 | 0.00 | 0.20 | 0.17 | 4.47 | 310.06 | 6.86 |
| PIPELINE | 0.95 | 0.21 | 0.56 | 2.21 | 1.01 | 0.00 | 0.24 | 0.21 | 5.39 | 301.97 | 12.53 |
| TANKERS | 0.25 | 0.05 | 0.13 | 0.69 | 0.24 | 0.00 | 0.06 | 0.05 | 1.46 | 345.43 | 6.60 |

S. ATLAN

| SOURCE | CLEAN & CONTROL | COMMERCIAL FISH DIRECT COSTS | COMMERCIAL FISH SECONDARY COSTS | TOUR & RECRE | ECOLOG COSTS | SUBSIST COSTS | LOST OIL | OTHER COSTS | TOTAL COSTS | COST/ BBL SPILL | COST/BBO HANDLED |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PLATFORM | 0.11 | 0.06 | 0.05 | 0.03 | 0.18 | 0.00 | 0.04 | 0.03 | 0.49 | 148.09 | 3.28 |
| PIPELINE | 0.13 | 0.10 | 0.10 | 0.05 | 0.33 | 0.00 | 0.07 | 0.06 | 0.84 | 136.17 | 5.65 |
| TANKERS | 0.08 | 0.05 | 0.04 | 0.19 | 0.15 | 0.00 | 0.03 | 0.03 | 0.58 | 203.19 | 3.88 |

NAVARIN

| SOURCE | CLEAN & CONTROL | COMMERCIAL FISH DIRECT COSTS | COMMERCIAL FISH SECONDARY COSTS | TOUR & RECRE | ECOLOG COSTS | SUBSIST COSTS | LOST OIL | OTHER COSTS | TOTAL COSTS | COST/ BBL SPILL | COST/BBO HANDLED |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PLATFORM | 0.71 | 0.03 | 0.04 | 0.10 | 0.17 | 0.00 | 0.15 | 0.13 | 1.34 | 93.57 | 2.07 |
| PIPELINE | 0.96 | 0.06 | 0.07 | 0.19 | 0.33 | 0.00 | 0.28 | 0.24 | 2.13 | 79.46 | 3.30 |
| TANKERS | 1.88 | 0.15 | 0.34 | 2.17 | 1.05 | 0.00 | 0.26 | 0.22 | 6.07 | 246.04 | 4.70 |

ATTACHMENT B (CONT)

### EASTGOM

| SOURCE | CLEAN & CONTROL | COMMERCIAL FISH DIRECT COSTS | COMMERCIAL FISH SECONDARY COSTS | TOUR & RECRE | ECOLOG COSTS | SUBSIST COSTS | LOST OIL | OTHER COSTS | TOTAL COSTS | COST/ BBL SPILL | COST/BBO HANDLED |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PLATFORM | 0.22 | 0.05 | 0.04 | 0.40 | 0.20 | 0.00 | 0.05 | 0.04 | 0.99 | 184.25 | 4.08 |
| PIPELINE | 0.34 | 0.09 | 0.08 | 0.74 | 0.37 | 0.00 | 0.10 | 0.08 | 1.80 | 178.05 | 7.39 |
| TANKERS | 0.18 | 0.04 | 0.03 | 0.48 | 0.17 | 0.00 | 0.05 | 0.04 | 0.98 | 211.71 | 4.05 |

### BEAUFRT

| SOURCE | CLEAN & CONTROL | COMMERCIAL FISH DIRECT COSTS | COMMERCIAL FISH SECONDARY COSTS | TOUR & RECRE | ECOLOG COSTS | SUBSIST COSTS | LOST OIL | OTHER COSTS | TOTAL COSTS | COST/ BBL SPILL | COST/BBO HANDLED |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PLATFORM | 0.34 | 0.00 | 0.00 | 0.07 | 0.38 | 0.25 | 0.07 | 0.06 | 1.17 | 170.54 | 3.78 |
| PIPELINE | 0.49 | 0.00 | 0.00 | 0.13 | 0.72 | 0.47 | 0.13 | 0.11 | 2.04 | 158.60 | 6.58 |
| TANKERS | 0.28 | 0.04 | 0.09 | 0.46 | 0.24 | 0.06 | 0.06 | 0.05 | 1.28 | 215.61 | 4.12 |

### CHUKCHI

| SOURCE | CLEAN & CONTROL | COMMERCIAL FISH DIRECT COSTS | COMMERCIAL FISH SECONDARY COSTS | TOUR & RECRE | ECOLOG COSTS | SUBSIST COSTS | LOST OIL | OTHER COSTS | TOTAL COSTS | COST/ BBL SPILL | COST/BBO HANDLED |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PLATFORM | 0.38 | 0.00 | 0.00 | 0.07 | 0.28 | 0.27 | 0.08 | 0.06 | 1.14 | 129.08 | 2.86 |
| PIPELINE | 0.54 | 0.00 | 0.00 | 0.14 | 0.52 | 0.52 | 0.14 | 0.12 | 1.97 | 118.77 | 4.93 |
| TANKERS | 0.31 | 0.05 | 0.10 | 0.51 | 0.24 | 0.08 | 0.07 | 0.05 | 1.41 | 184.79 | 3.53 |

### CEN. CALIF

| SOURCE | CLEAN & CONTROL | COMMERCIAL FISH DIRECT COSTS | COMMERCIAL FISH SECONDARY COSTS | TOUR & RECRE | ECOLOG COSTS | SUBSIST COSTS | LOST OIL | OTHER COSTS | TOTAL COSTS | COST/ BBL SPILL | COST/BBO HANDLED |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PLATFORM | 0.23 | 0.02 | 0.05 | 0.42 | 0.24 | 0.00 | 0.05 | 0.05 | 1.06 | 273.23 | 6.05 |
| PIPELINE | 0.18 | 0.02 | 0.05 | 0.39 | 0.23 | 0.00 | 0.05 | 0.04 | 0.96 | 264.47 | 10.98 |
| TANKERS | 0.09 | 0.01 | 0.02 | 0.25 | 0.10 | 0.00 | 0.02 | 0.02 | 0.52 | 312.00 | 5.97 |

### N. CALIF

| SOURCE | CLEAN & CONTROL | COMMERCIAL FISH DIRECT COSTS | COMMERCIAL FISH SECONDARY COSTS | TOUR & RECRE | ECOLOG COSTS | SUBSIST COSTS | LOST OIL | OTHER COSTS | TOTAL COSTS | COST/ BBL SPILL | COST/BBO HANDLED |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PLATFORM | 0.29 | 0.02 | 0.06 | 0.55 | 0.34 | 0.00 | 0.07 | 0.06 | 1.40 | 277.73 | 6.15 |
| PIPELINE | 0.23 | 0.02 | 0.06 | 0.51 | 0.32 | 0.00 | 0.06 | 0.06 | 1.27 | 268.97 | 11.16 |
| TANKERS | 0.12 | 0.01 | 0.03 | 0.33 | 0.15 | 0.00 | 0.03 | 0.03 | 0.69 | 316.50 | 6.05 |



ATTACHMENT B (CONT)

### ST. GEORGE

| SOURCE | CLEAN & CONTROL | COMMERCIAL FISH DIRECT COSTS | COMMERCIAL FISH SECONDARY COSTS | TOUR & RECRE | ECOLOG COSTS | SUBSIST COSTS | LOST OIL | OTHER COSTS | TOTAL COSTS | COST/ BBL SPILL | COST/BBO HANDLED |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PLATFORM | 0.12 | 0.00 | 0.00 | 0.02 | 0.16 | 0.09 | 0.03 | 0.02 | 0.44 | 186.59 | 4.13 |
| PIPELINE | 0.08 | 0.00 | 0.00 | 0.01 | 0.15 | 0.09 | 0.02 | 0.02 | 0.38 | 172.36 | 7.15 |
| TANKERS | 0.10 | 0.01 | 0.03 | 0.16 | 0.09 | 0.01 | 0.02 | 0.02 | 0.43 | 213.46 | 4.08 |

### MID-ATLAN

| SOURCE | CLEAN & CONTROL | COMMERCIAL FISH DIRECT COSTS | COMMERCIAL FISH SECONDARY COSTS | TOUR & RECRE | ECOLOG COSTS | SUBSIST COSTS | LOST OIL | OTHER COSTS | TOTAL COSTS | COST/ BBL SPILL | COST/BBO HANDLED |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PLATFORM | 0.05 | 0.06 | 0.05 | 0.03 | 0.05 | 0.00 | 0.01 | 0.01 | 0.26 | 207.45 | 4.59 |
| PIPELINE | 0.06 | 0.10 | 0.09 | 0.05 | 0.10 | 0.00 | 0.03 | 0.02 | 0.45 | 196.01 | 8.13 |
| TANKERS | 0.03 | 0.05 | 0.04 | 0.08 | 0.04 | 0.00 | 0.01 | 0.01 | 0.28 | 260.07 | 4.97 |

### N. ATLAN

| SOURCE | CLEAN & CONTROL | COMMERCIAL FISH DIRECT COSTS | COMMERCIAL FISH SECONDARY COSTS | TOUR & RECRE | ECOLOG COSTS | SUBSIST COSTS | LOST OIL | OTHER COSTS | TOTAL COSTS | COST/ BBL SPILL | COST/BBO HANDLED |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PLATFORM | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.06 | 162.61 | 3.60 |
| PIPELINE | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| TANKERS | 0.01 | 0.01 | 0.01 | 0.02 | 0.01 | 0.00 | 0.00 | 0.00 | 0.06 | 202.92 | 3.88 |

### ORE/WASH

| SOURCE | CLEAN & CONTROL | COMMERCIAL FISH DIRECT COSTS | COMMERCIAL FISH SECONDARY COSTS | TOUR & RECRE | ECOLOG COSTS | SUBSIST COSTS | LOST OIL | OTHER COSTS | TOTAL COSTS | COST/ BBL SPILL | COST/BBO HANDLED |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PLATFORM | 0.02 | 0.01 | 0.02 | 0.06 | 0.03 | 0.00 | 0.00 | 0.00 | 0.14 | 405.60 | 8.98 |
| PIPELINE | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| TANKERS | 0.02 | 0.01 | 0.02 | 0.06 | 0.02 | 0.00 | 0.00 | 0.00 | 0.13 | 430.11 | 8.22 |

### N. ALEUTIAN

| SOURCE | CLEAN & CONTROL | COMMERCIAL FISH DIRECT COSTS | COMMERCIAL FISH SECONDARY COSTS | TOUR & RECRE | ECOLOG COSTS | SUBSIST COSTS | LOST OIL | OTHER COSTS | TOTAL COSTS | COST/ BBL SPILL | COST/BBO HANDLED |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PLATFORM | 0.01 | 0.00 | 0.00 | 0.00 | 0.02 | 0.01 | 0.00 | 0.00 | 0.06 | 282.82 | 6.26 |
| PIPELINE | 0.02 | 0.01 | 0.01 | 0.01 | 0.04 | 0.02 | 0.00 | 0.00 | 0.10 | 270.20 | 11.21 |
| TANKERS | 0.01 | 0.00 | 0.00 | 0.02 | 0.01 | 0.00 | 0.00 | 0.00 | 0.04 | 246.01 | 4.70 |

ATTACHMENT B (CONT)

## GULFALASKA

| SOURCE | CLEAN & CONTROL | COMMERCIAL FISH DIRECT COSTS | COMMERCIAL FISH SECONDARY COSTS | TOUR & RECRE | ECOLOG COSTS | SUBSIST COSTS | LOST OIL | OTHER COSTS | TOTAL COSTS | COST/ BBL SPILL | COST/BBO HANDLED |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PLATFORM | 0.02 | 0.00 | 0.00 | 0.01 | 0.01 | 0.01 | 0.00 | 0.00 | 0.06 | 327.88 | 7.26 |
| PIPELINE | 0.03 | 0.01 | 0.01 | 0.03 | 0.02 | 0.01 | 0.00 | 0.00 | 0.11 | 324.06 | 13.45 |
| TANKERS | 0.01 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.04 | 238.65 | 4.56 |

## NORTON

| SOURCE | CLEAN & CONTROL | COMMERCIAL FISH DIRECT COSTS | COMMERCIAL FISH SECONDARY COSTS | TOUR & RECRE | ECOLOG COSTS | SUBSIST COSTS | LOST OIL | OTHER COSTS | TOTAL COSTS | COST/ BBL SPILL | COST/BBO HANDLED |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PLATFORM | 0.02 | 0.00 | 0.00 | 0.00 | 0.03 | 0.01 | 0.00 | 0.00 | 0.07 | 286.80 | 6.35 |
| PIPELINE | 0.03 | 0.00 | 0.00 | 0.01 | 0.05 | 0.03 | 0.01 | 0.01 | 0.13 | 268.06 | 11.12 |
| TANKERS | 0.02 | 0.00 | 0.00 | 0.02 | 0.02 | 0.00 | 0.00 | 0.00 | 0.07 | 305.09 | 5.83 |

## KODIAK

| SOURCE | CLEAN & CONTROL | COMMERCIAL FISH DIRECT COSTS | COMMERCIAL FISH SECONDARY COSTS | TOUR & RECRE | ECOLOG COSTS | SUBSIST COSTS | LOST OIL | OTHER COSTS | TOTAL COSTS | COST/ BBL SPILL | COST/BBO HANDLED |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PLATFORM | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| PIPELINE | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| TANKERS | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

## HOPE

| SOURCE | CLEAN & CONTROL | COMMERCIAL FISH DIRECT COSTS | COMMERCIAL FISH SECONDARY COSTS | TOUR & RECRE | ECOLOG COSTS | SUBSIST COSTS | LOST OIL | OTHER COSTS | TOTAL COSTS | COST/ BBL SPILL | COST/BBO HANDLED |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PLATFORM | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| PIPELINE | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| TANKERS | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

## SHUMAGIN

| SOURCE | CLEAN & CONTROL | COMMERCIAL FISH DIRECT COSTS | COMMERCIAL FISH SECONDARY COSTS | TOUR & RECRE | ECOLOG COSTS | SUBSIST COSTS | LOST OIL | OTHER COSTS | TOTAL COSTS | COST/ BBL SPILL | COST/BBO HANDLED |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PLATFORM | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| PIPELINE | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| TANKERS | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |



ATTACHMENT B (CONT)

## COOK INLET

| SOURCE | CLEAN & CONTROL | COMMERCIAL FISH DIRECT COSTS | COMMERCIAL FISH SECONDARY COSTS | TOUR & RECRE | ECOLOG COSTS | SUBSIST COSTS | LOST OIL | OTHER COSTS | TOTAL COSTS | COST/ BBL SPILL | COST/BBO HANDLED |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PLATFORM | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| PIPELINE | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| TANKERS | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

## STR OF FLORID

| SOURCE | CLEAN & CONTROL | COMMERCIAL FISH DIRECT COSTS | COMMERCIAL FISH SECONDARY COSTS | TOUR & RECRE | ECOLOG COSTS | SUBSIST COSTS | LOST OIL | OTHER COSTS | TOTAL COSTS | COST/ BBL SPILL | COST/BBO HANDLED |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PLATFORM | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 | 0.01 | 102.87 | 2.28 |
| PIPELINE | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 | 0.02 | 92.07 | 3.82 |
| TANKERS | 0.00 | 0.00 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 152.87 | 2.92 |

Attachment C
Present Discounted Value of Non-Spill Costs from Producing
All of the Leasable Resources Unleased as of mid 1987:
$29 per Barrel Starting Price
(in Millions of 1987 dollars).

| AREA | AIR POLLUTION COSTS | WETLANDS COSTS | COMM. FISH AREA PREM. & GEAR LOSS | INFRA-STRUCTURE COSTS | TOTAL NON-SPILL COSTS | NON-SPILL COSTS PER BBOE |
|---|---|---|---|---|---|---|
| CGOM | 7.0 | 6.7 | 2.4 | 0.0 | 16.0 | 3.9 |
| WESTGOM | 3.5 | 2.6 | 2.5 | 13.9 | 22.5 | 4.9 |
| S.CALIF | 3.8 | 0.6 | 1.0 | 0.0 | 5.3 | 6.5 |
| S.ATLAN | 0.7 | 0.6 | 0.7 | 1.9 | 3.9 | 5.1 |
| NAVARIN | 0.7 | 0.8 | 0.7 | 7.4 | 9.5 | 12.0 |
| EASTGOM | 0.4 | 1.1 | 0.2 | 1.3 | 2.9 | 6.2 |
| BEAUFRT | 0.2 | 1.1 | 0.0 | 0.0 | 1.4 | 4.4 |
| CHUKCHI | 0.3 | 0.0 | 0.0 | 0.0 | 0.3 | 0.7 |
| CEN.CALI | 0.3 | 0.5 | 0.2 | 1.2 | 2.2 | 9.7 |
| N.CALIF | 0.5 | 1.4 | 0.4 | 2.2 | 4.4 | 10.8 |
| ST.GEORG | 0.2 | 0.8 | 0.2 | 2.4 | 3.6 | 13.9 |
| MID-ATLA | 0.2 | 0.3 | 0.2 | 0.6 | 1.3 | 5.7 |
| N.ATLAN | 0.1 | 0.4 | 0.0 | 0.2 | 0.7 | 9.7 |
| ORE/WASH | 0.1 | 0.0 | 0.1 | 0.2 | 0.3 | 4.6 |
| N.ALEUTI | 0.0 | 0.0 | 0.0 | 0.2 | 0.2 | 10.9 |
| GULFALAS | 0.0 | 0.0 | 0.0 | 0.3 | 0.3 | 10.7 |
| NORTON | 0.0 | 0.0 | 0.0 | 0.4 | 0.4 | 20.0 |
| KODIAK | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| HOPE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SHUMAGIN | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| COOK INL | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| STR OF F | 0.0 | 0.3 | 0.0 | 0.0 | 0.3 | 31.2 |



ATTACHMENT D : Summary of Information by Area
For $29 Starting Oil Price

CGOM
Resources (BBOE)
Oil - 1.67
Gas - 2.44
Total - 4.11

Oil Spills

| | Number of Large Spills | Amount Spilled (Large and Small) |
|---|---|---|
| Coming Ashore - | 3.31 | 76851.73 |
| Remaining at Sea - | 0.94 | 22115.88 |
| Total - | 4.25 | 98967.61 |

| | | |
|---|---|---|
| TOTAL OIL SPILL COSTS - | $ | 34.70 |
| NON-SPILL COSTS - | $ | 16.00 |
| - OIL SPILLS BACKED OUT - | -$ | 8.42 |
| Total Net Social Cost - | $ | 42.27 Million |
| Net Social Cost per BBOE - | $ | 10.29 Million |
| Total Net Cost Borne by Area Residents From Production in ALL Areas | $ | 27.70 Million |

WESTGOM
Resources (BBOE)
Oil - 1.32
Gas - 3.31
Total - 4.63

Oil Spills

| | Number of Large Spills | Amount Spilled (Large and Small) |
|---|---|---|
| Coming Ashore - | 2.46 | 56306.56 |
| Remaining at Sea - | 0.87 | 20312.29 |
| Total - | 3.33 | 76618.84 |

| | | |
|---|---|---|
| TOTAL OIL SPILL COSTS - | $ | 19.24 |
| NON-SPILL COSTS - | $ | 22.48 |
| - OIL SPILLS BACKED OUT - | -$ | 5.90 |
| Total Net Social Cost - | $ | 35.82 Million |
| Net Social Cost per BBOE - | $ | 7.74 Million |
| Total Net Cost Borne by Area Residents From Production in ALL Areas | $ | 21.84 Million |

ATTACHMENT D: Summary of Information by Area (CONT)

S.CALIF
Resources (BBOE)
Oil - 0.65
Gas - 0.17
Total - 0.82

Oil Spills

| | Number of Large Spills | Amount Spilled (Large and Small) |
|---|---|---|
| Coming Ashore - | 1.08 | 22112.53 |
| Remaining at Sea - | 0.85 | 18752.51 |
| Total - | 1.92 | 40865.04 |

| | | |
|---|---|---|
| TOTAL OIL SPILL COSTS - | $ | 11.33 |
| NON-SPILL COSTS - | $ | 5.33 |
| - OIL SPILLS BACKED OUT - | -$ | 4.31 |
| Total Net Social Cost - | $ | 12.34 Million |
| Net Social Cost per BBOE - | $ | 15.05 Million |
| Total Net Cost Borne by Area Residents From Production in ALL Areas | $ | 15.72 Million |

S.ATLAN
Resources (BBOE)
Oil - 0.15
Gas - 0.62
Total - 0.77

Oil Spills

| | Number of Large Spills | Amount Spilled (Large and Small) |
|---|---|---|
| Coming Ashore - | 0.08 | 1318.82 |
| Remaining at Sea - | 0.50 | 10970.87 |
| Total - | 0.58 | 12289.70 |

| | | |
|---|---|---|
| TOTAL OIL SPILL COSTS - | $ | 1.90 |
| NON-SPILL COSTS - | $ | 3.93 |
| - OIL SPILLS BACKED OUT - | -$ | 0.81 |
| Total Net Social Cost - | $ | 5.02 Million |
| Net Social Cost per BBOE - | $ | 6.52 Million |
| Total Net Cost Borne by Area Residents From Production in ALL Areas | $ | 4.57 Million |



ATTACHMENT D: Summary of Information by Area (CONT)

NAVARIN
Resources (BBOE)
Oil - 0.65
Gas - 0.14
Total - 0.79

Oil Spills

| | Number of Large Spills | Amount Spilled (Large and Small) |
|---|---|---|
| Coming Ashore - | 0.64 | 11849.59 |
| Remaining at Sea - | 1.43 | 34892.95 |
| Total - | 2.06 | 46742.54 |

| | | |
|---|---|---|
| TOTAL OIL SPILL COSTS - | $ | 9.44 |
| NON-SPILL COSTS - | $ | 9.49 |
| - OIL SPILLS BACKED OUT - | -$ | 3.23 |
| Total Net Social Cost - | $ | 15.70 Million |
| Net Social Cost per BBOE - | $ | 19.87 Million |
| Total Net Cost Borne by Area Residents From Production in ALL Areas | $ | 13.87 Million |

EASTGOM
Resources (BBOE)
Oil - 0.24
Gas - 0.23
Total - 0.47

Oil Spills

| | Number of Large Spills | Amount Spilled (Large and Small) |
|---|---|---|
| Coming Ashore - | 0.46 | 9503.69 |
| Remaining at Sea - | 0.48 | 10615.24 |
| Total - | 0.95 | 20118.94 |

| | | |
|---|---|---|
| TOTAL OIL SPILL COSTS - | $ | 3.77 |
| NON-SPILL COSTS - | $ | 2.91 |
| - OIL SPILLS BACKED OUT - | -$ | 1.10 |
| Total Net Social Cost - | $ | 5.58 Million |
| Net Social Cost per BBOE - | $ | 11.87 Million |
| Total Net Cost Borne by Area Residents From Production in ALL Areas | $ | 6.09 Million |

ATTACHMENT D: Summary of Information by Area (CONT)

BEAUFRT
Resources (BBOE)
Oil - 0.31
Gas - 0.00
Total - 0.31

Oil Spills

| | Number of Large Spills | Amount Spilled (Large and Small) |
|---|---|---|
| Coming Ashore - | 0.25 | 5469.08 |
| Remaining at Sea - | 0.62 | 15171.09 |
| Total - | 0.87 | 20640.17 |

| | | |
|---|---|---|
| TOTAL OIL SPILL COSTS - | $ | 4.49 |
| NON-SPILL COSTS - | $ | 1.38 |
| - OIL SPILLS BACKED OUT - | -$ | 1.44 |
| Total Net Social Cost - | $ | 4.43 Million |
| Net Social Cost per BBOE - | $ | 14.28 Million |
| Total Net Cost Borne by Area Residents From Production in ALL Areas | $ | 3.59 Million |

CHUKCHI
Resources (BBOE)
Oil - 0.40
Gas - 0.00
Total - 0.40

Oil Spills

| | Number of Large Spills | Amount Spilled (Large and Small) |
|---|---|---|
| Coming Ashore - | 0.31 | 6904.14 |
| Remaining at Sea - | 0.81 | 19728.34 |
| Total - | 1.12 | 26632.48 |

| | | |
|---|---|---|
| TOTAL OIL SPILL COSTS - | $ | 4.53 |
| NON-SPILL COSTS - | $ | 0.27 |
| - OIL SPILLS BACKED OUT - | -$ | 1.59 |
| Total Net Social Cost - | $ | 3.21 Million |
| Net Social Cost per BBOE - | $ | 8.01 Million |
| Total Net Cost Borne by Area Residents From Production in ALL Areas | $ | 2.50 Million |



ATTACHMENT D: Summary of Information by Area (CONT)

CEN.CALIF
Resources (BBOE)
Oil - 0.17
Gas - 0.06
Total - 0.23

Oil Spills

| | Number of Large Spills | Amount Spilled (Large and Small) |
|---|---|---|
| Coming Ashore - | 0.37 | 4581.51 |
| Remaining at Sea - | 0.29 | 4914.77 |
| Total - | 0.67 | 9496.28 |

| | | |
|---|---|---|
| TOTAL OIL SPILL COSTS - | $ | 2.54 |
| NON-SPILL COSTS - | $ | 2.24 |
| - OIL SPILLS BACKED OUT - | -$ | 1.14 |
| Total Net Social Cost - | $ | 3.64 Million |
| Net Social Cost per BBOE - | $ | 15.82 Million |
| Total Net Cost Borne by Area Residents From Production in ALL Areas | $ | 5.50 Million |

N.CALIF
Resources (BBOE)
Oil - 0.23
Gas - 0.18
Total - 0.41

Oil Spills

| | Number of Large Spills | Amount Spilled (Large and Small) |
|---|---|---|
| Coming Ashore - | 0.34 | 5767.48 |
| Remaining at Sea - | 0.36 | 6383.35 |
| Total - | 0.70 | 12150.84 |

| | | |
|---|---|---|
| TOTAL OIL SPILL COSTS - | $ | 3.36 |
| NON-SPILL COSTS - | $ | 4.44 |
| - OIL SPILLS BACKED OUT - | -$ | 1.49 |
| Total Net Social Cost - | $ | 6.31 Million |
| Net Social Cost per BBOE - | $ | 15.39 Million |
| Total Net Cost Borne by Area Residents From Production in ALL Areas | $ | 7.41 Million |

ATTACHMENT D: Summary of Information by Area (CONT)

ST. GEORGE
Resources (BBOE)
Oil - 0.11
Gas - 0.15
Total - 0.26

Oil Spills

| | Number of Large Spills | Amount Spilled (Large and Small) |
|---|---|---|
| Coming Ashore - | 0.05 | 986.09 |
| Remaining at Sea - | 0.17 | 3998.60 |
| Total - | 0.22 | 4984.69 |

| | | |
|---|---|---|
| TOTAL OIL SPILL COSTS - | $ | 1.26 |
| NON-SPILL COSTS - | $ | 3.64 |
| - OIL SPILLS BACKED OUT - | -$ | 0.54 |
| Total Net Social Cost - | $ | 4.36 Million |
| Net Social Cost per BBOE - | $ | 16.76 Million |
| Total Net Cost Borne by Area Residents From Production in ALL Areas | $ | 4.18 Million |

MID-ATLAN
Resources (BBOE)
Oil - 0.06
Gas - 0.17
Total - 0.23

Oil Spills

| | Number of Large Spills | Amount Spilled (Large and Small) |
|---|---|---|
| Coming Ashore - | 0.04 | 782.36 |
| Remaining at Sea - | 0.17 | 3832.02 |
| Total - | 0.22 | 4614.39 |

| | | |
|---|---|---|
| TOTAL OIL SPILL COSTS - | $ | 0.99 |
| NON-SPILL COSTS - | $ | 1.31 |
| - OIL SPILLS BACKED OUT - | -$ | 0.31 |
| Total Net Social Cost - | $ | 1.98 Million |
| Net Social Cost per BBOE - | $ | 8.62 Million |
| Total Net Cost Borne by Area Residents From Production in ALL Areas | $ | -0.24 Million |



ATTACHMENT D: Summary of Information by Area (CONT)

N. ATLAN
Resources (BBOE)
Oil - 0.02
Gas - 0.05
Total - 0.07

Oil Spills

| | Number of Large Spills | Amount Spilled (Large and Small) |
|---|---|---|
| Coming Ashore - | 0.01 | 150.73 |
| Remaining at Sea - | 0.03 | 509.42 |
| Total - | 0.04 | 660.14 |

| | | |
|---|---|---|
| TOTAL OIL SPILL COSTS - | $ | 0.12 |
| NON-SPILL COSTS - | $ | 0.69 |
| - OIL SPILLS BACKED OUT - | -$ | 0.07 |
| Total Net Social Cost - | $ | 0.74 Million |
| Net Social Cost per BBOE - | $ | 10.62 Million |
| Total Net Cost Borne by Area Residents From Production in ALL Areas | $ | 0.61 Million |

ORE/WASH
Resources (BBOE)
Oil - 0.02
Gas - 0.04
Total - 0.06

Oil Spills

| | Number of Large Spills | Amount Spilled (Large and Small) |
|---|---|---|
| Coming Ashore - | 0.22 | 518.73 |
| Remaining at Sea - | 0.09 | 221.02 |
| Total - | 0.31 | 739.76 |

| | | |
|---|---|---|
| TOTAL OIL SPILL COSTS - | $ | 0.28 |
| NON-SPILL COSTS - | $ | 0.28 |
| - OIL SPILLS BACKED OUT - | -$ | 0.10 |
| Total Net Social Cost - | $ | 0.45 Million |
| Net Social Cost per BBOE - | $ | 7.55 Million |
| Total Net Cost Borne by Area Residents From Production in ALL Areas | $ | 1.16 Million |

ATTACHMENT D: Summary of Information by Area (CONT)

N. ALEUTIAN

Resources (BBOE)

Oil - 0.01
Gas - 0.01
Total - 0.02

Oil Spills

| | Number of Large Spills | Amount Spilled (Large and Small) |
|---|---|---|
| Coming Ashore - | 0.01 | 219.59 |
| Remaining at Sea - | 0.02 | 372.18 |
| Total - | 0.02 | 591.77 |

| | | |
|---|---|---|
| TOTAL OIL SPILL COSTS - | $ | 0.20 |
| NON-SPILL COSTS - | $ | 0.23 |
| - OIL SPILLS BACKED OUT - | -$ | 0.05 |
| Total Net Social Cost - | $ | 0.38 Million |
| Net Social Cost per BBOE - | $ | 18.76 Million |
| Total Net Cost Borne by Area Residents From Production in ALL Areas | $ | 0.33 Million |

GULFALASKA

Resources (BBOE)

Oil - 0.01
Gas - 0.02
Total - 0.03

Oil Spills

| | Number of Large Spills | Amount Spilled (Large and Small) |
|---|---|---|
| Coming Ashore - | 0.02 | 474.19 |
| Remaining at Sea - | 0.00 | 78.90 |
| Total - | 0.02 | 553.09 |

| | | |
|---|---|---|
| TOTAL OIL SPILL COSTS - | $ | 0.20 |
| NON-SPILL COSTS - | $ | 0.33 |
| - OIL SPILLS BACKED OUT - | -$ | 0.04 |
| Total Net Social Cost - | $ | 0.49 Million |
| Net Social Cost per BBOE - | $ | 16.36 Million |
| Total Net Cost Borne by Area Residents From Production in ALL Areas | $ | 0.69 Million |





NORTON

Resources (BBOE)

Oil - 0.01
Gas - 0.01
Total - 0.02

Oil Spills

| | Number of Large Spills | Amount Spilled (Large and Small) |
|---|---|---|
| Coming Ashore - | 0.01 | 217.62 |
| Remaining at Sea - | 0.02 | 552.02 |
| Total - | 0.03 | 769.64 |

| | | |
|---|---|---|
| TOTAL OIL SPILL COSTS - | $ | 0.27 |
| NON-SPILL COSTS - | $ | 0.42 |
| - OIL SPILLS BACKED OUT - | -$ | 0.09 |
| Total Net Social Cost - | $ | 0.60 Million |
| Net Social Cost per BBOE - | $ | 30.06 Million |
| Total Net Cost Borne by Area Residents From Production in ALL Areas | $ | 0.54 Million |

KODIAK

Resources (BBOE)

Oil - 0.00
Gas - 0.00
Total - 0.00

Oil Spills

| | Number of Large Spills | Amount Spilled (Large and Small) |
|---|---|---|
| Coming Ashore - | 0.00 | 0.00 |
| Remaining at Sea - | 0.00 | 0.00 |
| Total - | 0.00 | 0.00 |

| | | |
|---|---|---|
| TOTAL OIL SPILL COSTS - | $ | 0.00 |
| NON-SPILL COSTS - | $ | 0.00 |
| - OIL SPILLS BACKED OUT - | -$ | 0.00 |
| Total Net Social Cost - | $ | 0.00 Million |
| Net Social Cost per BBOE - | $ | 0.00 Million |
| Total Net Cost Borne by Area Residents From Production in ALL Areas | $ | 0.00 Million |

ATTACHMENT D: Summary of Information by Area (CONT)

HOPE
Resources (BBOE)
Oil - 0.00
Gas - 0.00
Total - 0.00

Oil Spills

| | Number of Large Spills | Amount Spilled (Large and Small) |
|---|---|---|
| Coming Ashore - | 0.00 | 0.00 |
| Remaining at Sea - | 0.00 | 0.00 |
| Total - | 0.00 | 0.00 |

| | | | |
|---|---|---|---|
| TOTAL OIL SPILL COSTS - | $ | 0.00 | |
| NON-SPILL COSTS - | $ | 0.00 | |
| - OIL SPILLS BACKED OUT - | -$ | 0.00 | |
| Total Net Social Cost - | $ | 0.00 | Million |
| Net Social Cost per BBOE - | $ | 0.00 | Million |
| Total Net Cost Borne by Area Residents From Production in ALL Areas | $ | 0.00 | Million |

SHUMAGIN
Resources (BBOE)
Oil - 0.00
Gas - 0.00
Total - 0.00

Oil Spills

| | Number of Large Spills | Amount Spilled (Large and Small) |
|---|---|---|
| Coming Ashore - | 0.00 | 0.00 |
| Remaining at Sea - | 0.00 | 0.00 |
| Total - | 0.00 | 0.00 |

| | | | |
|---|---|---|---|
| TOTAL OIL SPILL COSTS - | $ | 0.00 | |
| NON-SPILL COSTS - | $ | 0.00 | |
| - OIL SPILLS BACKED OUT - | $ | 0.00 | |
| Total Net Social Cost - | $ | 0.00 | Million |
| Net Social Cost per BBOE - | $ | 0.00 | Million |
| Total Net Cost Borne by Area Residents From Production in ALL Areas | $ | 0.10 | Million |



ATTACHMENT D: Summary of Information by Area (CONT)

COOK INLET
Resources (BBOE)
Oil - 0.00
Gas - 0.00
Total - 0.00

Oil Spills

| | Number of Large Spills | Amount Spilled (Large and Small) |
|---|---|---|
| Coming Ashore - | 0.00 | 0.00 |
| Remaining at Sea - | 0.00 | 0.00 |
| Total - | 0.00 | 0.00 |

| | | | |
|---|---|---|---|
| TOTAL OIL SPILL COSTS - | $ | 0.00 | |
| NON-SPILL COSTS - | $ | 0.00 | |
| - OIL SPILLS BACKED OUT - | -$ | 0.00 | |
| Total Net Social Cost - | $ | 0.00 | Million |
| Net Social Cost per BBOE - | $ | 0.00 | Million |
| Total Net Cost Borne by Area Residents From Production in ALL Areas | $ | 0.00 | Million |

STR OF FLOR
Resources (BBOE)
Oil - 0.00
Gas - 0.00
Total - 0.01

Oil Spills

| | Number of Large Spills | Amount Spilled (Large and Small) |
|---|---|---|
| Coming Ashore - | 0.00 | 29.41 |
| Remaining at Sea - | 0.02 | 384.38 |
| Total - | 0.02 | 413.79 |

| | | | |
|---|---|---|---|
| TOTAL OIL SPILL COSTS - | $ | 0.05 | |
| NON-SPILL COSTS - | $ | 0.34 | |
| - OIL SPILLS BACKED OUT - | -$ | 0.02 | |
| Total Net Social Cost - | $ | 0.36 | Million |
| Net Social Cost per BBOE - | $ | 36.45 | Million |
| Total Net Cost Borne by Area Residents From Production in ALL Areas | $ | 0.35 | Million |

ATTACHMENT E

## Sensitivity Analysis of Social Cost Estimates for Each OCS Planning Area Using the Procedure Developed for Type A Natural Resource Damage Assessments Under CERCLA

### E.1 Background and Introduction

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA) requires the U.S. Department of the Interior to develop national regulations for assessing damages to natural resources from spills of oil and hazardous substances covered under the Act and the Clean Water Act, as amended. In response to this legislation, use of the Natural Resource Damage Assessment Model for Coastal and Marine Environments (NRDAM/CME) has been developed as a simplified procedure for assessing damages from injury to natural resources resulting from small spills of oil and hazardous substances in the coastal and marine environments. Following a brief background description of CERCLA, this attachment outlines the NRDAM/CME and then examines how the estimates of social cost developed earlier in this Appendix would change when the methodology employed in the NRDAM/CME is used to measure those categories of costs included in this model.

Under CERCLA and the Clean Water Act, as amended, polluters are required to compensate public and private parties for responding to and cleaning up a discharge of oil not permitted under these laws. In addition, the affected State or the Federal government, in their role as trustee, could also assert a claim for compensation for injury to, destruction of, or loss of natural resources (henceforth called injury to natural resource) and for the reasonable cost of conducting a natural resource damage assessment.

CERCLA (Sec. 301(c)(1)) requires the Federal government to develop two types of regulations for assessing damages from injury to natural resource:

(A) standard procedures for simplified assessment requiring minimal field observation, including establishing measures of damages based onunits of discharge or release or units of affected area, and

(B) alternative protocols for conducting assessments in individual cases to determine the type and extent of short- and long-term injury, destruction or loss. (Section 301(c)(2))

The Act specifies that type A and type B regulations:

.....shall identify the best available procedures to determine such damages, including both direct and indirect injury, destruction, or loss and shall take into consideration factors including, but not limited to, replacement value, lost use value, and ability of the ecosystem to recover. (Section 301(c)(2)).



Final rules for carrying out type A natural resource damage assessments have been published by the U.S. Department of the Interior (43 CFR Part 11, March 20, 1987, 9042-9100). The rules provide a new procedure for measuring short- and long-term damages from injury to a variety of natural resources in coastal and marine environments. The rules use a computer program to carry out the necessary computations required to assess damages resulting from a particular incident, given limited information supplied by the user. The assessment model is refered to as the Natural Resource Damage Assessment Model for Coastal and Marine Environments (NRDAM/CME) and was developed by Economic Analysis, Inc. of Wakefield, Rhode Island and Applied Science Associates, Inc. of Narragansett, Rhode Island.

This attachment uses the new NRDAM/CME methodology to provide a sensitivity analysis of the potential social costs of developing, producing and transporting all of the leaseable oil and natural gas resources estimated to be unleased as of mid-1987 for each of the OCS planning areas. The analysis is intended to provide a perspective on how the social cost estimates presented in the body of Appendix G would change when the new methodology provided by CERCLA is employed. However, the analysis presented here cannot be viewed as a substitute for the analysis given in the previous sections of Appendix G. First, the geographic areas used in the NRDAM/CME model (described below) differ considerably from, and are far larger than, most OCS planning areas. Second, the categories of natural resource damages compensable under CERCLA (also described below) are not the same as, and in some respects are much narrower than, the social costs considered in Appendix G. For these reasons, the sensitivity analysis presented in this attachment cannot be viewed as a substitute for the results presented earlier in Appendix G.

The remainder of this attachment is organized as follows. First, the NRDAM/CME model and the catagories of natural resource damages considered within the model are described briefly. Second, the methodology used to apply the model to measure some of the potential social costs of OCS oil and gas development, production and transportation is explained. Third, the results of the sensitivity analysis are presented; and finally, a summary and concluding comments are provided.

### E.2 Brief Description of NRDAM/CME Model

#### E.2.1 Overview of the NRDAM/CME Model

The NRDAM/CME model is an integrated, interdisciplinary model containing physical fates, biological effects and economic damages submodels. The general logic of the approach is illustrated in Figure E.I. A brief, non-technical discussion of the model follows. Readers interested in a more detailed presentation of the model and the data used to implement the model are refered to the original technical document (Economic Analysis, Inc. and Applied Science Associates, 1986).

The consequences of a given spill could vary greatly, depending upon the amount and characteristics of the substance spilled, such as its physical, chemical and toxicological properties, and the characteristics of the environment in which the spill occurs, such as the location and season of the incident, the water depth, currents, temperature and the

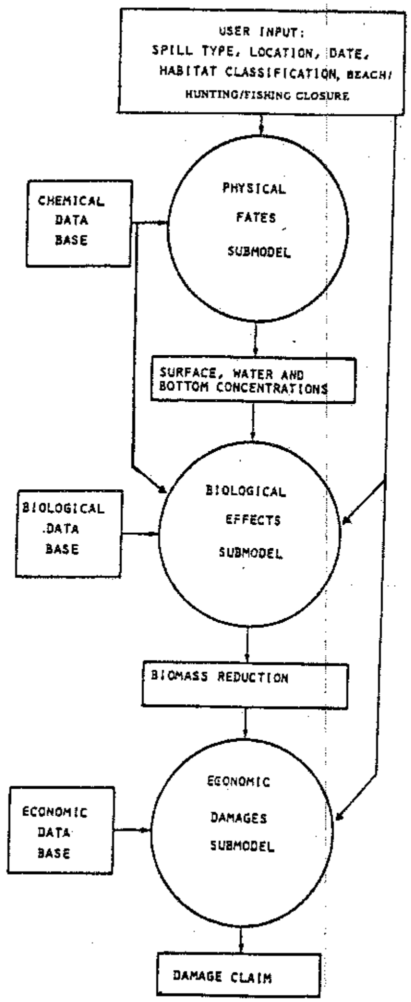


Figure E.1 Overview of type A natural resources damage assessment model for coastal and marine environments.



specific natural resources in the affected area and their vulnerability to injury from spilled oil. The measurement of damages from a particular incident requires that linkages be established, in sequence, from an incident to its effect on ambient conditions, to biological and physical injuries and, ultimately, to the measure of damages which is quantified in monetary terms.

The physical fates submodel has a chemical data base which contains information on several hundred oil and chemical substances obtained from established data bases. The physical, chemical and toxicological information contained in this data base includes such parameters as density, solubility, vapor pressure, degredation rates in sea water and in sediments, adsorbed/dissolved partition coefficient (Koc), and toxicological information for phytoplankton, zooplankton, ichthyoplankton, adult fish, and benthos.

Given the amount and the physical/chemical parameters of the substance spilled, the fates submodel simulates its spreading, mixing, and degredation in four layers of the environment: the surface, upper water column, lower water column and bottom sediments. In addition, the submodel accounts for the amount of the pollutant lost to the atmosphere through evaporation, where appropriate. A mass balance calculation ensures that the sum of the mass of the pollutant in all environmental compartments at each point in time equals the mass spilled. The model also allows the user to specify the amount cleaned up and the time of removal from the environment; if any cleanup occurs, damages are measured taking into account the amount removed and the timing of the cleanup.

To simulate the fate of an oil spill, the physical fates submodel incorporates information on specific coastal and marine environmental parameters. These parameters include the depth of the upper and lower water column, the mean and tidal currents, wind speed and direction, as well as air temperature and distance to shorelines, or boundaries of concern, in each direction. In a particular application, these parameters are to be set by the user. The output of the physical fates simulation of a spill is concentration of the pollutant, over time, in various cells for each of the four layers. This information is passed to the biological effects submodel.

The biological effects submodel calculates injury to various biota in the coastal and marine environments. To define biological resource in contact with a spill, the biological submodel employs a substantial data base on biological abundance of various categories of finfish, shellfish, fur seals and birds (divided into shorebirds, waterfowl and seabirds). The data base specifies the abundance of species groups in each of ten provinces/ecosystem types defined in Cowardin et al. (1979) for the coastal marine environments of the United States and its territories (Fig. E.2). Abundance of the species groups within a province varies by season, bottom type, marine vs. estuarine, and tidal vs. subtidal environments. In total, 91 different ecosystem categories are considered in the biological effects submodel.

The effect of a spill on marine organisms depends on the concentration of the substance in the physical environment where the organisms live. Above a threshhold level, the impact increases with concentration, using the results of quality controlled, standard laboratory toxicity tests. The biological effects submodel calculates

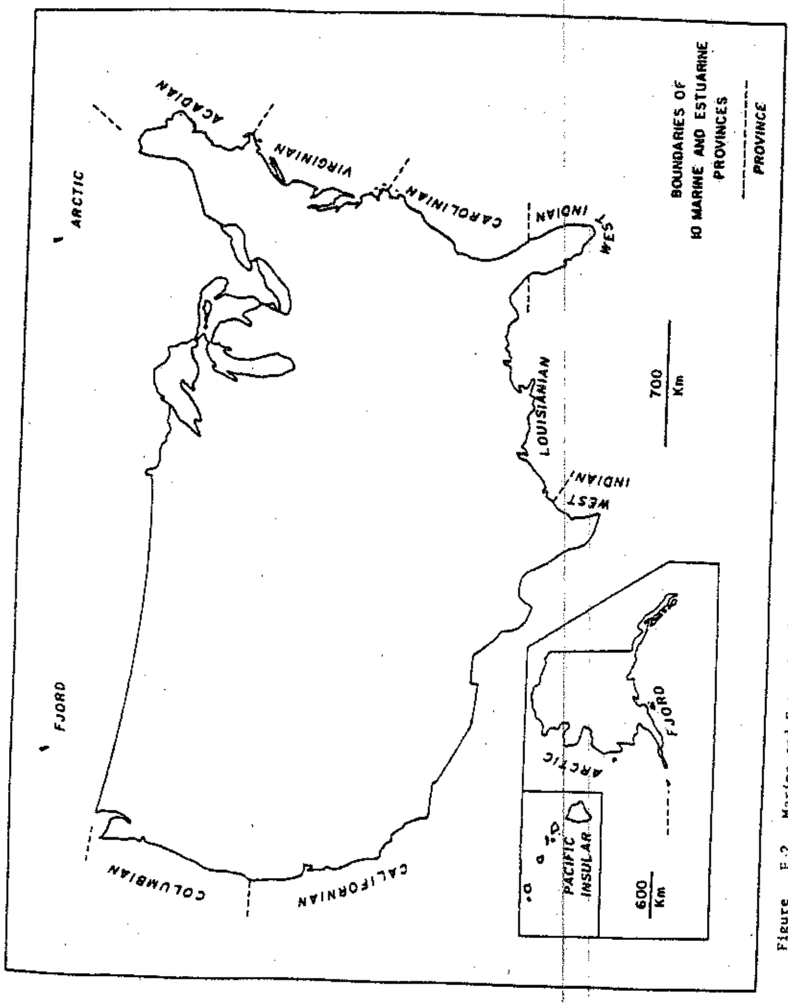


Figure E.2. Marine and Estuarine Provinces.
Sources: Adapted from L.M. Cowardin et al., 1979. "Classification of Wetlands and Deepwater Habitats of the United States," FWS/OBS-79,31.



direct loss of adult and juveniles for waterfowl, shorebirds and shorebirds, loss of fur seals and losses for nine fish and shellfish species categories and loss of larvae for each of these categories. In addition, a simple food model is used to trace indirect losses through the food chain.

Biological injury quantified in the submodel includes 1) short-term injury (e.g., death) and (2) long-term injuries which occur over time (e.g., lost recruitment). Three categories of short-term biological effects are considered. First, surface oil slicks may be encountered by birds and fur seals. Second, the dissolved portion of a spill can kill various fish species. Finally, spilled material can sink to the bottom killing bottom fish species, although in deep water acute effects of oil on bottom fish should be negligible. Long-term losses due to the effects of acute toxicity on the biomass via lost larvae and juveniles also are taken into account using a dynamic, cohort model of the biological system.

### E.2.2 Definition and Scope of Damages Considered in the Model

Damages to natural resources are measured by the difference in their *in situ* use value in the post-incident compared with the pre-incident situation, where *in situ* value is the value of the natural resources in place. Damages are measured from the time of the incident through the period of resource recovery. To the extent that the response to an incident mitigates damages through the cleanup of some of the discharged oil, the model can be used to measure damages net of the amount of the spilled oil cleaned up. However, for the purposes of this sensitivity analysis, it is assumed that no spilled oil is cleaned up. This assumption is made in keeping with the conservative, i.e., high-cost approach used elsewhere in this appendix of overstating costs whenever uncertainty exists concerning a cost estimate or an outcome.

It is important to point out that under CERCLA only Federal and State governments, in their role as trustees, can assert a claim for damages to natural resources under their jurisdiction; private parties cannot claim damages under this Act. Therefore, for example, economic losses suffered by shoreline hotel and restautant owners and employees, or seafood processing plants, resulting from an oil spill could not be recovered under CERCLA (although such losses may be compensable under the OCSLA).

The specific damages considered in the NRDAM/CME do not coincide exactly with those considered in the body of appendix G. The NRDAM/CME includes short- and long-term losses to commercial and recreational fisheries, consumptive (hunting) and non-consumptive (e.g., birdwatching) losses from destruction of seabirds, shorebirds and waterfowl, losses to fur seals, and losses from closure of public beaches. In addition, a simple food-chain model measures damages which result when a spill reduces the productivity of the food chain, thereby eventually causing losses of commercial and recreational fisheries, shorebirds, waterfowl and sebirds and fur seals. Thus, the NRDAM/CME includes some damage categories not considered in the social cost estimates developed in previous sections of this appendix (e.g., birds, fur seals) but excludes a variety of other potential costs (e.g., losses to the tourism industry, secondary (multiplier) effects and all non-spill costs). The catagories of damages considered and the general relationships among the physical fates and biological effects submodels and the economic damages submodel are indicated in Fig. E.3.

In carrying out this sensitivity analysis, the NRDAM/CME is used to measure only those damages which can be quantified using this approach. However, in this attachment, public beach losses are <u>not</u> measured using the NRDAM/CME. This category of potential damages is specifically not considered because in order to measure these damages using the NRDAM/CME, one must specify the length of beach closed, the type of <u>public</u> beach closed (i.e., national or other public beaches) and the duration of the closure. In the context of carrying out a social cost analysis for the Five Year OCS Oil and Gas Leasing Program such a degree of specificity is infeasible, given the high degree of uncertainty associated with estimating the possible number, size, fate and seasonality of oil spills which could occur over the broad geographic area encompassed by an OCS planning area.

## E.3 Application of the CERCLA NRDAM/CME Model

### E.3.1 Introduction

In order to apply the CERCLA NRDAM/CME model to possible oil spills which could result from the leasing of OCS oil and gas resources, it is necessary to address several issues. First, because the geographic areas used in the CERCLA analysis differ from the OCS planning areas, it is necessary to indicate how the two definitions of geographic areas are to be reconciled for the purposes of the sensitivity analysis. Second, the environmental parameters (e.g., the water depth) to be used to characterize possible oil spills in each OCS planning area must be specified. Third, while the previous sections of this appendix assume constant marginal and average costs per barrel spilled, damages measured with the NRDAM/CME framework increase with respect to the amount of oil spilled, and may do so at an increasing, decreasing or constant rate. Hence, to apply the NRDAM/CME it is necessary to estimate damages as a function of the distribution on spill sizes. Each of these issues is addressed in turn.

### E.3.2 Assumptions Used to Reconcile CERCLA Provinces and OCS Planning Areas

The NRDAM/CME divides the country into ten provinces or ecosystem types, based on the hierarcial system established in Cowardin et al. for the United States. The provinces range from an Arctic province for polar regions to a West Indies province for tropical-type environments. As indicated in Fig. E.2, the NRDAM/CME provinces in a number of instances do not conform closely with those of the OCS planning areas. For example, the Louisiana province encompasses all or part of three OCS planning areas: the Western, Central and Eastern Gulf of Mexico areas. Also, there are fourteen Alaskan OCS planning areas, but the NRDAM/CME model only has two provinces in Alaska, the Fjord province which includes the southeastern section of the State and the Artic province which covers all geographioc areas north of the Aleutian chain (see Maps 1 and 2 in the Detailed Decision Documents, Attachment 3).

For the purposes of this sensitivity analysis, all OCS planning areas are placed within the CERCLA province which most closely corresponds to the OCS area concerned. Table E.1 summarizes the



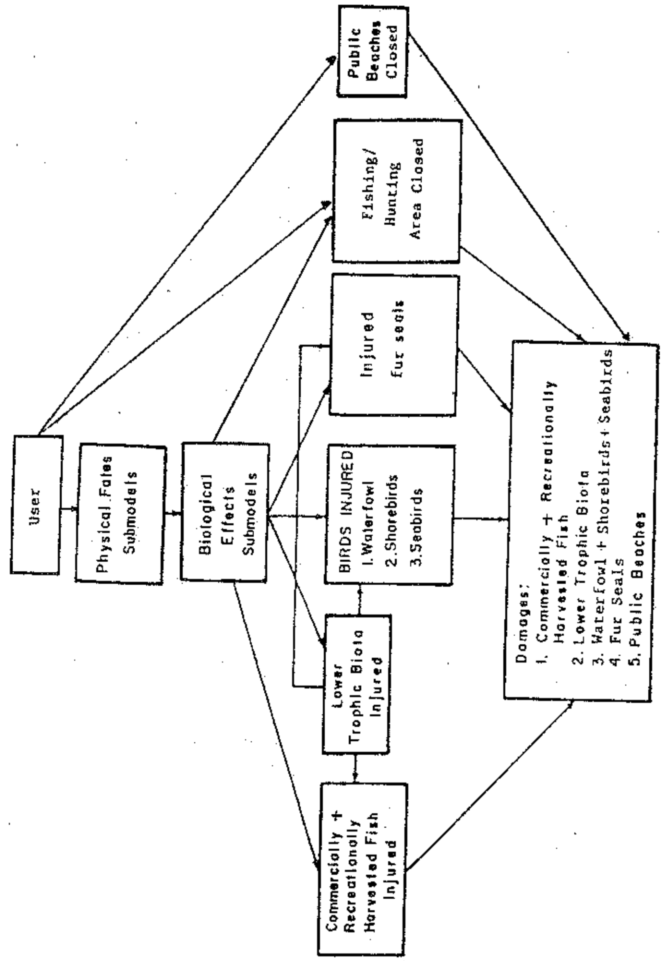


Figure E.3 Simplified representation of the natural resource damage assessment process and damage categories considered in the economic damages submodel in the NRDAM/CME.

correspondence between the two sets of geographic areas used in the analysis which follows.

### E.3.3 Environmental Parameters Used to Characterize Each OCS Planning Area

As describes above, several environmental parameters are important determinants of how spilled oil disperses and degrades in the environment and the resulting biological injuries and economic damages. Hence, it is important to indicate how the environmental parameters are established for this sensitivity analysis. Considerable uncertainty exists concerning the precise location of leaseable hydrocarbon resources within an OCS planning area, whether or not a spill will occur and its timing and location. For this reason in this sensitivity analysis a number of simplifying assumptions are used to characterize hypothetical oil spills in OCS planning areas. These assumptions are explained below.

First, all crude oil spills in the Alaskan and West Coast OCS planning areas are assumed to involve spills of heavy oil, while spills in the Gulf of Mexico and Atlantic OCS planning areas are assumed to involve medium weight oil. Second, all oil spills are assumed to occur in relatively shallow water--a 10 meter upper water column and 20 meter lower water column are assumed for all cases (about 90 feet of water depth, in total). Third, in order to examine the potential maximum damages from hypothetical oil spills, it is assumed that all of the spilled oil strikes the shoreline (except for spills in the Navarin Basin which are so distant from shore that they are assumed to remain at sea). Thus, for the purposes of overstating shoreline damages, all of the oil spilled at sea is assumed to come ashore; that is, in the NRDAM/CME operationally the amount oil coming ashore is regarded as a "new" spill equal in size to the original spill. In short, in addition to subtidal losses which result from offshore spills, intertidal losses also are assumed to occur when all of the oil spilled reaches land.

The shoreline type (e.g., sandy beach vs. rocky shore) can be an important determinant of the composition and magnitude of biological injuries and hence damages. To account for this factor, the type of shoreline likely to be contacted by OCS-related oil spills is specified in the NRDAM/CME, using the approach described below.

In designating the shoreline type to be used to characterize each OCS planning area, the most common shoreline type was selected for each area, as established in Appendix I-1. For example, for the North Atlantic OCS planning area some 64 percent of the coastal habitat is sandy beaches, while about 31 percent is rocky beaches and about 6 percent is estuaries/wetlands (Appendix I-1). Hence, for this OCS area, spills coming ashore are assumed to do so on a sandy beach. The biological resources injured by oil spills in the North Atlantic OCS planning area, therefore, are those characteristic of this type of shoreline environment. Using this approach and the information from Appendix I-1, Table E.2 indicates the shoreline type used for each OCS planning area to measure intertidal damages from oil spills with the NRDAM/CME.

Finally, in the analysis that follows damages are averaged over all four seasons. Other environmental parameters used in the application of the NRDAM/CME to the sensitivity analysis of social costs are indicated



Table E.1. Reconciliation of OCS Planning Areas and CERCLA Provinces

| CERCLA Province | OCS Planning Area |
|---|---|
| Acadian | North Atlantic |
| Virginian | Mid-Atlantic |
| Carolinian | South Atlantic |
| West Indian | Straits of Florida |
| Louisianian | Eastern Gulf of Mexico<br>Central Gulf of Mexico<br>Westrn Gulf of Mexico |
| Californian | Southern California<br>Central California<br>Northern California |
| Columbian | Washington and Oregon |
| Fjord | Gulf of Alaska<br>Cook Inlet<br>Kodiak<br>Shumagin<br>Aleutian Arc |
| Arctic | Bowers Basin<br>St. George Basin<br>North Aleutian Basin<br>Aleutian Basin<br>Navarin Basin<br>St. Matthew Hall<br>Norton Basin<br>Hope Basin<br>Chuckchi Sea<br>Beaufort Sea |

Table E.2. Designation of Shoreline Type for Each OCS Planning Area for Use in the NRDAM/CME

| Planning Area | Shoreline type for NRDAM/CMEa/ |
|---|---|
| No. Atlantic<br>Mid. Atlantic<br>So. Atlantic | Sandy Bottom |
| Straits of Florida | Saltmarsh |
| Eastern Gulf of Mexico<br>Central Gulf of Mexico | Saltmarsh |
| Western Gulf of Mexico | Sandy Beach |
| Southern California | Sandy Beach |
| Central California<br>Northern California | Rocky Bottom |
| Washington/Oregon | Rocky Bottom |
| Gulf of Alaska | Sandy Beach |
| Kodiak<br>Cook Inlet<br>Shumagin<br>No. Aleutian<br>St. George Basin<br>Norton Basin | Rocky Beach |
| Hope Basin<br>Beaufort Sea | Saltmarsh |
| Chukchi Sea | Sandy Beach |

a/ The shoreline category in this column refers to the primary shoreline type as indicated in Appendix I-1.



in Table E-3. The assumptions that all subtidal spills occur in relatively shallow water, that all spilled oil comes ashore and that none is cleaned up are conservative, i.e., high-cost assumptions.

### E.3.4 Estimating Damages as a Function of the Expected Size of Spills

The NRDAM/CME model is used to calculate the damages which are expected to result from oil spills of various sizes. The damages included in this analysis do not include all damages; the categories of damages included in the NRDAM model are discussed above. These results were used to construct a damage function (damages as a function of quantity spilled) for each province. Given this damage function, expected damages per spill were calculated as:

$$\int_{1000}^{\infty} \text{Damages(Quan)}\ P(\text{Quan})\ d(\text{Quan}) \qquad \text{(E-1)}$$

so that expected damages from a randomly selected spill greater than 1000 barrels equals damages as a function of the size of the hypothetical spill times the probability of having a spill of that size, and integrating over all possible spill sizes greater than 1000 barrels. Thus, in order to calculate the expected damages from a spill, the damage function and the probability density function was constructed by assuming a log-normal density, as is typically assumed, (see, for example, Lanfear and Amstrutz, 1983) and calculating the average spill size, and the standard deviation of spills from DOI data on sizes of actual spills from each source (platform, pipeline and tankers).

The damage function is estimated by running the NRDAM/CME for spills of varying sizes and employing regression techniques to relate damages to the spill size. The functional form for the damage function needs to be specified in a manner sufficiently flexible to mimic the shape of the damages as a function of the quantity spilled. For this purpose, the following functional form was used:

$$\text{Damages} = A0\ \text{Quan}^{[A1 + A2*\ln(\text{Quan})]}$$

Thus, damages are assumed to be a power function of the quantity spilled, where the power may vary with the quantity spilled. This allows for damages with increase at an increasing or decreasing rate, depending on whether A1 + A2*ln(Quan) is greater than or less than one. This may be very important in determining damages as a function of the amount spilled, since preliminary results show that damages increase at an increasing rate for small spills (A1 > 1), but increase at a decreasing rate for larger spills (A2 < 0).

The functional form can be rewritten as:

$$\ln(\text{Damages}) = \ln(A0) + A1*\ln(\text{Quan}) + A2*\ln(\text{Quan})^2$$

Table E-3 Summary of Parameters Used in NRDAM/CME Model for Social Cost Sensitivity Analysis

| | |
|---|---|
| Environment: | Marine, Subtidal |
| Bottom Type: | Sand |
| Spill Date: | July 1, 1987 |
| Pychnocline: | Yes |
| Upper Water Column: | 10 Meters |
| Lower Water Column: | 20 Meters |
| Mean Ocean Current: | 0.1 Meters per Second |
| Tidal Velocity (Par.): | 0.2 Meters per Second |
| Tidal Velocity (Perp.): | 0.2 Meters per Second |
| Wind Speed: | 8.0 Meters per Second |
| Wind Direction: | 90 Degrees |

Presumed Air Temperatures by Province and Season:

| Province | Summer | Fall | Winter | Spring |
|---|---|---|---|---|
| Acadian | 10 | 5 | 0 | 5 |
| Virginian | 15 | 5 | 0 | 5 |
| Carolinian | 20 | 15 | 5 | 15 |
| Lousianian | 20 | 15 | 5 | 15 |
| West Indian | 25 | 20 | 10 | 20 |
| Californian | 20 | 15 | 5 | 15 |
| Columbian | 10 | 5 | 0 | 5 |
| Fjord | 5 | 0 | -10 | 0 |
| Arctic | 5 | -10 | -20 | -10 |
| Pacific Insular | 25 | 20 | 10 | 20 |



This is an example of the so-called trans-log flexible functional form. This form can be viewed as a second order approximation to any function, and thus allows for any combination of first and second derivatives of the damage function.

The model was run for 12 possible levels of spills, from 5 metric tons to 10,000 metric tons (37.5 to 75,000 barrels) for a summer spill in the Louisiana Province (i.e. the Gulf of Mexico). The damage function was then estimated through regression analysis assuming the trans-log functional form. Because damages for fisheries appear to behave differently than for birds, separate regressions were run for each. The expected damages to fish and to birds were then determined from the integral, Equation (E-1). The expected damages where then adjusted for other provinces by using running NRDAM for all provinces and seasons and calculated the average damages for all four seasons from a 100 metric ton spill (750 barrels). The expected damages for each province was then calculated as:

$$E(Damage_i) = Damage_i(100)/Damage_{LOU}(100) * E(Damage_{LOU})$$

where $Damage_i(100)$ is the damage in province i from a 100 metric ton spill, averaged over four seasons, $Damage_{LOU}(100)$ is the damage from a 100 metric ton spill in the Louisiana province during the summer, and $E(Damage_{LOU})$ is the expected damages in the Louisiana province during the summer, calculated from the integral, Equation (E-1).

Expected damages per barrel spilled are calculated by dividing the results of Equation (E-1) by the expected spill size for each source. Expected damages per billion barrels of oil handled are then calculated by multiplying this expected damage per barrel spilled for each area and source by the expected barrels spilled per billion barrels of oil developed for each source. The Damages can then be calculated by multiplying this figure by the estimated resources in each area to be handled by each potential spill source (platforms, pipelines and tankers).

## E.4 Results of Sensitivity Analysis

Using the assumptions and the approach described above, the damages per barrel of oil spilled have been estimated for each OCS planning area using the NRDAM/CME. Table E.5 compares the results of the NRDAM/CME approach with the approach used in Section II of appendix G. Each figure in the first column indicates the cost per barrel spilled using the unit-cost approach adopted in Section II of appendix G for direct commercial fishing losses and ecological costs, the two appendix G cost catagories most comparable to those used in the NRDAM/CME. For example, for the No. Atlantic the indicated appendix G cost per barrel spilled is $282.5, which is the sum of the direct commercial fish loss per barrel of $150.0 (Table II.A.2.1) and the ecological cost per barrel spilled of $132.5 (Table II.A.4.1) for this area. Using the NRDAM/CME, the cost per barrel spilled amounts to $24.8. Hence in this example, the simplified unit cost approach described in Section II of appendix G leads to costs per barrel spilled for the catagories concerned which are higher by $257.7 per barrel than the results using the NRDAM/CME. Therefore, had the NRDAM/CME been used to estimate the individual oil spill costs concerned

Table E.4. Calculation of Damages in Central Gulf of Mexico Using CERCLA Methodology

| Source | (1) Damages per Barrel Spilled ($/BBL) | (2) Barrels Spilled per BBO Handled (BBL/BBO) | (3) BBO Handled (BBL) | (1)*(2)*(3) Expected Cost ($ Million) |
|---|---|---|---|---|
| Tankers | $41.61 | 1.3 * 14,707 = 19,119 | 0.2 * 1.67 = 0.33 | $0.266 |
| Pipelines | $33.06 | 1.6 * 25,938 = 41,501 | 0.8 * 1.67 = 1.34 | $1.833 |
| Platforms | $43.30 | 1 * 18,378 = 18,378 | 1.0 * 1.67 = 1.67 | $1.329 |
| Totals | | | | $3.428 |
| Damages per BBL Spilled (Total Damages/Total Barrels Spilled) | | | | $37.047 |



for the No. Atlantic, with the approach described in Sections II and III used to estimate all other social and regional costs, considerably lower estimates of social and regional costs for this OCS planning area would have been obtained.

As indicated in Table E.3, for 18 of the 22 OCS planning areas, the cost per barrel spilled for commercial fishing and ecological costs using the simplified approach described in Section II of Appendix G results in a higher cost per barrel spilled than does use of the CERCLA NRDAM/CME, with most being considerably higher. Hence, for these 18 areas, the estimates of social costs for each OCS planning area presented in appendix G are higher than those which would be obtained if the cost per barrel spilled measured with the more sophisticated, NRDAM/CME was used to estimate social costs for each OCS area.

On the other hand, for 4 OCS planning areas the NRDAM/CME results in somewhat higher unit costs than the commercial fishing and ecological costs developed in section II to estimate social costs. This result suggests that had the social cost estimates been based on per barrel costs generated using the NRDAM/CME, the estimated social costs for these areas would have been somewhat larger than those presented in appendix G.

Table E.5. Comparison of the Cost per Barrel Spilled Using the Estimates in Appendix G With Those Obtained Using the CERCLA NRDAM/CME

| CERCLA Province | OCS Planning Area | Cost per Barrel Spilled: Appendix Ga/ | NRDAM/CMEb/ |
|---|---|---|---|
| Acadian | North Atlantic | $ 282.5 | $ 26.7 |
| Virginian | Mid-Atlantic | 261.8 | 13.8 |
| Carolinian | South Atlantic | 216.6 | 4.4 |
| West Indian | Straits of Florida | 203.9 | 60.7 |
| Louisianian | Eastern Gulf of Mexico | 127.8 | 37.6 |
| | Central Gulf of Mexico | 330.7 | 37.1 |
| | Western Gulf of Mexico | 172.8 | 11.4 |
| Californian | Southern California | 167.2 | 27.2 |
| | Central California | 173.3 | 210.4 |
| | Northern California | 176.3 | 210.4 |
| Columbian | Washington and Oregon | 257.3 | 140.2 |
| Fjord | Gulf of Alaska | 224.3 | 8.2 |
| | Cook Inlet | 228.7 | 84.1 |
| | Kodiak | 233.0 | 82.8 |
| | Shumagin | 216.4 | 84.1 |
| Arctic | St. George Basin | 233.7 | 250.7 |
| | North Aleutian Basin | 344.2 | 249.1 |
| | Navarin Basin | 49.7 | 8.6 |
| | Norton Basin | 227.4 | 249.1 |
| | Hope Basin | 319.7 | 32.0 |
| | Chukchi Sea | 125.9 | 30.2 |
| | Beaufort Sea | 202.0 | 30.4 |

a/ Each number in this column is the sum of the direct commercial fishing loss and the ecological cost per barrel of oil spilled developed in Section II (see Tables II.A.2.1 and II.A.4.1).

b/ The number in this column indicates the weighted average of the expected damages per barrel for each potential oil spill source (platforms-tankers-pipelines) for each of the costs considered in the NRDAM/CME except for damages to public beaches. The expected damage per barrel spilled for each source was weighted by the expected number of spills per billion barrels of oil produced or handled and the relative share of oil handled by tankers and pipelines for each area. The data and assumptions used to apply the NRDAM/CME to hypothetical oil spills in OCS planning areas are explained in the text.

# APPENDIX H

## GEOGRAPHICAL, GEOLOGICAL, AND ECOLOGICAL CHARACTERISTICS OF PLANNING AREAS
## OTHER USES OF THE OCS
## LEASING AND DEVELOPMENT HISTORY OF AREAS
## RELEVANT ENVIRONMENTAL AND PREDICTIVE INFORMATION

GEOGRAPHICAL, GEOLOGICAL, AND ECOLOGICAL CHARACTERISTICS OF PLANNING AREAS/OTHER USES OF THE OCS/LEASING AND DEVELOPMENT HISTORY OF AREAS/RELEVANT ENVIRONMENTAL AND PREDICTIVE INFORMATION

CONTENTS

## TABLES





# GEOGRAPHICAL, GEOLOGICAL, AND ECOLOGICAL CHARACTERISTICS OF PLANNING AREAS OTHER USES OF THE OCS/LEASING AND DEVELOPMENT HISTORY OF AREAS RELEVANT ENVIRONMENTAL AND PREDICTIVE INFORMATION

## I. Introduction

This Appendix describes the planning areas under consideration, focusing on their geographical, geological, and ecological characteristics. Other topics covered in this Appendix include other uses of the Outer Continental Shelf (OCS), the leasing and development history of planning areas, and relevant environmental and predictive information (a summary of the environmental studies program). Twenty-two planning areas are described, including two planning areas -- Straits of Florida and Washington-Oregon -- not previously included in the 5-year program.

This Appendix contains information which, according to section 18 (a)(2)(A) and (D) of the OCS Lands Act Amendments, must be considered in decisions regarding the timing and location of exploration, development, and production of oil and gas among the oil-and-gas-bearing physiographic regions of the OCS. This information concerns the geographical, geological, and ecological characteristics of OCS regions and the location of such regions with respect to other uses of the sea and seabed.

In addition to descriptions of planning areas, specific quantitative information is included in Tables H-1 through H-6. These tables present information concerning ecological characteristics, other uses of the sea and seabed, leasing and development history, environmental studies, and lease sale-specific environmental impact statement and oil-spill risk analyses by planning area. Maps showing the geographic location of planning areas are in Appendix M. Seismic information is included in Appendix E.

## II. Geographical, Geological, and Ecological Characteristics of Planning Areas

This section provides brief planning area descriptions. These descriptions focus on the planning areas' broad geographical, geological, and ecological characteristics. More specific information is provided on each planning area's regional geology, petroleum potential, and on specific geologic features considered to be hazards or constraints to operations. Also, following each planning area description is a short list of supplemental readings for reference. A table showing some ecological characteristics of planning areas is on page H-59 of this appendix (Table H-1).

Certain geologic features and conditions may jeopardize offshore oil and gas operations. Such features are generally known as geohazards. High-risk conditions are classified as hazards; lower-risk conditions that can be mitigated more easily are generally classified as constraints. In areas where such geohazards exist, special engineering procedures may be necessary or stipulations may be imposed. Constraints are usually considered merely developmental conditions: once they have been identified, existing standard design and engineering technology can be used to minimize their adverse effects.

## A. North Atlantic

The North Atlantic planning area includes Georges Bank and the Gulf of Maine on the continental shelf and extends seaward down the continental slope into deepwater on the continental rise. The slope shows some evidence of bottom instability while shifting sands, in the form of sand waves are common on the shelf. Strong currents are known to exist most of the year on the shallow portions of Georges Bank proper.

Average weather and sea conditions are not harsh, although extremes can cause navigation and other operational hazards. Reduced visibility due to fog is common during parts of the year.

The shoreline is primarily rocky, especially in the north, but scattered beaches occur throughout. Cape Cod and nearby islands are characterized by sandy shorelines. The major portion of the coastal area from Massachusetts south is intensely developed, but the actual shoreline is sparsely populated and undeveloped in many areas. Recreational and tourist use of the coastline is extensive.

Georges Bank is an area of high productivity and the site of spawning of commercially important species. Fisheries resources of the Bank, as well as fishery and other biological resources of submarine canyons, have been a major concern with respect to potential oil and gas activities. A biological stipulation is in force for all current leases in this area to ensure that appropriate monitoring is conducted and operations are conducted so as not to adversely affect biological resources. An interagency committee makes recommendations concerning implementation of the stipulation to the appropriate regulatory official. Another requirement applied in this area directs that oil and gas personnel be trained to recognize possible conflicts with fishing operations and to employ methods to reduce such conflicts.

### 1. Regional Geology

The North Atlantic planning area includes the Georges Bank Basin, the Gulf of Maine, and the deep water basin seaward of Georges Bank. The geology of the Georges Bank area consists of, as basic elements, pre-rift continental sediments capped by as much as 25,000 feet of syn- and post-rift marine and terrigenous deposits. The lithology appears mainly to be controlled by paleobathymetry and by distance from the ancient shorelines.

Pre- and syn-rift sediments are the erosional remnants of a thick section of Triassic and Paleozoic clastics, volcaniclastics, and freshwater deposits. These sediments are preserved in grabens and half grabens formed in crystalline and meta-sedimentary basement as a consequence of the rifting process. This graben fill was further faulted and deformed during several syn-rift orogenies. A regional erosional event subsequently planed off these sediments. This unconformity separates Triassic and older graben fill from overlying Triassic paralic sediments.

The rifting process continued in a number of distinct episodes from Late Triassic to Middle Jurassic time. Intrusion of marine waters after the initial rift resulted in the deposition of Late Triassic shallow marine and shoreline sediments including limestone, dolomite, and evaporites (mostly salt.) This section becomes enriched in clastics and coal to shoreward. Seaward, large



thicknesses of evaporites deposited in an arid shoreline environment were deformed by subsequent sediment loading and produced a number of diapirs in the northeastern part of the planning area. A widespread erosional unconformity caps the Triassic paralic/shallow marine sequences.

Renewed subsidence, probably associated with an early Jurassic rifting episode, resulted in the deposition of a widespread sand unit which was subsequently subaerially exposed. This unit is immediately above the Triassic unconformity. Rift-related tectonism ceased by Middle Jurassic when subsidence and sea level changes resulted in more open marine conditions and the consequent deposition of limestones. Some of these limestones were later altered to dolomite. Lowered sea level shortly after the beginning of the Late Jurassic produced a dramatic seaward shift in the limit of clastic sedimentation. Late Jurassic (and younger) sediments in the Continental Offshore Stratigraphic Test (COST) G-2 well are nearly totally clastics; sand, siltstone, and finer grained terrigenous deposits dominate the section.

Sea level has remained near its present level (except for short-term fluctuations) since about Late Jurassic time. Hence, Cretaceous and Tertiary sediments are nearly all sands, shales, and siltstones with occasional thin limestone beds.

Ocean basin subsidence relative to the continental margin had progressed to the point where a distinct shelf edge was formed by the middle of Late Jurassic time. This shelf edge provided a structural root for subsequent biohermal or reef development. The shelf edge complex including the carbonate buildup is discontinuously distributed parallel to the present shelf break throughout the planning area. Carbonate buildup persisted until some time in the Early Cretaceous when it ceased, probably because of sea level and/or climatic changes.

### 2. Petroleum Potential

Exploration for petroleum in the Georges Bank Basin began in April 1976 when the first of two COST wells was spudded. Eight additional wells were drilled by industry in 1981-82, all of which were dry.

The North Atlantic planning area can be conveniently divided into three areas of different hydrocarbon potential. These areas are the Gulf of Maine, Georges Bank Basin, and the deep water areas seaward of the continental slope. The petroleum potential of the Gulf of Maine and the deep water area is poorly understood because of limited data in those regions.

The most prospective part of the planning area is the Georges Bank Basin, a zone of thick sediments centered on the present shelf edge. This area includes the largest and most attractive exploration target in the North Atlantic--the Jurassic shelf edge (carbonate buildup). The carbonate buildup in the the Georges Bank area has not yet been drilled, but samples from equivalent strata to the northeast offshore of Canada (Scotian Shelf) had encouraging porosity and permeability, and showed evidence of hydrocarbons. Traps associated with the carbonate buildup are back-reef anticlines, stratigraphic pinchouts, and faulted anticlines and noses. The zone of thickest sediment also includes a zone of diapirs which trends southwest from the Canadian border.

Potential source and reservoir rocks in a number of wells have been analyzed. Source rock quality in terms of the type and quantity of thermally convertible kerogens is in the poor-fair range. Most of the kerogen is of terrestrial origin, and is thus considered gas prone.

Reservoir rocks in the thermally mature interval of the section tend to be tight with porosity ordinarily less than 5 percent. Sandstone as a distinct lithology is largely absent in the mature interval throughout most of the zone of thick sediments. Potential reservoir lithologies thus appear to be limited to limestones in which secondary porosity may have developed.

### 3. Geohazards

A number of geologic features found in the North Atlantic planning area present problems for drilling for oil and gas. When geologic features present problems that cannot be dealt with technologically, they are termed hazards; when geologic features present problems that can be reduced to an acceptable level, they are termed constraints. Hazards that have been noted in the North Atlantic are shallow gas, shallow faults, and sediment mass movement. Shallow gas occurs on the continental slope and shelf; shallow faults have only been reported to occur on the continental shelf. Neither shallow gas nor shallow faulting are major sources of concern as they rarely occur in the North Atlantic. The major hazard found here is sediment mass movement, which is found on the continental slope and upper rise. However, mass movement occurs quite often on the mid- and lower slope areas where slide features appear to be predominant. Canyons seem especially susceptible to mass movement; here the tidal currents are concentrated, undercutting the canyon walls, which weakens the sediment layers to the point where they slump, slide, or collapse into debris flows. Intercanyon areas are generally free from sediment mass movement with the exceptions of the slope in the vicinity of Alvin and Atlantis canyons and the vicinity of Munsen and Nygren canyons. The intracanyon mass movement is considered to be a contemporary process since there is no known present-day triggering mechanism, the intercanyon mass movement probably originated during Pleistocene glacial retreats, when large volumes of water and sediment were discharged onto the continental slope.

Buried channels, deep faulting, and erosion are the known constraints to drilling in the North Atlantic. Erosional constraints are posed by the presence of sand waves on Georges Bank proper. Constraints are more widespread in occurrence than the hazards. Buried channels are quite common and numerous on the Georges Bank Shelf and Slope, a few deep faults occur throughout the North Atlantic, and erosion occurs mostly on Nantucket Shoals, Georges Bank, and possibly along the continental rise. No data exist to confirm erosion on the continental rise but high-velocity currents have been recorded on the rise south of Nova Scotia.

### 4. Supplemental Reading

Carpenter, G. and Amato, R., 1984, Geology report: proposed North Atlantic OCS Oil and Gas Lease Sale N. 96: U.S. Minerals Management Service OCS Report 84-0062, 19 p.

Klitgord, K., Schlee, J., and Hinz., K., 1982, Basement structure, sedimentation and tectonic history of the Georges Bank Basin, in P. Scholle and C. Wenkam, eds., Geological studies of the COST Nos. G-1 and G-2 wells, United States North Atlantic Outer Continental Shelf: U.S. Geological Survey Circular 861, P. 160-186.



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Poag, C. W., 1982, Stratigraphic reference section for Georges Bank Basin - depositional model for New England passive margin: American Association of Petroleum Geologists Bulletin, v. 66, no. 8, p. 1021-1041.

Ziegler, D., 1983, Hydrocarbon potential of Newark Rift System, eastern North America: American Association of Petroleum Geologists annual meeting abstracts and program, v. 67, p. 574-575.

## B. Mid-Atlantic

The Mid-Atlantic planning area includes three major physiographic regions -- the continental shelf, the continental slope, and the continental rise. Large variations in both topographic and bottom stability along the slope are the chief potential geologic hazards. Meteorologic conditions are similar to those further north, though fog is generally not a problem in this area. Internal waves along the slope are of concern to drilling operations. High seas occur in winter and during tropical storms.

The shoreline is primarily beach, with extensive wetlands behind barrier islands, which are important spawning and nursery areas for the shellfish industry and other fisheries. Barrier beaches and wetlands of New Jersey, the Delmarva Peninsula and North Carolina (Outer Banks) are extremely important. While the coastal area between New York and Baltimore is urbanized, the shoreline, with a few exceptions, is characterized by low density development. Much of the beach front is built up with residential, including seasonal, dwellings and commercial development related to recreation and tourism. However, there are also protected, undeveloped shoreline areas. Recreation and tourism use of the shorelines is high.

Submarine canyons and a large commercial fishery are characteristic of the planning area, although the fishing activity is more dispersed than on Georges Bank. Stipulations to protect canyon resources and reduce conflicts with fishing, similar to those used in the North Atlantic planning area have also been utilized in this area.

### 1. Regional Geology

The Baltimore Canyon Trough is the major geologic feature of the Mid-Atlantic planning area. It consists of an elongated Northeast-trending depression averaging 100 miles in width and extending from roughly Virginia Beach to Long Island. Sediment thickness in this basin exceeds 50,000 feet. The included sediments range in age from Triassic to Recent with most of the Section being of Jurassic age.

Pre-rift and syn-rift sediments (Triassic and older) occur in a NE-SW trending series of grabens and half-grabens which developed in basement rock as a result of the rifting process. Pre-rift rocks also cover unfaulted crystalline and meta-sedimentary basement over much of the planning area. These sediments are preserved as erosional remnants and consist primarily of continental clastics, volcanics, evaporites, and freshwater deposits. Pre-rift sediments are capped by a prominent regional erosional unconformity (the breakup unconformity) which is well defined on seismic data.

Rift-related tectonism ceased by lower Jurassic time and the post-rift intrusion of marine waters resulted in deposition of shallow water, oolitic limestones, The limestones are interbedded by marginal marine clastics and swamp deposits. Much of the Jurassic section in the COST B-2 and B-3 wells resembles the classic coal cycle (cyclothem) of marsh deposits grading into shallow marine lithologies. Paleo sea level apparently remained near the position established in Jurassic time until well into the Cretaceous as evidenced by coal beds in that part of the section.

Rifting had progressed to the point where the present shelf/basin structural configuration had developed in Jurassic time. The resulting shelf edge became a locus for "reef" growth in the Jurassic and ended in the Early Cretaceous when growth ceased, probably because of climatic or sea level changes. The upper, seaward face of the reef is cut by a prominent erosional unconformity which may have resulted in development of secondary porosity in that portion of the reef.

Salt deposition, probably near the beginning of the post-rift phase, resulted in scattered occurrences of deep-seated salt diapirs. The "Texaco-Tenneco" structure (Blocks 598, 599, 642, 643), about 30 miles Southwest of Hudson Canyon, may have a salt core. Other, scattered intrusives are sparely distributed throughout the planning area. The largest structural feature in the Baltimore Canyon Trough (Stone Dome), is believed to be an igneous plug.

Cenozoic sediments consist mostly of poorly consolidated sands, mudstones, clays, and marls deposited in shallow water. Relatively deep, open marine conditions prevailed for most of the Eocene, and resulted in the deposition of a thick sequence of limestones which grade into marls and calcareous mudstones to landward. Surface sediment is mostly sand and unconsolidated mud.

2. Petroleum Potential

The first deep stratigraphic test well (COST B-2) in the Mid-Atlantic planning area was drilled in 1976. COST B-3 was drilled in 1978 and was followed by 32 industry exploratory wells. Except for five wells drilled on a single large structure (Texaco-Tenneco structure) which discovered significant quantities of gas and condensate, all the industry wells were dry. (The B-3 well, located about 30 miles southwest from this structure encountered a show of gas from a 6-foot zone below 15,000 feet.)

The most prospective part of the Mid-Atlantic planning area is the zone of thick sediments in the Baltimore Canyon Trough. The "Reef Trend" and its associated fore and back reef structures are considered part of this zone. Several wells drilled in 1984 on and near the reef were dry.

Potential source and reservoir rocks in a number of wells have been analyzed. Source rock quality is generally in the poor-to-good range with regard to the type and quantity of proto-hydrocarbons. Much of the kerogen is terrestrial in origin indicating most of the generated hydrocarbons would be gas rather than



oil. Presumably, the potential for oil would increase to seaward where the proportion of algal, oil-prone kerogen would be expected to increase. In the sedimentary section in the Baltimore Canyon Trough that is considered thermally mature for hydrocarbon generation, source rock shales tend to be lean in organic matter (usually less than one percent).

Reservoir rocks below 10,000 feet are limited to sandstones with relatively low porosity and permeability. Some development of secondary porosity by dolomitization of limestones has been observed, but is considered only of local significance. Well log interpretations show that only a small fraction of the total sand thickness below 10,000 feet has porosities greater than five percent. Permeability is low because of infilling of intergranular voids by calcitc cement and contamination by clay-silt sized sediment.

3. Geohazards

Sediment mass movement is the major geologic process which could be hazardous to oil and gas drilling in the Mid-Atlantic planning area. Mass movement, restricted in occurrence to the continental slope and rise, is considered the dominant process shaping the submarine canyons. The canyons serve to focus tidal currents and possible Gulf Stream eddy currents which, in conjunction with bioerosion, undercut the canyon walls, weakening the sediment layers to the point that they slump, slide, or collapse into debris flows. There is evidence that this is a present day process in many of the canyons; however, for unknown reasons, some of the canyons appear to be quiescent. The intercanyon ridges show evidence of widely scattered mass movement. The area between Mey and Hudson Canyons seems to be an exception. The majority of the slope in this area has undergone some kind of mass movement, most of which consists of differential compactions. Most authors indicate that intercanyon mass movement features are probably Pleistocene in age and not a contemporary process. Additional hazards which have been noted in the Mid-Atlantic are very widely scattered. Shallow faulting of apparently recent occurrence has been observed on the shelf and slope and shallow gas has been noted on the shelf, slope, and rise. The most widespread potential for shallow gas may be in the zone of clathrates (frozen gas hydrates) which occurs along the continental rise from 2,500 m to 3,800 m deep. Clathrates can cap gas deposits that are overpressured.

Other geologic features found in the Mid-Atlantic area that can have adverse effects on drilling are seafloor scour, filled channels, shallow faults (with no recent movement), and gassy sediments. These features occur only locally and are considered constraints as current drilling technology can reduce the adverse effects to an acceptable level.

4. Supplemental Reading

Amato, R., and Simonis, E., eds., 1979, Geologic and operational summary COST N. B-3 well, Baltimore Canyon Trough area, Mid-Atlantic OCS: U.S. Geological Survey Open-File Report 79-1159, 118 p.

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Giordano, A., Carpenter, G. and Amato, R., 1984, Oil and gas developments in Atlantic Coastal Plain and Outer Continental Shelf in 1983: American Association of Petroleum Geologists Bulletin No. 10, p. 1407-1411.

Miller, R., Schultz, D., Claypool, G., Smith, M., Lerch, H., Ligon, D., Owings, D. and Gary, C., 1980, Organic geochemistry, in United States Mid-Atlantic Continental Slope area: U.S. Geological Survey Circular 833, p. 85-104.

Weeks, L. G., 1974, Petroleum resources potential of Continental Margins, in The Geology of Continental Magins, C. A. Burke and C. L. Drake eds: Springer-Verlag, p. 953-964.

C. South Atlantic

The most promising geologic features of the South Atlantic lie close to the shoreline in the vicinity of Cape Hatteras, but otherwise prospective areas are located roughly 25 to 75 miles offshore from the coastline. Geohazards include historic seismicity, localized bottom instability, scouring, and faulting. Strong currents of the Gulf stream and its eddies prevail.

The South Atlantic experiences hurricanes with regularity, which probably present the greatest weather hazard to offshore operations in the area.

The shoreline is characterized by extensive barrier islands backed by wetlands. The wetlands are an important habitat for coastal birds as well as spawning grounds for fish and shellfish and important nesting areas for marine turtles. The endangered manatee inhabits the coastal waters. Extensive beds of submerged aquatic vegetation also occur in the South Atlantic and are of particular importance to the shrimp industry.

Although the submarine canyons that can be found further north do not exist south of Cape Hatteras, some especially productive marine communities exist in the vicinity of rocky formations or other hard substrate--known as live bottoms. These include coral reef structures. Stipulations have been developed and applied in the past to protect these resources, including requirements for monitoring, restrictions on disposal of drill cuttings and fluids, and possible relocation of drilling operations.

Industrial use of the coastline, including major ports, is characteristic of urban areas, and some portions of the coast are quite well developed for recreation and tourism use, including significant barrier island development. Nonetheless, large stretches of coast are relatively undeveloped.

1. Regional Geology

The South Atlantic Planning Area contains three major sedimentary basins: the Carolina Trough, Southeast Georgia Embayment, and the Blake Plateau Basin. The geology of the South Atlantic is less well known than other planning areas mainly because it has the largest number of major basins and the fewest wells (7). The industry exploration effort has been concentrated in the Southeast Georgia Embayment, the smallest, and geologically, the least attractive sedimentary basin.



The most important rocks in the Atlantic OCS for hydrocarbon exploration are of Jurassic age. Jurassic rocks are absent in the Southeast Georgia Embayment and the sedimentary section is generally only about 10,000 feet thick. The lower, thermally mature part of the section is largely composed of Cretaceous continental clastics with poor source rock characteristics. These sediments rest on an unconformity above Paleozoic meta-sedimentary basement rocks. Sediments are flat lying (essentially a submerged coastal plain), and include few large structural traps.

The Carolina Trough is a narrow, linear basin approximately 280 miles long and 25 miles wide which contains over 30,000 feet of sedimentary fill. The rocks range in age from Triassic to Recent with most of the section being of Jurassic age. The Carolina Trough has never been drilled, but seismic data indicate that the Triassic rocks are probably continental clastics deposited prior to ocean basin rifting. The Jurassic rocks are probably limestones and dolomites with clastic interbeds. The carbonates either grade landward to clastics or pinchout entirely. The Cretaceous and younger sediments are believed to be mostly sand and shale with carbonates occurring as a second order component in clastic rocks, e.g. marls, clacareous mudstones, etc.

The Blake Plateau Basin is the largest sedimentary basin off the U.S. East Coast. There are no deep exploratory wells in the basin but speculations regarding the probable lithologies have been made. Most of the basin is probably floored by basement generated during the rifting process. Sediments above basement are mostly limestones and dolomites, which are over 30,000 feet thick in the axis of the basin. Well over half of the total thickness is Jurassic in age with most of the remainder being Cretaceous. Basin subsidence had apparently ceased by the close of the Cretaceous period, since the Tertiary section is extremely thin. The surface of the Blake Plateau is swept by strong bottom currents that currently prevent further deposition.

2. Petroleum Potential

The petroleum potential of the South Atlantic Planning Area is poorly known, largely due to the lack of exploratory well data. The first deep well in the planning area was the COST GE-1, which was completed in 1977. This was followed by six industry wells spudded in 1979 in the Southeast Georgia Embayment, all of which were dry. Geological analyses of these wells indicate limited hydrocarbon potential, therefore, the probability of further exploratory drilling in this basin is probably slight.

The Carolina Trough appears to offer good potential for hydrocarbon generation and retention. It has sufficient sediment thickness to ensure an interval of thermal maturity, a large number of attractive traps, and the section may include oil-prone source rocks. A thick regional salt bed, deposited immediately after rifting ceased, has been deformed by sediment loading, producing a number of diapirs on the seaward edge of the basin. A growth fault on the continental slope associated with salt flow may provide other traps. Other faults are common within and on the margins of the basin.

The Blake Plateau Basin may offer attractive possibilities for commercial accumulations of hydrocarbons. The basin is large in area and may contain thermally mature marine sediments that may be oil-prone rather than gas-prone because of the presence of algal kerogens. The basin probably has been tectonically stable since Lower Jurassic time, as the sediments appear unaffected by faulting or deformation. The few structures identified tend to be large with very low relief. A carbonate buildup trend is evident, but is Cretaceous in age and probably thermally immature.

3. Geohazards

Geological features hazardous to drilling are very sparse in shallow water areas of the South Atlantic. Hazards to drilling are fairly prevalent in the deepwater areas of the region where mass movement features, active faults, and clathrates (frozen gas hydrate) exist. The lack of a steep, canyon-incised slope and the low sedimentation rate in much of the area, due to the Gulf Stream sweeping the seafloor clean, eliminates much of the sedimentary environment in which geohazards are most often found. Hazards that do exist in the South Atlantic are surficial sediment collapsed into cavernous (karst) topography, sediment mass movement, and shallow gas. The collapse of surficial sediments has been observed on the shelf of northern Florida and Georgia in places where portions of shallow carbonate rocks have dissolved, leaving the surficial sediments without support. Similar conditions exist on the Blake Plateau where the presence of shallow karstic carbonates could result in surface collapse. With the ubiquity of carbonates in the South Atlantic, there is the possibility that surficial sediment collapse may be a problem in other areas as well as those just mentioned. A true continental slope occurs along the eastern portions of the Carolina Trough and Blake Plateau. Mass movement appears to be common throughout the slope, particularly between 35° N. and 31° N. latitudes. Those mass movements that have occurred appear to be fairly recent. A major growth fault occurs along the eastern edge of the Carolina Trough and Blake Platform. This fault is related to salt diapirism and, as such, appears to be active. The potential for shallow gas is highest on the slope and upper rise of the eastern Blake Plateau where clathrate (frozen gas hydrate) layers can act as caps, forming shallow gas pockets. These clathrate layers extend northward through the eastern end of the Carolina Trough and into the Mid-Atlantic region. Therefore, potential for shallow gas exists throughout the extent of the clathrate layers.

Of the various constraints to drilling found in the South Atlantic (i.e., scour, shallow buried faults or deep faults, filled channels, and gassy sediments), the most notable is scour. Cape-associated shoals are highly mobile and areas of the outer shelf, slope, and Blake Plateau are intensely eroded by the Gulf Stream and associated currents. Shallow buried faults are common in parts of the South Atlantic. These features could act as conduits for overpressured gas if the two features occurred in conjunction with each other.

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D. Straits of Florida

The Straits of Florida planning area includes the Florida Keys, Florida Bay, Biscayne Bay, and southern Florida coastal and offshore region up to the southern boundary of the South Atlantic planning area (28° 17'10" N. latitude ). The planning area consists of a very shallow shelf area that is very large (spatially) north and west of the Keys and the Dry Tortugas, and very narrow to the south and east. The continental slope south and east of the Keys is fairly steep.

The Straits of Florida could be affected by tropical storms or hurricanes slightly more than the remainder of the Gulf of Mexico because of a preferred path between Cuba and Florida over the warm waters of the area.

The mainland coast of the Straits of Florida is composed of mangrove and marsh areas with little or no urban development. The Keys, however, are relatively well developed with tourist oriented commercial and residential land use. Preservation areas exist in the Straits including Everglades National Park and numerous State recreation areas.

Several endangered and threatened species occur in the Straits of Florida planning area: critical habitats of the Florida manatee, American crocodile, and Cape Sable sparrow; American alligator; Key deer; Key Largo cotton mouse and wood rat; right, fin, humpback, sei, and sperm whales; bald eagle, and peregrine falcon; wood stork; green and loggerhead sea turtles; Schaus swallowtail butterfly; Atlantic salt marsh snake; and Key tree cactus.

1. Regional Geology

The continental shelf and slope is a continuation of the Florida platform, which is composed of Mesozoic-Cenozoic carbonates. The Florida Straits shelf area has been removed since Mesozoic times from the major locus of rapid sedimentation. In particular, Pleistocene sediments which attain great thicknesses over the continental shelf of the rest of the northern Gulf of Mexico are virtually nonexistant in the Florida Straits shelf. The South Florida Keys are swept along their southern edge by the Gulf Stream. The higher features of the shelf are Pleistocene coral and oolite reefs. The higher of these reefs are emergent as the Florida Keys and extend from the Marquesas to Key Biscayne.

The dominant lithologies of the Straits of Florida area are carbonates deposited in the South Florida-Bahama Basin encompassing southeastern and southern Florida and the Bahamas. The post-Triassic section is nearly totally chalks, limestones, dolomities, and unconsolidated lime muds of shallow water origin. Evaporites and chert are important secondary lithologies. Triassic (and perhaps Lower Jurassic) rocks are arkosic sandstones and volcaniclastics deposited in grabens and half grabens developed in Paleozoic/Mesozoic crystalline basement as a consequence of rifting. These rocks are separated from the overlying Jurassic and younger carbonates by a prominent regional unconformity.

2. Petroleum Potential

Although a considerable thickness of carbonate strata is present in the Straits of Florida, the straits is lacking in carboniferous bearing strata and structural traps. The hydrocarbon bearing potential for the Straits of Florida has to be considered low.

The petroleum potential of the Straits of Florida region is difficult to assess. Test well results have produced only spotty indications of hydrocarbons, but analogous, carbonate provinces (i.e., the Middle East) have enormous production.

Commercial hydrocarbon accumulations have not yet been discovered in the Straits of Florida region but minor production occurs in areas peripheral to the region (northwest coast of Cuba, Sunniland trend in central Florida). These small fields produced from carbonate reservoirs of Jurassic age and the oil and gas may have originated from carbonate source rocks. (Carbonates are not commonly considered to be good source rocks).

Sediment thickness is variable throughout the region to a maximum of about 25,000 feet. Wells drilled in Bahamian territory indicate much of the section has been flushed by circulating water. This has resulted in locally excellent porosity (occasionally cavernous) but has also driven out any in-situ hydrocarbons. Much of the limestone in the deeper parts of the section has been altered to dolomite, which can result in significant improvement in secondary porosity.

Deposition of evaporites in the Jurassic has not produced large numbers of diapiric structures. Anhydrite and halite beds may be too thin or lack the overburden required to induce plastic flow.



3. Geohazards

The southern Straits of Florida (from 26° South) have complex geologic structure with a resultant geomorphologic environment that includes several seafloor processes: slumping, growth faulting, down-to-the-basin tectonic faulting, solution-formed karst, and possibly submarine currents. The northern Straits of Florida, from 26°N to 28°N, have a simpler geologic history and structure. The major process of concern here is solution-formed karst. The Pourtales Terrace in the southern straits and the Miami Terrace in the northern straits have very rugged and complex topographies that are the result of carbonate solution and the formation of sinkholes. The faulting in the southern straits has produced a very steep slope and several escarpments tens of meters high. Whether the faulting, either the shallow or deep, is active at present is not known. In some areas of the southern straits the slumping along the over-steepened Florida escarpment appears to have been possibly post-Pleistocene.

A major constraint exists in the Straits in the form of scour. Sandy areas of the Straits are readily scoured by vigorous Gulf Stream activity. Other constraints that may exist are shallow faults, filled channels, and gassy sediments.

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E. Eastern Gulf of Mexico

The Eastern Gulf of Mexico planning area is situated off the western or Gulf coast of Florida. This planning area is characterized by numerous potential hydrocarbon structures, which are distributed throughout the planning area. Submarine karst topography, especially along either shelf break, is a potential geologic problem to be faced for oil and gas operations.

Tropical storm activity is the dominant weather factor affecting operations. The Loop Current has considerable influence on water velocities in a large part of the Eastern Gulf.

As in the South Atlantic, the seafloor in the Eastern Gulf is characterized by scattered patches of hard substrate which often support highly productive communities of coral, fish and other marine resources, depending on water depth.

The best known is the Florida Middle Grounds. Stipulations like those developed to protect similar resources in the South Atlantic have been developed to protect such biological resources in the Eastern Gulf.

The coastline consists of marshes, mangrove swamps, mud flats and lagoons, sometimes fronted by beaches and barrier islands. Extensive beds of submerged aquatic vegetation occur in the Eastern Gulf of Mexico. These are of particular importance to the shrimp industry. The shoreline is relatively undeveloped, but heavily used for recreation and tourism. Commercial fishing as well as tourism is of economic importance.

Several endangered and threatened species occur in the Eastern Gulf planning area: critical habitats of the Florida manatee, Choctawatchee beach mouse, and Perdido Key beach mouse; bald eagle; peregrine falcon; wood stork; right, fin, humpback, and sperm whales; Kemp's ridley, green, hawksbill, leatherback, and loggerhead sea turtles; American alligator; and Okalossa darter.

1. Regional Geology

The Eastern Gulf of Mexico (EGOM) Planning Area lies offshore from the States of Alabama and Florida. Physiographically the area is mainly underlain by the West Florida Shelf, Terrace, and Escarpment which constitute the Florida carbonate platform and is composed of a thick Mesozoic-Cenozoic sequence of primarily carbonate bank deposits. The western margin of the area consists of the terrigenous clastic province of the Mississippi/Alabama/DeSoto Slope, Mississippi Fan, and Florida Plain. Very few wells have been drilled in the EGOM so that most of what is known about the stratigraphy has been inferred from seismic records and by projection from on shore.

Prospective hydrocarbon traps in the northwest portion of the EGOM are primarily in extensions of Jurassic and Cretaceous trends from the north. The Destin Anticline is a large (12 x 50 miles), NW-SE trending structure formed over a salt swell. Several dry holes were drilled on the eastern portion of this structure but excellent reservoir rocks were found in the Norphlet formation (Upper Jurassic). The crest of the structure is presently being explored and is still considered to have potential. There is a field of salt diapirs (DeSoto Diapir Field) located southwest of Destin that is also being explored.

The middle Ground Arch is a NE-SW trending high lying between the Suwanee Basin and the Central Florida Trough. Potential targets are structural and stratigraphic traps in Jurassic strata onlapping Paleozoic metamorphic rocks around the edge of the Middle Ground Arch.

The Central Florida Trough is a westward plunging basin with more than 16,400 feet of pre-Middle Cretaceous sediments near the edge of the Florida Scarp. Potential targets are structural and stratigraphic traps in Jurassic and Lower Cretaceous strata onlapping Paleozoic igneous and metamorphic rocks.

The Central Florida Arch received less sediments than the troughs to either side. There should however, be potential structural and stratigraphic traps in the shelf and slope areas.



The South Florida Basin encompasses an area of about 75,000 square miles and extends from the Peninsula Arch on the east to the Florida Escarpment on the west. Eleven oil fields have been discovered in this basin on the Florida mainland. The fields are associated with magnetic highs and noses on the north-eastern rim of the basin. Production occurs between 11,320 and 11,890 feet. The offshore part of the basin has not been fully tested and could be prospective.

The West Florida slope consists of the West Florida Terrace and West Florida Escarpment, which extend from the DeSoto Slope south to the Straits of Florida The escarpment is a constructional slope built up of shelf edge carbonate deposits and reef growth during Early Cretaceous time. Samples from the area show a lack of high energy facies indicating that the escarpment is an erosional feature. Limestones and deep water chalks ranging in age from Late Cretaceous through Pleistocene unconformably overlie older, shallow water carbonates.

The DeSoto Slope in the northwestern part of the EGOM is underlain by a thick sequence of sediments folded and arched by isolated salt domes and pillars. Regional growth faults parallel the shelf edge and may contain traps on the down-thrown side. Peripheral and radial faulting associated with salt structures may contain potential traps.

The Mississippi Fan is a broad, thick arcuate accumulation of Pleistocene, shallow water sediments extending nearly 375 miles from the Mississippi Delta to the abyssal plain. It covers an area greater than 111,970 square miles and is 2.8 miles thick in its thickest portion. It consists of a series of coalescing fan lobes. Thick sand sequences are present and the hydrocarbon potential is as yet untested.

2. Petroleum Potential

The EGOM is primarily a carbonate province. There is production onshore in the South Florida Basin from the Lower Cretaceous Sunniland Formation. Production also occurs in the Florida Panhandle from Jurassic sediments. As of July 1, 1986, 33 wells have been completed in the EGOM and at present there is no offshore production.

Source rocks in the EGOM are predominantly marine shales and organic rich carbonates ranging in age from Jurassic to Cretaceous. Cenozoic rocks may be important sources in deeper water. Tertiary sediments do not appear to have a promising suite of source rocks. Reservoir rocks range in age from Jurassic to Cretaceous. Jurassic reservoir rocks are primarily grain supported wakestones, packstones and grainstones, dolomites and some mudstones. Prospective Cretaceous reservoir rocks are deltaic and turbidite sandstones, carbonate reefs developed on the landward side of positive blocks and shell zones. Many potential traps exist in the EGOM including anticlines and faulted anticlines, structural closure against normal and growth faults, and a variety of stratigraphic and reef traps.

3. Geohazards

There are five kinds of geologic features in the EGOM which could become potential hazards: carbonate buildups, karst topography, channelization, seafloor instability and sand movement.

Carbonate buildups occur southwest of Florida Middle Ground Reef. Six north-south trending ridges occur in water depth of 120-240 feet. They may be analogous to geomorphic spits with reef deposits on top. The largest lies due west of Tampa and is called the Elbow. Farther to the south a similar feature called Howell Hook occurs. Another series of reefal ridges is located along the shelf edge. Carbonate buildups in the form of pinnacle reefs are located near the shelf break bordering DeSoto Canyon. Individual coral heads occur on the inner shelf.

Karst structures are located in two bands on the inner shelf with the innermost being coincident with the locations or reported sinks and springs. The outer belt is 5 miles wide and 50 miles long. Well dissected solution features are distributed in a 12 mile wide band in the central shelf interspersed with the Middle Ground reefs. There are also karst features adjacent to Pulley Ridge on the south. Isolated karst features are buried under the outer shelf. Large, well developed channel complexes occur in the central shelf extending from Tampa to south of Charlotte Harbor.

A large mass of sediment at the base of the slope at 26°N has been identified as a massive slump apparently the result of sediment overloading on the Upper Slope resulting in sea floor instability. The origin of this sediment was the high biological productivity created by the impingement and upwelling of nutrient-rich water on the shelf. While the bulk of the inner shelf sediments appear to be relict, the shelf edge appears to be a major depocenter for recent sediments and therefore conditions for mass wasting exist. Sediment slumping is presently occurring on the upper slope from 25°40'N to 25°N. Block slides have occurred on the Central Slope south of 26°N.

There are six major areas of mobile sand in the EGOM. The first area parallels the West Florida Peninsula out to water depths of 60 feet and is characterized by giant to large scale bed forms. The second area is located in the shallow water region of the Big Bend area out to mid shelf. The topography consists of low relief swells and scattered giant to largescale bed forms. Area three extends north and south of the Middle Ground out to water depths of 180 feet and has small scale features. The fourth area is situated near Cape San Blas and consists of giant sand waves out to depths of 130 feet and small scale bed forms out to 270 feet of water. Area five covers the outer shelf and ranges from low relief swells to large scale bed forms. A sixth area of giant sand waves is located between Howell Hook and the shelf break. Faulting is not well documented in the Eastern Gulf and in fact may not be significant as potential hazards in the EGOM.

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F. <u>Central Gulf of Mexico</u>

The Central Gulf of Mexico planning area is situated off the coasts of Alabama, Mississippi, and Louisiana. This planning area is characterized by many small hydrocarbon producing structures, dispersed throughout the area. Many more potential hydrocarbon structures exist in deeper waters of the continental shelf and slope. Mudflows and slumps in the Mississippi Delta vicinity and along the continental slope, and shallow faults and gas-charged sediments are the greatest geologic hazards to offshore development. Hurricanes are the weather factor most influencing operations and facility design.

Several endangered and threatened species occur in the Central Gulf planning area: critical habitats for the Alabama and Perdido Key beach mice, and Mississippi sandhill crane; fin, humpback, sei, and sperm whales; Eskimo curlew; bald eagle; peregrine falcon; brown pelican; American alligator; and Kemp's ridley, green, leatherback, and loggerhead sea turtles.

Extensive wetlands, vital for production of the valuable Gulf coast commercial fish and shellfish, are the dominant coastal features. These are also important for wintering birds. However, the coastal zone of this planning area also supports the greatest extent of oil and gas infrastructure in the U.S., if not the world, and hosts extensive commercial shipping in its ports (New Orleans, Mobile) as well.

Offshore, scattered topographic high features correspond to areas of especially high productivity, including fisheries resources. These features are similar to those in the Western Gulf and special stipulations, like those applied in the Western Gulf, have been used to protect them. This area supports a large commercial fishery.

1. Regional Geology

The Central Gulf of Mexico (CGOM) Planning area encompasses the Continental Shelf off the Louisiana Coast, the area east of the Mississippi Delta off the Mississippi and Alabama coasts to the eastern edge of Mobile Bay and the deeper water areas of Mississippi Canyon, Atwater Valley, NG 16-4, Green Canyon and Walker Ridge. The area is largely a Mesozoic-Cenozoic Basin with a series of thick Cenozoic depocenters which have shifted seaward with time to a Pleistocene depocenter at the shelf edge.

Structural deformation in the Gulf of Mexico since mid-Cretaceous time has been primarily in response to heavy sediment loading. Mesozoic and Cenozoic sediments have been upwarped, folded, and diapirically penetrated by plastic flowage of thick Jurassic salt deposits. Large contemporaneous or growth faults are also major structural features of the CGOM. Peripheral and radial faulting are typically associated with diapirism. Structural and stratigraphic traps are usually controlled by one of these features. In some areas undercompacted shales have deformed plastically in a manner similar to the salt and are responsible for some of the mounding and diaprism in various locations.

The geologic province of the CGOM is composed of a thick sequence of clastic sediments deposited in offlapping wedges that have been deformed by the movement of salt and undercompacted shale during Cenozoic time. Older Mesozoic trends occur in Late Jurassic reservoirs which extend across southern Mississippi and Alabama and into State waters near Dauphin Island, Alabama. Recent drilling has confirmed the extension of this trend southeastward into the Federal Outer Continental Shelf (OCS). There are several prospects of Jurassic age located in the very northeastern part of the CGOM. Oil and gas presently are being produced onshore from Lower Cretaceous sandstones and carbonates along a trend from Texas to southwestern Alabama. Prospective Lower Cretaceous reservoir rocks probably occur under the OCS off Mississippi and Alabama in the form of deltaic and turbidite sandstones, carbonate reefs and shell zones. Deep Tuscaloosa sands of Upper Cretaceous age extend in a band across south Louisiana and are prolific gas producers. This deep Tuscaloosa gas trend may extend southeastward across the eastern Louisiana/Mississippi continental shelf and slope.

Throughout Cenozoic time clastic sediments poured into the Gulf of Mexico Basin from the north and west. There are five major producing trends in the CGOM: Lower Miocene, Middle Miocene, Upper Miocene, Pliocene and Pleistocene. Prior to the Miocene the major source of sediment supply was from the west carried by the ancestral Rio Grande and Brazos River systems. As the major supply of sediment shifted to the north and the Mississippi River system became the major sediment carrier so too the major depocenters shifted to the northern rim of the Gulf. The oldest producing Cenozoic horizon in the CGOM is Lower Miocene. Miocene production extends from east of the Mississippi Delta into the Western Gulf of Mexico (WGOM) Planning Area. Production is primarily from deltaic sands. There was a gradual southward shift of depocenters during the Lower, Middle, and Upper Miocene. The maximum accumulated sediment thickness exceeds 20,000 feet. Pliocene sediments were also deposited in a deltaic environment and attained an aggregate thickness of 8,200 feet. Production extends from east of the Mississippi Delta into the High Island areas in the WGOM Planning Area. Pliocene production also continues beneath the Pleistocene in the Pliocene/Pleistocene producing trend.



The Pleistocene depositional environment was similar to the Miocene/Pliocene. Although numerous small transgressions and regressions occurred, in general, regression prevailed. There was a large increase in sediment supply from the glaciated areas to the north. The Pleistocene depocenter lies along the shelf edge south of Louisiana where 15,000 feet of Pleistocene sediments have been penetrated. Total thickness may exceed 20,000 feet. Pleistocene production will probably exceed all other producing horizons.

Many large structures occur on the continental slope which forms the southern part of the CGOM. Production has already been established at several locations on the slope in water depths approaching 1,000 feet. The area is underlain by Pleistocene and Pliocene sediments and structures, which were formed in response to sediment loading on the underlying salt and shale.

2. Petroleum Potential

The CGOM includes the very mature region of the Louisiana shelf and the frontier areas of the Mississippi-Alabama shelf and the deep water slope province. The CGOM contains approximately 450 oil and gas fields which range in age from Miocene to Pleistocene.

Source rocks for the CGOM consist primarily of organic rich shales which range in age from Lower Cenozoic through Pleistocene. Potential Mesozoic source rocks occur in the CGOM east of the Mississippi Delta. East of the delta, reservoir rocks in the CGOM range in age from Jurassic through Cretaceous. Reservoir rocks in the CGOM south of Louisiana consist primarily of sands ranging in age from Miocene through Pleistocene. The producing horizons grow progressively younger in age in a seaward direction. There are numerous structural and stratigraphic traps in the CGOM. Types of traps include anticlines and faulted anticlines formed by deepseated salt and shale ridges, salt and shale domes and salt massifs, and structural closure against normal and growth faults. Stratigraphic traps include sands onlapping salt and shale domes and anticlines, and facies changes from sands to impermeable shales in updip directions and at angular unconformities. In the portion of the CGOM east of the delta, prospective traps occurring in the Jurassic and Cretaceous updip sections where sand or porous carbonates pinch out or truncate updip, anticlinal structures developed on the down thrown sides of growth faults over deep seated salt domes and pillows, and very subtle fault closures.

3. Geohazards

The Southwest Louisiana Shelf and Slope, within the Pleistocene Trend, contains geologic features which must be considered as posing potential operational constraints to exploration and production activities. The following conditions pose potential operational constraints:

1. Shallow overpressured gas is widely distributed.

2. Buried stream channels are widespread and variable. Abrupt changes in bearing capacity of the channel fillings and gas prone sediments must be considered.

3. Many faults reach the surface or terminate just below it. Small escarpments and offsets of recent deposits indicate that gravity faulting and sediment adjustment is presently active.

4. Surficial slumping is most common around diapiric structures and on steeper slopes near the shelf edge. There are buried older slumps that can pose engineering problems. Slumping is more common on the continental slope.

5. Diapiric structures dominate the upper continental slope and are common on the shelf although usually more deeply buried. Numerous faults and fault scarps are associated with the structures, with some actually coming to the surface. The diapiric material is predominantly salt although shale diapirs occur. Movement may still be active on some of the diapirs at the shelf edge and beyond and could cause problems. The salt also appears to be moving horizontally toward the escarpment.

On the outer shelf and upper slope numerous salt diapirs with surface expression have living and dead reefal communities topping them.

The Mississippi/Alabama Shelf contains potential geohazards similar to the Louisiana Shelf.

1. Growth faulting extends from mid shelf to the foot of the continental slope between Horn Island and Pensacola.

2. Salt intrusions occur from DeSoto Canyon to the Mississippi Delta.

3. The Continental Slope is subject to sediment instability in the form of active mudflows, slumping, and erosional gullies.

The Mississippi Delta has a high potential for sediment instability. Rapid deposition of organic laden muds, silts, and sand tends to trap the evolving gasses which results in gas charged, underconsolidated, and by inference, unstable sediment masses. High river stages, large storms, sediment-degassing, fault movement and mud diapirism all can and do initiate downslope movement of great masses of sediment which continues to flow under the influence of gravity. There are also mud masses which flow at much lower rates for longer periods of time.

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G. Western Gulf of Mexico

The Western Gulf of Mexico planning area is situated primarily off the coast of Texas. The geologic features are similar to the Central Gulf, with known and potential hydrocarbon structures distributed throughout the area. Geologic and meteorologic conditions affecting operations are also similar to the Central Gulf.

The shoreline is principally barrier beaches backed by bays and wetlands. The shoreline is used extensively both for wildlife habitat, and recreation and tourism. However, there is also significant industrial use of the coastal area, especially in the vicinity of the Houston Ship Channel, and the oil and gas infrastructure is well developed.

The East and West Flower Garden Banks are examples of features of topographic relief along the Central and Western Gulf seafloor. Most provide substrate suitable for highly productive biological communities, but the Flower Gardens are unique in the northern Gulf of Mexico in consisting of living coral reefs. They support a population similar to that of Caribbean coral reefs. Special stipulations have been developed to protect the Flower Garden Banks and other similar resources, after several years of Department of the Interior-funded studies. These stipulations require monitoring and provide specifications for drilling field and cuttings disposal, as well as restricting the location of oil and gas operations in some cases.

Several endangered and threatened species occur in the Western Gulf planning area: critical habitat for the whooping crane; Attwater's prairie chicken; peregrine falcon; brown pelican; bald eagle; Eskimo curlew; American alligator; Houston toad; Kemp's ridley, green, leatherback, and loggerhead sea turtles; ocelet; and right, fin, and sperm whales.

1. Regional Geology

The Western Gulf of Mexico (WGOM) Planning Area includes the entire Texas shelf and slope including the deep water areas of Corpus Christi, Port Isabel, East Breaks, Alaminos Canyon, Garden Banks, and Keathley Canyon. This area is primarily an Early Cenozoic depocenter although Paleocene and Eocene strata are very deep. Sedimentation continued throughout the Cenozoic, but the sediment supply was far less than in the Central Gulf of Mexico (CGOM) Planning Area.

Structurally the WGOM has been subjected to essentially the same tectonic forces that shaped the CGOM. However, in contrast to the dominantly deltaic depositional environment of the CGOM, the WGOM is characterized by regional down-to-the-basin fault systems with rollover into the faults and linear sand reservoirs deposited in offshore bar facies. Masses of under-compacted shales have flowed into ridges, swells, and diapirs similar to the salt structures in the CGOM.

During the early Tertiary the primary supply of sediment to the Gulf of Mexico Basin came from the west down the ancestral Rio Grande and Brazos river systems. The potential for Paleocene strata occurring in the WGOM is very low because the main depositional area lies well inland from the WGOM. Onshore Eocene production comes mainly from low axial portions of embayments on the Texas Coastal plain. These sediments grade into bathyal sediments in the WGOM. Potential Eocene producing horizons are extremely deep and marginal. There is apparent production from Oligocene sediments in the WGOM at present. Studies indicate that Oligocene turbidites and deep sea fan deposits may be present in the shelf region and should be considered potentially productive. Miocene production occurs on the Texas shelf from the High Island Area to the North Padre Island Area. Lower Miocene sands in the WGOM consist mostly of regressive sands inter-fingering with marine shales and may be as much as 5,000 feet thick on the South Texas shelf. COST Wells Nos. 1 and 2 indicate that the Lower Miocene consists primarily of shale with thin sands in the area drilled. Several small deltas were formed in the Upper Miocene in the Rio Grande embayment. However, because of a narrow shelf favorable conditions for large accumulations of sand apparently did not exist. There is a perceived lack of good quality reservoir rocks in the Miocene in the southern part of the Texas shelf. Turbidity currents and submarine channels could have transported coarse and fine grained sediments into deeper waters. There may exist, therefore, a Miocene potential in the deeper waters off South Texas. The Pliocene, in general, was subjected to the same type of depositional regime as the Miocene. Pliocene production occurs in the High Island portion of the WGOM but is less productive than off Louisiana because of a lesser sediment supply. The Pliocene has a maximum thickness of about 4,000 feet in the WGOM.

The Pleistocene sequence is exemplified by large quantities of sand deposited in a deltaic environment. Although punctuated by minor transgres-sions it was dominantly a regressive period. Production extends to the southern part of the Galveston area with significant accumulations of gas and condensate in the High Island area. Although the Pleistocene off South Texas attains a thickness of about 5,000 feet near the shelf edge, it remains nonproductive.

2. Petroleum Potential

Petroleum development in the WGOM has progressed in parallel with that in the CGOM though not as rapidly. There are approximately 150 producible fields in the WGOM, 90 of them are in the Galveston and High Island areas at the northern end of the WGOM. Production extends as far south as North Padre Island where there are five fields. Exploration and discovery have, in general, progressed from north to south and eastward into deeper water.



Source rock consists chiefly of organic-rich, Cenozoic shales. Studies indicate the possibility of Oligocene reservoir rocks in deeper waters. Miocene reservoirs extend the length of the WGOM in a narrow inshore band which widens to the northeast. There are Pleistocene reservoirs in the northern part of the WGOM. Trapping mechanisms are the same as those in the CGOM except that traps associated with rollover into growth faults are more prevalent and there is less salt diapirism. Numerous anticlinal shale ridges also provide structures for traps.

3. Geohazards

Recent sedimentation on the inner shelf has been occurring at a slow rate and sediments are normally mostly consolidated and stable. On the upper continental slope three areas containing older slumps have been located at the sites of the former Rio Grande, Colorado, and Brazos River deltas. The slumping was associated with lower stands of sea level. Shallow overpressured gas occurs at many locations in the Western Gulf. Diapirism is less prevalent toward the south but there are a few banks with drowned reefal communities located atop diapiric bulges extending south along mid shelf. Faulting tends to parallel bathymetry contours and must be taken into consideration locally.

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## H. Southern California

The Southern California planning area extends northward from the United States-Mexico Provisional Maritime Boundary to the offshore extension of the county line between San Luis Obispo and Monterey Counties and surrounds six major nearshore islands. The Channel Islands off Santa Barbara form the seaward flank of the Santa Barbara Channel and Santa Catalina Island demarcates the San Pedro Channel. Promising oil and gas structures are located primarily in the Santa Barbara Channel, Santa Monica Bay, San Pedro Bay, and the Dana Point-San Diego area. The continental shelf is very irregular off Southern California, with the slope occurring generally seaward of the islands, but extending out about 150 miles in the vicinity of Tanner and Cortes Banks.

Especially productive and diverse marine communities exist in connection with shallow banks, such as Tanner and Cortes Banks, as well as in the vicinity of upwelling and of converging water masses. The Santa Barbara Channel Ecological Preserve (3/21/69) and Channel Islands National Marine Sanctuary (10/2/80) were designated to protect and preserve habitat and wildlife. A special stipulation requiring biological surveys and imposing restrictions on drill cuttings and fluids disposal and structure placement has been used in these unique areas. The islands are important breeding sites for sea birds, seals, and other pinnipeds. A significant portion of the southern sea otter range is included in the planning area; the sea otter range also extends south of the northern planning area boundary. Whales migrate through the nearshore coastal waters. Commercial fishing efforts are concentrated in Morro Bay, in the Santa Barbara Channel, and further south in the vicinity of San Diego. A biological stipulation to provide special protection to biological resources has been applied in this planning area. Requirements for training of oil and gas personnel to reduce possible conflicts with fisheries operations, and a well and pipeline stipulation to reduce obstacles to fishing gear have also been applied in this area.

The coastline of Southern California includes extensive beaches, as well as rocky shoreline. The coastal area is well developed, due to urbanization; Los Angeles to San Diego constitutes nearly a continuous urban corridor. Recreational use of Southern California's beaches and coastal facilities is extremely high. Also, extensive military activities are carried out in the Southern California planning area.

### 1. Regional Geology

The Southern California planning area has been divided into the outer basins and banks, the inner basins and banks, the Santa Barbara Channel, and the Santa Maria basin offshore. The inner and outer basins and banks areas are the offshore portion of the Peninsular Ranges Geomorphic Province. The Santa Barbara Channel is in the Transverse Ranges Province, and the Santa Maria offshore basin is part of the southern Coast Ranges Province.

The inner basins underlie the Santa Monica and San Pedro Bays which are offshore extensions of the Los Angeles basin, as well as the Santa Monica and San Pedro basins, the San Diego Trough, and the Gulf of Santa Catalina which is the offshore portion of the Capistrano Embayment. Of these, the Gulf of Santa Catalina and possibly the San Diego Trough and northern Santa Monica basin contain Paleogene and early Neogene sediments. The other basins and banks contain only middle and late Neogene sediments overlying metamorphic basement rocks. Structural features in the inner basins are primarily northwest-southeast-trending folds and faults.



The outer basins include the Velero, Long, East Cortes, West Cortes, Tanner, Patton, San Nicolas, Santa Cruz, San Clemente, and Catalina basins. Paleogene and Late Cretaceous sandstones and shales overlie metamorphic basement rocks on the Santa Rosa - Cortes Ridge and in the Velero, Long, East and West Cortes, San Nicolas, and Santa Cruz basins. These rocks are in turn overlain by Neogene sediments in the basins. Neogene sediments overlie basement rocks elsewhere on the outer basins and banks. Structural features are primarily folds and faults which trend northwest-southeast.

Sediments in the Santa Barbara Channel include a thick section of pre-Neogene marine and nonmarine conglomerates, sandstones and shales which are truncated to the west by an erosional unconformity. These older sediments are covered by Neogene sandstones, shales and fine-grained siliceous rocks which thicken toward the northeast. Structural features in the Santa Barbara Channel are faults and asymmetric folds which trend east-west.

Throughout much of the Santa Maria offshore basin, middle and late Neogene sediments overlie Cretaceous and older sediments and metamorphic rocks. Remnants of early Paleogene sediments have been preserved beneath the Neogene sediments in low areas around the periphery of the basin. Structural alignment of the folds and faults is generally northwest-southeast.

### 2. Petroleum Potential

The history of offshore exploration in the Southern California planning area can be divided into three phases. The first phase was carried out under leases from littoral landowners, and started in 1896 offshore of Summerland in Santa Barbara County. The second phase began in 1921, with State legislation which permitted leasing of State tide and submerged lands, followed by further legislation in 1938, 1955, and 1957. Exploratory drilling on State tidelands as a consequence of this legislation resulted in the discovery of six fields prior to 1938 and twelve additional fields from 1943 to 1968. In addition, four fields have been discovered on tide and submerged lands granted to local governments. During this second phase many deep and shallow core holes were drilled offshore. The third phase began with the first Federal OCS oil and gas lease sale on the Pacific Coast which was held on May 14, 1963, and included tracts on the California OCS between Point Conception and the Oregon border. No discoveries were recorded from this sale. The first OCS lease sale of tracts south of Point Conception was held on December 15, 1966, and consisted of one tract subject to State drainage in the Santa Barbara Channel. Since then eight lease sales have been held in the Southern California planning area.

Two COST wells were completed in 1975 and 1978 on of Cortes Ridge and west of Point Conception, respectively. As of July 1, 1986, 279 exploratory wells have been completed.

The primary reservoirs in the Santa Monica and San Pedro Bays, and the northeastern Santa Barbara Channel are sandstone beds of middle and early Pliocene and late Miocene ages as is the case in their onshore counterparts, the Los Angeles and Ventura basins. In the Dana Point-San Diego area, Neogene and Paleogene sandstones are potential reservoirs. Miocene sandstones and fractured fine-grained Monterey siliceous and calcareous reservoirs are the primary targets in most of the other inner and outer basins, in the southern and western Santa Barbara Channel and in the Santa Maria basin. Paleogene sandstone reservoirs are additional targets in the Channel and in the outer basins. While Miocene shales, especially the highly organic shales included in the Monterey Formation, are the major source rocks in Southern California, Pliocene and Paleogene shales may also be source rocks.

At the end of June 1984, remaining recoverable reserves of oil and gas on the southern California OCS were estimated to be 1,205 million barrels of oil and 2,198 billion cubic feet of gas. These reserves are contained in 23 fields, of which two are gas fields, thirteen are oil fields, and eight are combination oil and gas fields. At the end of 1984, seven OCS fields were on production, six in the Santa Barbara Channel and one in San Pedro Bay.

3. Geohazards

Potential geologic hazards that could inhibit the safe exploration and development of oil and gas resources on the southern California OCS include the high incidence of seismicity, active faults, mass transport of sediments, and steep slopes and canyon walls. Buried channels, hydrocarbon seeps, and shallow gas accumulations constitute less serious geologic constraints.

Southern California is a portion of the Pacific/North American plate boundary within the Circum-Pacific volcanic and seismic belt, which has been active throughout Cenozoic time and has been highly active in Quaternary time. The southern California OCS has a history of significant seismic activity.

Active faults are potentially hazardous because of possible ground rupture and shaking, and they may act as conduits for pressurized subsurface fluids to reach the surface. Inactive faults may be reactivated by injection or withdrawals on fluids. Active faults are present throughout offshore California. Active faulting and seismicity present a potential hazard for offshore operations.

Mass transport, the gravity-induced downslope movement of unconsolidated to semiconsolidated sediments, may cause loss of support for structures and pipelines. Such deposits are common along the northern slope of the Santa Barbara Channel and cover more than 90 percent of the central channel. They are also common on slopes in the inner and outer basins and banks. Four zones of mass transport deposits have been identified in the southern Santa Maria offshore basin. Due to the potential for loss of sea floor support of structures, the use of jack-up rigs in areas of mass transport zones is not prudent. However the substitue use of a semisubmersible or a drillship renders this hazard benign.

Slopes of greater than 10° are classified as steep. These slopes are common along the flanks of ridges and within submarine canyons of the Southern California planning area.

High-pressure shallow gas zones can cause blowouts if penetrated without proper drilling and casing procedures, and may also contribute to instability by lowering the shear strength of sediments. Shallow gas zones are confined almost exclusively to Pliocene and Pleistocene rocks along the shelf break at the northern edge of the Santa Barbara Channel, and along the coastal shelf from Palos Verdes to Mexico. Shallow gas is commonly associated with faulting and occurs along the flanks and crests of anticlinal structures throughout the Southern California planning area.



Abnormally pressured shallow gas zones are uncommon on the Pacific OCS due to the presence of unconsolidated to semiconsolidated near-surface sediments and their characteristic "bleeding off" of in situ biogenic gas. Most Pacific OCS shallow gas zones are at ambient pressures and do not pose a problem to drilling activities.

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I. Central California

The planning area extends from the offshore extension of the county line between San Luis Obispo and Monterey Counties to the offshore extension of the county line between Sonoma and Mendocino Counties. The continental shelf off the Central California planning area ranges from less than one mile to about 30 miles wide. Geologic hazards include seismic activity, faulting, slope instability, and turbidity currents. Oceanographic hazards include occasional high sea states.

The Farallon Islands off San Francisco, surrounding banks, and other rocky banks are habitats of special concern. The Point Reyes-Farallon Islands National Marine Sanctuary was designated (1/16/81) "to protect and to preserve the marine birds and mammals, their habitats, and other material resources from those activities which pose significant threats." These areas, associated with the seaward edge of the continental shelf, provide substrate for a rich assemblage of attached organisms, which in turn attract fish. The Farallon Islands and other islands, as well as shoreline cliffs and offshore rocks, provide important breeding habitats for seabirds and marine mammals--seals, southern sea otters, etc. Whales migrate within sight of shore along the California coast. Special stipulations to protect biological resources and to require fisheries training for oil and gas personnel have been developed in the past for use in this area similar to those described for Southern California.

The rocky coastline, as well as ownership patterns, have limited industrial development along the coast. With the exception of San Francisco, only small ports exist which primarily serve fishermen.

1. Regional Geology

The Central California planning area includes the northern portion of the Santa Maria offshore basin, (sometimes referred to as the "Partington basin"), the Ano Nuevo (Outer Santa Cruz) basin, the La Honda (Inner Santa Cruz) basin, and the Bodega basin.

Available geologic evidence indicates that the present distribution of Paleogene and older sediments in the basins varies considerably throughout the planning area. In the Partington basin there is no evidence that Paleogene or older sediments are present, while in the Ano Nuevo basin to the northwest, early Neogene sediments and volcanics rest on Cretaceous rocks. Paleogene sandstones and shales are present in the La Honda basin onshore but late Paleogene sediments are absent due to Oligocene erosion in the Bodega basin which is the northwest extension of the La Honda basin.

In contrast to Paleogene sediments, Neogene sediments are widely distributed over the basins included in the planning area. In the Partington basin, the Monterey Formation apparently rests on basement rocks, while in the Ano Nuevo basin a thick section of Monterey rocks overlies early Neogene sediments and volcanics. Early to late Neogene sediments and volcanics are present throughout the La Honda and Bodega basins, however, late Miocene erosion removed much of the Monterey Formation in some portions of the Bodega basin. Organic rich, fine-grained calcareous and siliceous rocks of the Monterey Formation are present in all the basins located within the planning area and under certain diagenetic conditions may provide the major source of hydrocarbons as well as become the primary reservoir in traps throughout the planning area. In the basins, rocks of the Monterey Formation are overlain by varying thicknesses of late Neogene mudstone, shale, and minor amounts of sandstone.

The planning area is in the offshore portion of the Coast Ranges Geomorphic Province, and structural folds and faults trend northwest-southeast approximately parallel to the basin trends.

2. Petroleum Potential

The history of exploration in offshore Central California began with seismic surveys and dart sampling conducted in anticipation of the first Pacific OCS oil and gas lease sale which was held on May 14, 1963. Tracts were leased in the Ano Nuevo and Bodega basins, and while 12 exploratory wells were drilled on leased tracts, no discoveries were announced and all leases were relinquished by June 14, 1968. No other OCS sales have been held in the Central California planning area.

While the primary source and reservoir rocks in the four basins within the planning area are in the Monterey Formation of middle and late Miocene age, additional potential hydrocarbon sources and reservoirs exist in the shales and sandstones of the younger and older rocks of the sedimentary section. The basins are considered to be oil-prone.



The offshore Santa Maria basin may be the near character equivalent of the onshore Santa Maria basin. In onshore areas, petroleum has been produced primarily from fractured reservoirs in the fine-grained Monterey Formation, although there has also been some production from sandstone reservoirs. The onshore Santa Maria basin is one of the most productive oil bearing regions in California.

Some of the earliest oil and gas production in California (circa 1880), came from fields in the onshore portion of the La Honda basin, where oil ranging from 16°-45° API gravity was produced from Paleogene sediments as well as early and late Neogene sandstone reservoirs. Some of these oil-saturated sandstones are exposed in sea cliffs at Double Point (southeast of Point Reyes) and in onshore canyons northwest of Santa Cruz.

Ten wells were drilled in the Bodega basin and two in the Ano Nuevo basin on leases issued in the 1964 OCS lease sale. In both Ano Nuevo wells, drill cuttings throughout the nearly 3,000 feet of Monterey Formation were coated with free tarry oil, but no drillstem tests were run. Oil shows were encountered in six of the Bodega basin wells, one of which was tested, resulting in the recovery of only drilling mud and water.

3. Geohazards

Potential geologic hazards that could affect the safe exploration and development of oil and gas resources in the Central California planning area include a high incidence of seismicity, active faults, mass transport of sediments, and steep slopes and canyon walls. Buried channels, hydrocarbon seeps, and shallow gas accumulations constitute less serious geologic constraints. The Central California planning area is located within the circum-Pacific volcanic and seismic belt, which has been active throughout middle and late Cenozoic time. Earthquakes of magnitude 5 and greater have been recorded from Monterey to San Francisco. Offshore basins in Central California lie adjacent to one or more seismically active faults and may be expected to experience seismically-induced ground motion. The San Andreas fault extends northwestward onshore in central California, intercepting the coast at San Francisco and Bodega Bay. The San Gregorio-Palo Colorado-Seal Cove fault zone along the Central California coast is considered potentially active.

Evidence of slope failure and the mass transport of surficial sediments is common on the continental slope west of Bodega basin and in the submarine canyons located in the planning area. Moderate (5-10°) to steep slopes (greater than 10°) occur along the continental slope off central California, on the flanks of the major bedrock highs rimming the basins, and locally within the many submarine canyon systems. Buried channels are also found in submarine canyon systems and fans.

In the Central California planning area, high pressure shallow gas zones occur in deformed sediments associated with fault zones and anticlines. Near-surface gaseous sediments at normal pressures occur in undeformed seaward-dipping unconsolidated to semi-consolidated sediments at the shelf break.

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J. Northern California

The Northern California planning area includes the area north of the previously described Central California planning area and extends northward to the Oregon border. It includes the two northernmost geologic basins off California: Point Arena and Eel River.

The continental shelf in the area is narrow, ranging from less than one mile in width to about 30 miles. Geologic hazards include seismic activity, faulting, slope instability, piercement structures and turbidity currents. Oceangraphic hazards include occasional high seas.

Shoreline cliffs and offshore rocks, provide an important breeding habitat for seabirds and marine mammals, namely seals. Whales migrate within sight of shore along the California coast. Habitats of special concern in the Northern California planning area include the Georges Reef near Crescent City and Tolo Bank south of the Mendocino Peninsula.

The rocky coastline, as well as ownership patterns, have limited industrial development along the coast.

1. Regional Geology

The Northern California planning area includes the Point Arena and Eel River offshore basins: These basins are separated by the Mendocino fracture zone.

The Point Arena basin is bounded on the east by the San Andreas fault, on the west by the Oconostota uplift, on the south by the Gualala uplift, and on the north by the Mendocino fracture zone. Although rocks of Paleogene age are present in the basin, the younger sediments have been removed by erosion during uplift in late Paleogene time. These older rocks are overlain by a thick section of Neogene rocks which ranges from earliest Miocene through Quaternary Age.

The Eel River basin offshore extends northward from the Mendocino Fracture Zone to Cape Blanco in southern Oregon. Sediments in the basin overlying metamorphic "Franciscan" basement rocks include rocks of Cretaceous and early



Paleogene age which are separated from late Neogene age rocks of the "Wildcat Group" by a major unconformity. Gas is produced in the onshore Eel River basin from thin turbidite sandstone beds of Pliocene age.

The Northern California planning area is in the offshore portion of the Coast Ranges Geomorphic Province and structural folds and faults trend northwest-southeast to north-south, parallel to the alignment of the basin axes.

2. Petroleum Potential

To date, the only Pacific OCS oil and gas lease sale in the Northern California Planning Area was held on May 14, 1963, and included tracts in the Point Arena and Eel River basins. Four exploratory wells were drilled in the Eel River basin and three in the Point Arena basin on tracts leased in this sale. However, no discoveries were announced and all leases were relinquished. No OCS lease sales have been held in the Northern California planning area since then.

The primary source and reservoir rocks in the Point Arena basin are in the Monterey Formation of middle and late Miocene age. Additional potential hydrocarbon sources and reservoirs exist in the shales and sandstone above and below the Monterey Formation. Oil saturated sandstone beds in the Monterey Formation outcrop in the sea cliff at Arena Cove, and 29° API gravity oil was recovered in a wireline test of the Monterey Formation in an offshore well in which 90 percent of the drill cuttings were coated with free tarry oil.

Commercial gas is produced from thin Pliocene turbidite sandstone reservoirs in two fields in the onshore Eel River basin. Four dry exploratory wells were drilled along the edge of the basin offshore. Onshore, a minor amount (350 bbls) of high gravity (46° API) oil was produced from Cretaceous rocks near Petrolia, 10 miles south of the Eel River basin, and oil and gas seeps occur in Cretaceous and Pliocene sediments along the southern margin of the basin.

3. Geohazards

Potential geologic hazards that could affect the safe exploration and development of oil and gas resources in the Northern California planning area incude a high incidence of seismicity, active faults, mass transport of sediments, and steep slopes and canyon walls. Buried channels, hydrocarbon seeps, and shallow gas accumulations constitute less serious geologic constraints. Northern California is within the circum-Pacific volcanic and seismic belt that has been active throughout middle and late Cenozoic time.

The planning area is adjacent to seismically active faults and may be expected to experience seismically-induced ground motion. The San Andreas fault and the Mendocino fracture zone border the Point Arena basin on the east and north respectively, and the Mendocino fracture zone borders the Eel River basin on the south.

Evidence of slope failure and the mass transport of surficial sediments is common on the continental shelf and slope of northern California. Several large mass-transport deposits have been mapped in the offshore Eel River basin, and along the continental slope near Point Arena.

Moderate (5-10°) to steep slopes (greater than 10°) occur along the continental slope off northern California and on the Gorda Escarpment of the Mendocino fracture zone, as well as within the many submarine canyon systems located within the planning area. Buried channels also are found in submarine canyon systems and fans.

In the Northern California Planning Area, high pressure shallow gas accumulations occur in deformed sediments associated with fault zones and anticlines and in undeformed seaward-dipping unconsolidated to semi-consolidated sediments at the shelf break. Geopressured shales occur at depth in the offshore Eel River basin.

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K. Washington-Oregon

The Washington-Oregon planning area extends from the California-Oregon border to the U.S.-Canada border. The continental shelf is relatively narrow, ranging from 8 miles to 42 miles in width.



The Pacific Northwest coast is characterized by large inland bays and estuaries (e.g. Puget Sound and the Columbia River). These bays and estuaries are of considerable importance to the region's fish and wildlife resources serving as nursery and spawning areas for several important fisheries which include salmon, crabs, oysters, shrimp, and a few other fin fish. Offshore rocks, estuaries and extensive wetland areas also provide ideal habitats for a large and varied marine mammal and bird population.

The Washington and Oregon coastlines are primarily classified as undeveloped or designated for recreational use, with a few scattered small towns near bays and rivers. These coastal towns are primarily dependent on agriculture, fisheries, forest activities, or recreation. Commercial fishing is an important economic activity both regionally and nationally.

1. Regional Geology

The Washington-Oregon planning area includes the northernmost part of the Eel River basin and an elongate trough in which as much as 25,000 ft. of Tertiary sedimentary and volcanic rock has accumulated. This trough extends southward from Vancouver Island approximately 400 miles to the vicinity of the Klamath Mountains and from the base of the continental slope eastward to the western edge of the Cascade Range.

The three major Tertiary depositional cycles present in California are also present in the Washington-Oregon planning area. They include the Paleogene cycle comprising rocks of Oligocene and Eocene age, the early Neogene cycle consisting of rocks of early and middle Miocene age, and the late Neogene cycle made up of late Miocene and Pliocene rocks.

In the Eel River basin, which extends northward from offshore Cape Mendocino in California to offshore Cape Blanco in Oregon, the Paleogene cycle is deeply eroded and is overlain by late Neogene deposits, with early Neogene rocks not identified. In the Coos Bay area north of Cape Blanco, early Neogene rocks and late Neogene rocks overlie a nearly complete Paleogene section. A similar condition exists offshore of Willapa, Washington. However, here the Paleogene and early Neogene section consists of a melange of Oligocene, Eocene and early Neogene sediments called the "Hoh Rocks" or "Hoh River Beds."

Throughout most of the trough, volcanic rocks of early Eocene age constitute economic basement. The only major outcrops of early Neogene rocks north of the Mendocino Escarpment occur in Oregon near Newport and Astoria. These outcrops include the Astoria, Nye, and Yaquina Formations which are equivalent in age to the Monterey, Rincon, and Vaqueros Formations present in southern and central California. The rocks found in Oregon lack the high organic content of the rich source rocks of California. These formations are composed of sandstone, sandy siltstone, and mudstone beds. Many of the sandstone beds in the Washington-Oregon and Northern California planning area OCS are turbidites.

Snavely and others (1977) state that fold axes on the outer part of the continential shelf of Oregon and Washington trend roughly north-south, parallel to the base of the slope. On the inner shelf however, the trends of the folds vary from northwest to northeast. Some of the folds have highly deformed shale/siltstone cores. High-angle reverse faults are associated with the folding.

### 2. Petroleum Potential

A Washington-Oregon OCS lease sale was held on October 1, 1964. Offered in the sale were 149 tracts off the coast of Oregon and 47 tracts off the State of Washington. The sale resulted in the leasing of 74 tracts off the coast of Oregon and 27 tracts off the coast of Washington. On these leases, 8 exploratory wells (7 original holes and 1 redrill) were drilled off Oregon and 4 wells (3 original holes and 1 redrill) were drilled off Washington. All of the wells except one encountered abnormally high subsurface pressures while drilling. Indications of oil and gas were found in several of the wildcats, but none were considered to be commercial at the time. No OCS lease sales have been held in the Oregon-Washington planning area since the initial sale.

The siliceous rocks common in the Monterey Formation in California, which often are highly-fractured source and reservoir beds, are absent in the Washington-Oregon Planning Area. However, other potential source and reservoir rocks are present. The Nye Formation of Miocene age, the Alsea Formation of Oligocene age, and the Bastendorf Formation of late Eocene age contain organic shales of some richness.

Volcanic activity was prevalent in the area throughout much of Tertiary time. As a consequence, many of the sediments are tuffaceous. Tuffaceous rocks, in general, are poor reservoirs because they contain clay minerals which tend to fill the pore space, diminishing the effective porosity and permeability of the rocks.

At Coos Bay, the Coaledo Formation includes coal beds as well as sandstone beds from which non-commercial amounts of gas have been produced. The gas in the Mist field in northwestern Oregon is produced from Eocene sandstone reservoirs and a minor amount of oil was produced from "Hoh Rocks" from 1957 to 1962 in the Ocean City oil field in southwestern Washington.

### 3. Geohazards

Most of the recently recorded major earthquakes in the Washington-Oregon planning area have been in Puget Sound. However, based on past experiences, major earthquakes can be expected for the entire planning area. The scarcity of geological and geophysical data make it impossible to completely assess the potential geologic hazards in the Washington-Oregon planning area. The following discussion is summarized from Snavely and others (1977). Potential geohazards that could affect the safe exploration and development of oil and gas resources in offshore Washington and Oregon include a high incidence of seismic activity and related seismically-induced geohazards; mass-transport of sediment; and sea-floor warping, subsurface overpressured zones, and shallow gas accumulations associated with diapiric intrusions.

The intense tectonic activity recorded in the Upper Cretaceous and Quaternary rocks and the earthquake history of the region indicate that the Washington-Oregon OCS continues to be seismically active. Seismically-induced geohazards include ground-shaking, fault displacement, ground rupture, tectonic warping and earthquake-induced mass-transport. Numerous faults that offset upper Pleistocene to recent deposits have been mapped in the coastal areas of Oregon and Washington.



Water-saturated or highly sheared Tertiary sedimentary rocks (Melange) and semi-consolidated Quaternary deposits which border much of the Washington coast are subject to loss of bearing strength or slope failure either under the influence of gravity or due to seismic groundshaking.

Areas of moderate to relatively steep slopes contain numerous slump features. These are most prevalent on steep slopes with thick sediment accumulations such as the continental shelf-slope break and on the flanks of submarine canyons that incise into the shelf. Interbeds of volcanic ash may be continuous for more than 18 miles offshore Washington and Oregon. These ash beds provide planes of weakness that may facilitate mass transport. The ash devitrifies readily in the marine environment which reduces the bearing strength of the sediments.

There are an estimated 50-100 diapiric intrusions on the Washington-Oregon OCS. These shale/siltstone piercement structures often warp and occasionally offset sea-floor sediments. The sediments included in the structures are probably overpressured and gas pockets may exist at shallow depths. Gas seeps are found along the flanks of the diapirs. Areas of unstable, poorly-consolidated deposits may exist along the flanks of the piercement structures.

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## L. Gulf of Alaska

The Gulf of Alaska planning area includes part of a 900-mile long structural feature paralleling the southern Alaska coast which may be hydrocarbon productive. Geohazards include active faulting, high seismicity, gas charged sediments, and submarine slides. While ice free year-round, icing of superstructures, and extreme conditions, including wind and wave height, can present hazardous operating conditions.

The Gulf of Alaska coastal area is characterized by numerous bays and islands. Prince William Sound and the Copper River delta are major geographical features as well as highly biologically productive areas. Nearshore waters and rivers of the area are important nursery areas and spawning grounds for shrimp and crab, and for salmon, respectively. The islands and other nearshore areas are extremely productive breeding grounds for seabirds and for marine mammals. Large seasonal concentrations of birds and mammals also depend on the area for foraging or migration staging. Seven endangered or threatened whale species and four bird species inhabit the area seasonally.

The coastline is virtually undeveloped, with only a handful of coastal towns or villages. However, the port of Valdez pipeline terminal is located within the planning area. The fishing industry is extremely productive in the Gulf of Alaska, especially for crab, shrimp, salmon and a number of species of groundfish. Fishing is also important as a subsistence activity for the native population. Stipulations have been used in the Gulf of Alaska in the past to reduce potential conflicts between oil and gas operations and commercial fishing and subsistence activities. These have included a stipulation regarding design of wells and pipelines and a stipulation requiring environmental training for oil and gas personnel.

### 1. Regional Geology

The stratigraphy of the Gulf of Alaska is dominated by four formations. The Mesozoic Yakutat Formation is believed to be the top of economic and acoustic basement in the Fairweather Grounds from Cross Sound to Dixon Entrance. Northeast of Cross Sound, the Yakutat Formation has a thick covering of Tertiary sediments. Above this formation is the middle Tertiary Kulthieth Formation which is seen in two offshore wells. It has good reservoir and source rocks but wells have only reached it on the eastern and western flanks of the Bering Trough of the central Gulf of Alaska. The late Eocene to early Miocene Poul Creek Formation above the Kulthieth represents a fair source rock. It is seen both onshore and in five offshore wells where it is a thick shale. The Upper Miocene to Pleistocene Yakataga Formation is predominantly glacially derived sediments which have immature source rocks and poor reservoir rocks. This is the dominant section that was found by the ten unsuccessful wells drilled in the Bering Trough.

### 2. Petroleum Potential

Onshore oil and gas exploration began in 1902 from Kayak Island to Dry Bay. Offshore exploration began in 1969 near Middleton Island and continued until 1982. Twelve exploration wells and one COST well were drilled with no discovery of an oil or gas reservoir.

The only producing field along the Gulf of Alaska, Katalla, produced oil along a fault zone in the onshore Poul Creek Formation. Offshore these rocks are a massive shale and a potential source for petroleum but not a reservoir. In the five offshore wells that encounter the Poul Creek Formation, all have immature source rocks and the total organic carbon is less than one percent and usually 0.5 percent. The Kulthieth Formation may be a good reservoir and possibly another source for petroleum but this formation was only found in two offshore wells. The source rocks are more prone to have gas than oil. Most of the exploration wells have been drilled through the Yakataga Formation which is a very poor source rock and a fair reservoir rock.

The potential traps were mapped on the Yakataga and Kulthieth Formations. These traps are large anticlines which are asymmetric, elongate and doubly plunging, faulted anticlines and traps against major faults. Nine of these traps have been drilled with no discoveries of oil or gas.

### 3. Geohazards

Sea floor hazards in the Gulf of Alaska include faults, gas-charged sediments, submarine slides and buried channels. Surface and near-surface faults that show signs of recent activity occur in eight general areas: (1) Pamplona Ridge - Ice Bay zone, (2) Fairweather Ground shelf - edge structural high, (3) shelf-edge near Alsek Sea Valley, (4) seaward extension of the Fairweather-fault system, (5) south of Cape Yakatagu, (6) on or adjacent to the Kayak Island platform, (7) on Tarr Bank, and (8) near Middleton Island.



Gas-charged sediments occur throughout the Gulf of Alaska generally covering small areas (less than 10 $km^2$). One exception is a nearshore area between the Dangerous and Alsek Rivers that encompasses over 200 $km^2$. Studies of the gas-charged sediment indicate that the source of the gas is the bacterial breakdown of organic material deposited in the rapidly accumulating Holocene sediment.

Submarine slides and slumps are prevalent on the walls of sea valleys, along the continental slope, and in nearshore zones, especially off the mouths of rivers. Sediment movement in the Gulf of Alaska can be triggered by gravity or earthquakes in areas with thick, unconsolidated sediment on moderate to steep slope angles. Most of the buried channels are concentrated in nearshore locations offshore of existing rivers and glaciers. The channels vary widely in size and most appear to have been cut into Pleistocene and older glacial sediment. Other hazards include tsunamis and seiches.

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## M. Kodiak

This planning area is offshore Kodiak Island and includes the western central portion of the Gulf of Alaska. The Kodiak planning area contains the Kodiak Tertiary Basins. Geologic, weather and sea conditions are similar to the Gulf of Alaska. The area has a high potential for seismic events and volcanism, and contains shallow gas.

Kodiak Island, surrounding islands and Portlock and Albatross Banks host some of the Gulf of Alaska's greatest concentrations of bird and sea mammal nesting sites, foraging areas, and shellfish nursery areas. Seven endangered whale species and four bird species inhabit the area seasonally. The western portion of the Gulf of Alaska supports a large part of the Gulf fishery. Kodiak's port services the Gulf commercial fishery--Kodiak has been among the top 10 fishing ports (for pounds landed) in the U.S. in the last 10 years. The island is also seeking to expand its fish processing industry especially for bottom fish species.

1. Regional Geology

The tectonic setting of the Kodiak shelf is within an arc-trench gap which separates the active Alaska-Aleutian magmatic arc on the northwest from the Aleutian trench to the southeast. Since early Cenozoic time, Pacific plate lithosphere has migrated northward relative to mainland Alaska and the North American continent. This differential movement is accommodated at the Aleutian trench where Pacific lithosphere is subducted beneath the Alaskan continental margin. The tectonostratigraphic evolution of the Kodiak shelf fore-arc basin has been strongly controlled by the nature and episodicity of interaction between the two major crustal plates at this zone convergence.

The Kodiak shelf is underlain by two major tectonostratigraphic units. Acoustic basement beneath the shelf is composed of a highly deformed assemblage of flysch and mafic volcanic rocks ranging in age from Paleocene or older to Oligocene. This basement complex is unconformably overlain by up to 25,000 feet of gently-deformed shelf sediments ranging in age from Miocene to Recent. Available seismic data is only capable of resolving coherent, mappable reflectors within or at the base of the younger shelf sequence.

2. Petroleum Potential

Six COST wells were drilled during 1976 and 1977 on the Kodiak shelf. In addition, in 1971 the Deep Sea Drilling Project drilled two holes on the continental slope off Kodiak Island.

Source rock potential for most rocks underlying Kodiak shelf is poor. Most strata contain less than 0.5 percent total organic carbon (TOC) rendering them marginal potential sources at best. Data from the Middleton Island well, 200 km along strike to the northwest, suggest that isolated source beds may be present in strata scattered throughout the Tertiary section that contain sufficient organic carbon to make them good potential source beds. Structured Kerogen predominates in these source beds which, due to the low H/C ratio, indicates that these rocks would tend to generate gas rather than oil. Significant exceptions to this pattern are Eocene beds that contain primarily amorphous Kerogen. These beds, which have an aggregate thickness of 385 feet, could generate oil rather than gas. Thermal maturity for rocks underlying Kodiak shelf is low. Beneath Kodiak shelf, oil generation, if present is in the early generation stage and thermogenic gas generation has not yet commenced.

Folds and faults which deform the shelf sequence trend predominately northeast parallel to the axis of the Aleutian trench. These structures are superimposed on larger-scale transverse uplifts which strike orthogonal to the main arc trend and segment the shelf into discrete, equidimensional basins. Recognized hydrocarbon traps underlying the Kodiak shelf are simple structures limited to Neogene strata and are found throughout the Kodiak shelf. Trap types include simple folds, fault closures, and unconformity truncations. No regional seals are known to be present but interbedded shales which enclose reservoir sands and which are capable of acting as local seals may be reasonably presumed to be present in all structures.

Reservoir rocks are unlikely to be present in Paleogene strata due to both their original lithology and subsequent degree of alteration. However, some reservoir rocks with reservoir-quality porosity and permeability are inferred to be present in Neogene strata. Samples obtained from the Paleocene Ghost Rocks



Formation and the Eocene and Oligocene Sitkalidak Formation have both low porosity and low permeability (1-3 percent and less than 0.1 millidarcy, respectively). Direct measurements of the porosity and permeability of Miocene and younger sandstones exposed onshore are not available, although thin Pliocene sands in the Middleton well range up to 16 percent in porosity. Lithologic descriptions of outcrops on Kodiak and surrounding islands reveal that in general, sediment tends to increase in compositional maturity and porosity and permeability with decreasing age throughout the sampled part of the Neogene.

3. Geohazards

Geological aspects of the Kodiak shelf which pose potential hazards to petroleum-related activities include large-magnitude seismic events, active faults, mobile seafloor sediment, shallow gas accumlations, and volcanic activity. Shallow faults and gasification of near-surface sediments offer potential problems to both exploration drilling and production operations. The remaining geohazards are episodic and chiefly impact long-term operations such as production development. Other hazards include superstructure icing, tsunamis, and seiches.

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N. Shumagin

This planning area is situated south of the Alaskan Peninsula and Unimak Island. It includes two basins identified as possibly containing hydrocarbons--the Shumagin Basin, between Semidi and Shumagin Islands, and the Sanak Basin, northeast of the Sanak Islands. Geohazards include faulting, volcanism and earthquakes.

The south side of the Alaska Peninsula is characterized by rocky cliffs and beaches and is virtually undeveloped. Human use of the coastal area is confined to subsistence uses. Offshore, the primary human use is commercial fisheries. Additionally, the coastal waters of this area are important for producing shrimp, crab, and bottom fish species.

As in the Kodiak vicinity, the islands in the Shumagin planning area also support high concentrations of nesting bird colonies and pinniped habitat.

1. Regional Geology

The tectonic setting of the Shumagin Shelf is within an arc-trench gap which separates the active Alaskan Aleutian magmatic arc on the northwest from the Aleutian trench to the southeast. Since early Cenozoic time, the Pacific plate lithosphere has migrated northward relative to mainland Alaska and the North American Continent. This differential movement has been accommodated at the Aleutian trench where Pacific lithosphere is subducted beneath the Alaskan continental margin. The techtonostratigraphic evolution of the Shumagin Forearc Basins has been strongly controlled by the interaction of these two major crustal plates at this zone of convergence.

The Alaskan Peninsula northwest of the Shumagin Shelf contains a Mesozoic sequence of volcanoclastic sandstone and siltstone, in addition to a sequence of arkosic sandstone and conglomerates. Tertiary sedimentary rocks contain a high percentage of andesitic and basaltic rock fragments.

Southeast of the shelf-type Mesozoic sequence of the Alaskan Peninsula, is the Shumagin Formation of Late Cretaceous age found on Sanak and the outer Shumagim Islands. The islands are an uplifed portion of the Shumagin shelf which exposes an ancient deep water flysch sequence of interbedded sandstone and mudstone which has been intruded by granitic plutons.

Geophysical data accumulated and tied into the adjacent geologic and geophysical interpretation of the Kodiak Shelf indicate two major tectonostratigraphic units which underlie the Shumagin Shelf. Acoustic basement consists of highly deformed and disrupted sedimentary sequence ranging in age from Paleocene or older to Oligocene. Filling of the basins which rest upon acoustic basement is up to 25,000 feet of gently deformed shelf and upper slope sediments ranging in age from Miocene to recent.

Folds and faults which deform the sequence of sediments on the shelf predominantly follow the axis of the Aleutian trench. The rocks of the Kenai Peninsula, the Kodiak Islands, and the Shumagin Islands generally strike northeast, while rocks on the Sanak Islands strike northwest toward Unimak Island and the margin of the Bering Sea Shelf beyond.

2. Petroleum Potential

The Shumagin planning area is a frontier region without well data. The closest oil and gas fields are located within Cook Inlet, approximately 700 km to the northeast.

Preliminary observations of geophysical data indicate that both structural and stratigraphic traps located offshore appear capable of entrapping hydrocarbons. Verification of closure, in most cases, has been tentative, due to the low density of the geophysical data.

Structures are considered most prospective where broad anticlinal folds and stratigraphic terminations flank basins within which adequate levels of thermal maturation have been reached for generation and expulsion of hydrocarbons. To date there has been no geologic data on the Shumagin Shelf to verify the reliability of either a sufficient source or presence of a porous reservoir sequence. Geologic analysis of potential liquid hydrocarbon sources and potential reservoirs from the adjacent Kodiak Shelf suggest a low to moderate probability for the occurrence of commercial accumulations within the Shumagin Planning Area.



3. Geohazards

High resolution data shot on the Shumagin Shelf by the USGS has not been interpreted at present. The Shumagin Shelf, located within the same tectonic belt as the Kodiak Shelf, probably contains similar petroleum engineering constraints. The Kodiak Shelf is associated with large magnitude seismic events, active faults, mobile seafloor sediment, shallow gas accumulations, and volcanic activity. When the Shumagin gap ruptures, the energy release could range as high as 9 Richter magnitude and produce a broad spectrum of frequencies. Other hazards include tsunamis and seiches.

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0. Cook Inlet

The Cook Inlet Planning area extends from the State of Alaska waters to southwest Shelikof Straits. In addition to the seismic risk common to southern Alaskan planning areas, Cook Inlet experiences swift tidal currents and ice floes for about 4 months of the year. Geohazards are principally scour and fill, sediment slumping, volcanism and strong motion earthquakes.

The Inlet is a tidal estuary and is bordered mostly by beaches and tidal flats, with some rocky shores. It is an important area of waterfowl and shorebird nesting, especially Kachemak Bay. Shrimp, salmon and crab are commercially fished. The area also supports a good sports fishery. Three endangered whale species inhabit the area.

Anchorage is situated at the northern end of Cook Inlet and is the financial, population and service center of Alaska. The Kenai Peninsula is also relatively well populated, and supports a modest oil and gas industry, including infrastructure for offshore development. In past lease sales, stipulations similar to those described for the Gulf of Alaska have provided for protection of fishing activities.

1. Regional Geology

Rocks of lower Cook Inlet are part of a belt of Mesozoic and Cenozoic sedimentary rocks that underlie upper Cook Inlet on the northeast and the Alaska Peninsula and the Shelikof Strait on the southwest. Locally along this belt, marine Mesozoic rocks may be more than 11,000 m thick, and continental Cenozoic rocks are as much as 7,600 m thick. Four major northeast-trending geologic features that flank Cook Inlet are the Alaska-Aleutian Range batholith and the Bruin Bay fault on the northwest side, and the Border Ranges fault and the terrane of undifferentiated Mesozoic and Cenozoic rocks on the southeast side.

## 2. Petroleum Potential

Three Federal lease sales, Sale CI, 60, and RS-2 have been held in the lower Cook Inlet/Shelikof area. One COST well and 13 exploratory wells have been completed to date. Two of these wells had significant oil shows but both wells were tested as being non-commercial. These wells tested many of the major structures in lower Cook Inlet. Commercial oil and gas fields are located both onshore and offshore in upper Cook Inlet north of Kalgin Island. All of the leases from Sale CI have expired and there are three active leases (as of July 1986) from Sale 60.

Generalized lithologic characteristics have been compiled from the eight exploration wells drilled as of November 1984, and the Continental Offshore Stratigraphic Test well drilled in lower Cook Inlet. These characteristics were used in evaluating the four ages of rocks; Jurassic, Early Cretaceous, Late Cretaceous, and Tertiary for their potential for reservoirs.

The Jurassic rocks are only partially penetrated in nearly all the wells to as much as 12,000 feet. This section is very sandy but it has uniformly low porosity and permeability due to cementation. These rocks have poor reservoir potential.

The Early Cretaceous rocks range in thickness from 0 to 2,500 feet. Although this interval has numerous sands, the sands have low porosities and permeabilities. The reservoir potential for the Early Cretaceous is considered to be poor.

Rocks in the Late Cretaceous are both marine and non-marine. The marine section has from 1,000 to 5,000 feet of siltstone. These rocks have very few sands and the sands have low porosity. In contrast, the non-marine rocks are sandier, have marginal porosities, and two wells to the north encountered non-commercial quantities of oil. The marine rocks are considered to have poor reservoir potential while the non-marine rocks have good reservoir potential. The non-marine section has only been found in the west central part of Cook Inlet.

The Tertiary rocks are Eocene to Paleocene in age. These rocks are from 500 to 1,000 feet thick and their lithology changes from tuffaceous siltstone to a massive conglomerate. This section has low porosity and has very poor reservoir potential.

The petroleum potential for the planning area is considered low. Ten of the best prospects in the area have been drilled with non-commercial oil shows being present in only two. All wells showed the marked lack of good reservoir rock.

## 3. Geohazards

Seismicity, vigorous sea floor erosion, volcanic activity, shallow gas accumulations, and active faults all pose potential hazards to hydrocarbon exploration and production. Local seismic events, commonly ranging from 3 to 6 Richter magnitude, are characterized by high-frequency vibrations whose potential for damage is highest for rigid, non-reinforced structures, e.g., ladders and



piers. The low frequencies, the most damaging, pose a serious threat to large structures such as production development equipment. Shallow faults and gasification of near surface sediment pose a threat to both exploration and production operations. Other hazards include tsunamis and seiches.

Catastrophic eruption of one of the Aleutian Range volcanoes is a possibility and could result in a major ashfall throughout the planning area.

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# P. North Aleutian Basin

North Aleutian Basin is bordered by mainland Alaska to the northeast and the Alaskan Peninsula and Unimak Island to the south-southwest. The primary geologic feature which is thought to be hydrocarbon productive is an inner-shelf basin situated along the southern end of the Alaskan Peninsula.

The area is prone to seismic events and volcanoes. It is also subject to occasionally strong wind and wave conditions and ice in severe winters.

Bristol Bay is extremely productive and supports a very valuable crab and bottom fishing industry, as well as one of the world's largest salmon fisheries. The salmon migrate along the Alaskan Peninsula.

Izembek Lagoon, at the southern edge of the Alaskan Peninsula, is an extremely important feeding and staging area for migratory birds. This area also supports eel grass beds which are among the most productive in the world. As with other southern Alaskan areas, this planning area is also highly productive for marine mammals; it also serves as a migratory pathway for whales. Eight endangered whale species and four endangered bird species inhabit the area seasonally.

Subsistence use of the coastal area, including coastal salmon fisheries, is high.

## 1. Regional Geology

The North Aleutian Basin planning area lies north of the Alaska Peninsula and east of longitude 165° west. Measuring approximately 475 x 200 miles, the basin encompasses about 95,000 square miles. From the northwest, basement rocks gradually deepen to the basin axis but rise abruptly to the southeast of the axis to the northwest-facing foothills of the Alaska Peninsula.

Three geologic trends lie within the planning area. The North Aleutian Basin proper lies north of latitude 55° 45' and is oriented approximately east-west. On its southern boundary is the Black Hills uplift, which trends westward from Cape Leontevich. To the south of the uplift lies the Amak Basin. The large graben in St. George's Basin extends a few dozen miles into the west central portion of the planning area.

Sedimentary fill of the basin consists of up to 20,000 feet of Cenozoic sediments, thickest in the southeast part of the basin. Major Paleogene formations exposed onshore include, in order of decreasing depth, Tolstoi, Meshik, and Stepovak. The Tolstoi and Meshik Formations are largely volcanic conglomerate, sandstone, and breccia with some interbedded siltstones. The Stepovak has, in addition to volcanic sandstones and conglomerate, thick beds of black siltstone; and there are lignite seams in the upper part of the sequence. All three formations are dense and highly indurated. In the Neogene, the Bear Lake and Milky River are the two prominent formations. The former is porous sandstone and conglomerate with interbedded siltstone; the latter, lying above it, is conglomerate, sandstone, and mudstone. The Neogene formations and overlying Pleistocene volcanic flows and breccias were deposited in shallow-marine and non-marine environments. Seismic data strongly suggests that these same formations continue offshore, and dip to greater depths there.

2. Petroleum Potential

Ten wells were drilled on the Alaska Peninsula adjacent to the axis of Bristol Bay. Although a number of oil and gas shows were reported, none suggest a discovery of commercial size. One COST well has been drilled. Data from the onshore wells suggests that the most prospective area for hydrocarbons lies offshore from Port Moller to Amak Island. Later geophysical work shows that this area contains both the thickest Tertiary section and also the most promising anticlinal structures.

In addition to those, there are less promising structures in the southwest corner of the basin and to the north of Port Heiden. There may also be stratigraphic or fault traps along the south flank of the Black Hills uplift.

The Gulf Sandy River and Pan American David River wells suggest that the Middle to Late Miocene sandstones of the Bear Lake Formation have the greatest reservoir potential. Above 6,300 feet, these sandstones have porosities as high as 36.5 percent and permeabilities as high as 1,286 millidarcies (mD). Below 6,300 feet, the corresponding high values are 29 percent and 43 mD. Shows of oil and gas have been reported from the Bear Lake sandstones in both wells, and may possibly occur offshore also.

The best Tertiary source rocks appear to be the black marine siltstone and shale beds in the Oligocene-age Stepovak Formation. Analysis of several wells onshore shows the Paleogene strata are rich in organic matter but thermally immature. Offshore, however, these rocks should be more mature owing to the greater depth of burial. Other potential source rocks include the basal units of the Bear Lake (where buried deeply) and marine shales of Late Jurassic and Late Cretaceous age (if in angular discordance with overlying reservoir rocks).



3. Geohazards

Seismicity, vigorous sea floor erosion, volcanic activity, shallow gas accumulations, and active faults all pose potential hazards to hydrocarbon exploration and production. Local seismic events, commonly ranging from 3 to 6 Richter magnitude, are characterized by high-frequency vibrations whose potential for damage is highest for rigid, non-reinforced structures, e.g., ladders and piers. When the Shumagin gap ruptures, the energy release could range as high as 9 Richter magnitude and produce a broad spectrum of frequencies.

The low frequencies, the most damaging, pose a serious threat to large structures such as production development equipment. Shallow faults and gasification of near surface sediment also pose a threat to both exploration and production operations. Other hazards include tsunamis.

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Q. St. George Basin

St. George has similar types of geologic prospects as North Aleutian Basin, with possible hydrocarbon structures extending seaward (northwest) from Unimak Pass. It shares similar geologic and meteorologic hazards. There is potential for severe storm conditions, high waves, seismic events, sediment mass movement, gas charged sediments, and local erosion.

One of the unique features of the planning area is Unimak Pass, through which whales and other cetaceans and fur seals migrate. The Pribilof Islands also represent a unique resource, seasonally supporting millions of nesting sea birds and most of the world's population for northern fur seals. High concentrations and large numbers of other pinnipeds also inhabit the Pribilofs and the Aleutian Chain.

Subsistence use of the Aleutian Chain and Pribilof Islands is high; in addition, Unalaska/Dutch Harbor and Cold Bay serve as transportation centers and support centers for the fishing industry and the entire region.

1. Regional Geology

Two major depocenters for Tertiary sediments occur on the continental shelf in the planning area: the St. George graben and the Pribilof Basin. The St. George graben is 10 to 25 miles wide, extends approximately 200 miles in a northwest/southeast trend, and contains as much as 40,000 feet of Tertiary sediments. The Pribilof Basin is a half graben that is 30 miles wide, extends approximately 70 miles in a northwest/southeast trend, and contains as much as

20,000 feet of Tertiary sediments. The shelf area south of the graben to the continental slope contains as much as 10,000 feet of Tertiary sediment over mostly sedimentary Mesozoic rocks. The area up to within 25 miles north of the graben contains 3,000 to 7,000 feet of Tertiary sediment over igneous Mesozoic rock. The remainder of the shelf area has a very thin Tertiary section over igneous basement and is not considered prospective.

COST No. 1 well was drilled about 25 miles south of the graben and encountered about 10,000 feet of Tertiary sediments overlying the igneous rock basement. COST No. 2 well was drilled along the southeastern margin of the graben and encountered over 12,000 feet of Tertiary sediments overlying Mesozoic sedimentary rocks. The Mesozoic rocks ranged in age from Late Jurassic to Early Cretaceous and were mostly fine-grained sandstones with minor shale and coal stringers. They were derived from a volcanic source terrane and deposited in a fluvial to deltaic environment. The Tertiary sediments ranged in age from Middle Eocene to Recent. Dominant lithologies included fine-grained sandstones, siltstones, mudstones, and minor conglomerate. Volcanic rock fragments were common throughout. The sediments were deposited in mostly a marine shelf environment.

2. Petroleum Potential

The basin is in the early stage of exploratory drilling. Two COST wells and ten exploratory wells have been completed as of July 1, 1986.

Potential traps in the graben include faulted anticlines, upthrown fault traps over basement horst blocks, downthrown fault traps along border faults of the graben, drape of tertiary strata over basement fault blocks, stratigraphic onlap of Tertiary sediments onto the basement, and possible stratigraphic pinchout of sands. Outside of the graben, potential traps include sub-unconformity truncation below the Cenozoic-Mesozoic unconformity, anticlinal structures within the Mesozoic section, drape of Tertiary strata over Mesozoic highs, fault-bounded traps, and stratigraphic onlap of Tertiary sediments onto Mesozoic highs. In the Pribilof Basin, potential traps include anticlines within the Mesozoic section with drape in the overlying Tertiary section, upthrown fault traps over tilted basement blocks, and sub-unconformity truncation associated with fault-bounded anticlines.

The best potential reservoir rocks are believed to occur in the Oligocene section. At COST No. 1 Well, Oligocene sands attained thicknesses greater than 150 feet. Porosities were as high as 25 percent and permeabilities were as high as 37 millidracies. The volcanic rock fragments tend to reduce porosity and permeability because of diagenetic alteration to zeolites and clay minerals. The Mesozoic sandstones at COST No. 2 Well were very tight.

The source rock potential as indicated by the COST wells appears to be low. The sediments were low in total organic carbon and were deposited under oxidizing conditions. Only gas-prone kerogen types were present in samples from the wells. The geothermal gradient is approximately 1.5° F/100 feet. Vitrinite reflectance data indicated the Tertiary sediments to be immature for oil generation. The "oil window" occurs at approximately the base of the Tertiary section.

The deeper portions of the St. George graben may have better source rock potential than the COST well sites, because the basal graben sediments were deposited in an enclosed basin when the area south of the graben, where the COST wells were drilled, was emergent. Restricted circulation in the early stage of



graben development may have been conducive to organic preservation. Thermal maturity in the graben may also be more favorable than for the COST well locations. This is because the basal graben sediments are buried more deeply than the lowermost Tertiary sediments at the COST well sites, and therefore, may have been exposed to high enough temperatures for a sufficiently long time to generate oil. The basal Tertiary section in the Pribilof Basin may also contain favorable source rocks.

3. Geohazards

Potential geologic hazards in the planning area include shallow gas, shallow faults, seismicity, volcanism, and unstable slopes. Other environmental constraints are associated with the harsh climate, such as pack ice, superstructure icing, and storm waves. Tsunamis and seiches are other hazards.

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R. Navarin Basin

Navarin Basin is closer to the Russian mainland (about 90 miles) than it is to the Alaskan mainland. The eastern boundary of the planning area is about 30 miles west of St. Matthew Island, about 180 miles from the larger island of Nunivak and over 200 miles from the mainland. A large northwest/southeast trending basin is situated along the center of the planning area which may be hydrocarbon productive. Faulting, gas charged sediments, and sea floor slumping are the major geohazards.

While weather conditions are generally similar to other Bering Sea areas, this area is annually covered with ice, and the area is subject to high wave conditions, storm currents, and ice-wave coupling.

The region supports a large bottom fishery which, at this time, is predominantly foreign. East of the planning area, St. Matthew and Nunivak Island, are important waterfowl and shorebird areas (they are wildlife refuges). The entire Kuskokwim-Yukon delta which is shoreward, but over 200 miles from the planning area is also an important waterfowl and shorebird area. Six endangered whale species and two endangered bird species inhabit the area seasonally.

1. Regional Geology

The Navarin Basin consists of three en echelon subbasins filled with more than 26,000 feet of layered Tertiary sedimentary rock. The subbasins formed as a result of extensional deformation associated with strike-slip motion or oblique subduction of the Kula Plate beneath the North American Plate in the Late Cretaceous to early Tertiary time. Basin axes trend northwestward and parallel the continental shelf break. By the late Eocene, movement of the Kula Plate was isolated by subduction at the Aleutian Arc. Subbasin subsidence in response to structural downdropping remained active until the late Oligocene. This allowed the continuous deposition of marine mudstones and siltstones throughout most of the Paleogene. Sea level lowerings in the "middle" and late Oligocene, however, exposed older Tertiary and Mesozoic basement highs to wave-based erosion, which resulted in the deposition of coarser grained material along the subbasins flanks. Cessation of Kula Plate subduction by the late Eocene was followed by crustal cooling which allowed regional subsidence beyond structurally defined subbasins. Middle and outer neritic mudstones and sandy mudstones were deposited throughout the Neogene, with a possibility of coarser grained deposits flanking basement highs that were exposed to wave-base erosion during a sea level lowering in the late Miocene.

2. Petroleum Potential

ARCO Alaska, Inc., drilled a Continental Offshore Stratigraphic Test (COST) well in the summer of 1983. Stratigraphic test well data indicate the late Eocene and early Oligocene mudstones to be the most favorable source rocks in the Navarin Basin. This stratigraphic sequence thickens in the deeper parts of the subbasins, thus possibly providing significant amounts of oil-prone rocks at a favorable level of thermal maturity. Possible reservoir rocks are Oligocene sandy mudstones, basal sands deposited by the early Tertiary transgression over the Mesozoic basement rocks, and coarse grained deposits flanking basement highs that were deposited during sea level lowerings in the Oligocene and Miocene. Traps found in the basin include anticlines, faulted anticlines, fault traps, and stratigraphic pinchouts. Many traps are adjacent to the potential source rocks, however, traps that are not adjacent may be fed by hydrocarbon migration along unconformities, faults, and through permeable strata.

As of July 1, 1986, 8 exploratory wells have been completed. There are no known hydrocarbon accumulations in the Navarin Basin or other Tertiary basins in the Bering Sea. The major problem facing hydrocarbon production in the Navarin Basin will be finding significant amounts of reservoir rocks.

3. Geohazards

Sea-floor instability, gas-charged sediments, and possible over-pressuring are major geologic hazards in this basin. Sea-floor instability hazards which may affect bottom-founded structure include faulting, seismicity, slides, and erosion. Shallow gas-charged sediments may result in unstable foundation conditions. Investigations of surface samples indicate that most shallow gas is biogenic in origin, however, thermogenic gas may be present. Unpredicted abnormal hydrostatic pressures can be hazardous during drilling. Abnormal pressures were encountered in the Tertiary rocks during the drilling of



the stratigraphic test well. Basin characteristics such as shale diapirs, gas-charged sediments, and a thick, rapid accumulation of fine grained material indicate that overpressuring may be prevalent in the basin. Other hazards are sea ice, and superstructure icing.

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S. Norton Basin

Norton Basin planning area is situated along the southern portion of the Bering Strait and includes Norton Sound and St. Lawrence Island; the Yukon River delta forms the southeastern landward boundary of the planning area. A large, inner-shelf basin situated generally in the center of the planning area may contain hydrocarbons. Geohazards of this area include shallow gas, buried peat layers, and ice-gouged sediment, faults and earthquakes.

The weather in this planning area is severe much of the year and there is ice cover during the winter months in all years.

The shoreline throughout much of the area consists of beaches, cliffs, barrier spits and islands, and tidal flats, except for the Yukon River delta in the south. This delta area, as well as St. Lawrence Island, hosts extremely high numbers of nesting waterfowl and seabirds, respectively.

The Bering Strait is used as a migratory passage for the bowhead and beluga whales, walrus and other marine mammals, as well as migratory birds. Six endangered whale species and three bird species inhabit the area seasonally.

Coastal uses include subsistence hunting and fishing. There are small commercial fisheries for herring and crab in the sound. Nome is situated along the northern landward boundary of the planning area. It is a transportation and commercial center for northwestern Alaska. Historically, Nome has been a mining center as well.

1. Regional Geology

Norton Basin consists of two subbasins filled with more than 14,000 feet of layered Tertiary sedimentary rocks. The Basin formed as a result of pull- apart tectonics associated with Late Cretaceous or early Tertiary strike-slip motion along the Kaltag fault. Apparently the two subbasins were not formed until the mid-Eocene when the north-trending Yukon horst developed as a common boundary. Continental sedimentation dominated Norton Basin prior to the mid-Eocene. Until the mid-Oligocene the horst allowed the shallower marine siltstone and sandstone sequence to be deposited in the eastern subbasin, whereas deepwater clastics were deposited in the western subbasin. Post mid-Oligocene deposition extended beyond the controlled subbasins indicating regional subsidence in response to crustal cooling. This extension unified deposition from late Oligocene to present within the two subbasins. This sequence of rock is mainly Oligocene coals and Neogene shallow-marine siltstones, sandstones, and diatomaceous mudstones. The Oligocene consists mainly of mudstones, siltsones and sandstones with well over half of the sediments coal-bearing.

2. Petroleum Potential

ARCO Alaska, Inc., drilled two COST wells in the planning area during the summers of 1980 and 1982. Post-Sale 57 activity included 6 exploratory wells drilled as of July 1, 1986.

Stratigraphic test well data indicated the most common organic material present is Type III humic kerogen. Sufficient maturity for oil generation exists below 9,500 feet in the western subbasin and 10,600 feet in the eastern subbasin. The area is considered gas prone. Below 13,000 feet there is insufficient organic carbon to serve as a commercial hydrocarbon source. Sandstone porosities of greater than 13 percent and permeabilities of 1 millidarcy are restricted to depths less than 9,000 feet (mid-Oligocene or younger) in the eastern subbasin. Sandstone with porosities of greater than 24 percent and permeabilities of 1 millidarcy are restricted to depths less than 6,000 feet (late Oligocene or younger) in the western subbasin.

Anticlines, faulted anticlines, fault traps, and stratigraphic pinchouts are present in the Norton Basin. Faults and unconformities are present to provide migration routes. The major problem facing Norton Basin hydrocarbon production is having a sufficient amount of source rocks with the proper kerogen. There are no known oil and gas fields within Norton Basin or similar Tertiary basins in the Bering Sea continental shelf.

3. Geohazards

Sea-floor instability in the form of ice-gouging, current erosion, seismicity and gas-charged sediments may be hazardous to bottom founded structures. Gas-charged sediments are most likely biogenic in origin, however, thermogenic gas accumulation is present at one known site. Geohazards also include coastal erosion, liquification of seafloor sediments, and current scouring of sediments. Other hazards may consist of sea ice, storm surges, migratory shoals, super-structure icing, and over ice flooding.



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T. Hope Basin

Hope Basin is roughly equivalent to Kotzebue Sound and is similar in many respects to Norton Sound to the south. The Seward Peninsula which separates them forms the eastern boundary of the Bering Strait. The greatest natural hazard in the area is ice, which is present nearshore about 9 months out of the year. Geologic considerations include subsurface discontinuous permafrost and ice-gouging. Oceanographic conditions are characterized by high waves, storm currents, and high winds.

A low coastal plain forms the shoreline of the Hope Basin planning area. The area is extensively used by breeding waterfowl, shorebirds and seabirds, as well as non-breeding migratory birds. The area also supports large numbers of breeding marine mammals and is the migratory corridor for the bowhead whale and other endangered wildlife (four whale species and two bird species) and non-endangered marine mammals.

Kotzebue is located in the eastern part of the planning area, and with the population of 2,500, is nearly as large as Barrow. It is a major arctic transportation and service center. Subsistence hunting and fishing, including for the bowhead whale, is a major use of the area.

1. Regional Geology

Hope Basin is a Late Cretaceous to Tertiary sedimentary basin. Its northern limit is defined by a zone of normal faults that parallel the southern flank of the northwest striking Herald Arch overthrust which lies to the north outside of the planning area. It is bounded on the south by an east-west trending basement ridge that may be an offshore extension of the Kobuk fault zone.

The basement throughout the area probably consists of Late Cretaceous or older rocks of the Brooks Range orogen. On the basis of seismic reflection character, refraction velocities, and relative stratigraphic position the basin fill probably is Late Cretaceous to Paleogene nonmarine mudstones, siltstones, and sandstones, overlain by Neogene marine and nonmarine shales, and possibly sandstones with a combined total thickness locally exceeding 17,000 feet. The early Tertiary sediment fill is draped over the crest of basement highs and chaotically fills in the intervening troughs. The later Tertiary sediments have filled in the basin in sub-horizontal layers.

Northwest-southeast trending normal faults in the northern Hope Basin and east-west trending basement ridges in the southern Hope Basin are the dominant structural features. Generally, the basement is faulted into a ridge and trough configuration. The crests of some of these ridges are within 2,500 feet of the seafloor and the basement in the troughs reaches depths as great as 17,000 feet. In the northern part of the area, the ridges are essentially horst blocks or tilted normal fault blocks and in the southern part, the linear ridges, may be related to major strike-slip tectonics of the Kobuk fault zone. Basement faulting appears to have begun in the the late Cretaceous and continued into the mid-Tertiary. Tertiary normal faulting is of at least two generations: that directly related to active basement faulting and that created by compaction of the sedimentary section over basement highs.

2. Petroleum Potential

Two exploratory test wells drilled on native land, the Nimiuk Point No. 1 and the Cape Espenberg No. 1 wells, were drilled on Baldwin Peninsula and south of the entrance to Kotzebue Sound just east of the planning area in 1974 and 1975 by Standard Oil of California. The Kotzebue Sound wells penetrated from 3,500 to 4,000 feet of Quaternary sediments and from 2,500 to 4,000 feet of Tertiary rocks that lie on Devonian or older metasedimentary basement. The rocks in these wells show excellent reservoir properties with an average sand content for the total section of over 50 percent and average porosities over 25 percent. However, these favorable reservoir properties may be due to the proximity of the rocks to the source terrane and may not be representative for rocks in the deeper offshore Hope Basin.

Many structural, stratigraphic, and fault traps may exist in the basin on the crest of or adjacent to the basement horst blocks. However, because of poor potential for source rocks in the pre-Tertiary basement and the generally thin thermally immature Tertiary sedimentary section, the prospect for oil accumulation is low, with the possible exception of traps adjacent to locally thicker sections.



3. Geohazards

Water depths average about 120 feet but range to over 200 feet in the planning area. The dominant sediment type, covering the northern two-thirds of the seafloor in the Hope Basin, is modern current transported silts from the Yukon and other southern rivers. Near the Bering Strait relict or ice-reworked sand is prevalent, and wave sorted and tidal-current sand forms shoals and offshore bars on the northern coast of the Seward Peninsula.

Ice-gouging of the seafloor in the Hope Basin is generally less intense than in the Chukchi or Beaufort seas to the north. The gouges are more dense in water depths less than 120 feet and do not exist in water depths greater than 200 feet. The presence of these seafloor features is nearly ubiquitous throughout the planning area but are more common nearshore and on the flanks of shoals. The orientation of the gouges is controlled by local bathymetry. Incision depths of the gouges average from about 6 feet to as deep as 15 feet.

Acoustic anomalies identified on seismic records indicate the possible presence of shallow gas in the Tertiary section. Whether these anomalies represent biogenic gas, which is probably not overpressured, or thermogenic gas accumulations, which may be overpressured, is not presently known.

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U. Chukchi Sea

This planning area is situated in the western portion of the arctic area north of Alaska and adjacent to the National Petroleum Reserve in Alaska. Promising geologic features cover virtually the entire planning area from the State-Federal boundary seaward.

Sea ice, including 9 months of shorefast ice and year-round offshore pack ice which can migrate inshore, is the chief obstacle to oil and gas operations. The planning area is also subject to severe arctic storms. Geologic hazards include subsea permafrost, erosion by ice and ice gouging, and thermogenic gas although none is presently reported in the Chukchi Sea.

The nearshore and onshore areas include productive lagoon and river delta habitats, which are critical seasonal feeding areas and breeding areas for migratory birds. The area is also used by a few species of marine mammals in large numbers, including the bowhead whale which is central to the subsistence lifestyle of area natives. Four endangered whale species and two endangered bird species inhabit the area seasonally.

Barrow is a major distribution center and regional government and native population center.

1. Regional Geology

Two geological provinces, the Chukchi Basin and the northern Hope Basin, exist within the planning area. Each exhibits a distinct stratigraphic sequence and has contrasting but tectonically related structural elements. These two provinces are separated by a prominent structural feature, the Herald Arch.

The three stratigraphic sequences present in the Chukchi Basin, Franklinian, Ellesmerian, and Brookian, appear to be an offshore extension of regional western North Slope stratigraphy. These sequences represent stages in the tectonic development and depositional history of the basin. The Franklinian sequence encompasses Cambrian to Late Devonian rocks which provided a stable platform for subsequent deposition and constitutes economic basement on the North Slope. The Ellesmerian sequence, Early Mississippian to Early Cretaceous in age, is comprised of transgressive shallow shelf marine carbonates, marine and nonmarine sandstone, and shale derived from a northerly source terrane. The Brookian sequence, Early Cretaceous to present age, is comprised of deep water to nonmarine northwardly prograding deltaic sediments.

The northern portion of the Hope Basin extends into the southern portion of this planning area. The block-faulted basement, possibly Cretaceous in age, is believed to be overlain by nonmarine to marine Tertiary clastic rocks.

The significant structural elements can be divided into two groups based on time of formation. These are the Paleozoic elements which include the Barrow Arch, Arctic Platform, Chukchi Platform, and the Hanna Trough, and the Mesozoic to Early Tertiary elements which include the North Chukchi Basin, Herald Arch, Northern Hope Basin, the Fold and Thrust Belt, and the Colville Trough.

2. Petroleum Potential

The first exploration permit for the Chukchi Sea planning area was issued in 1969. Although considerable interest has been exhibited by industry recently, no COST wells or exploratory wells have been drilled. A COST well is planned for the Summer of 1987. Therefore, it is necessary to extrapolate stratigraphic relationships from well control in the adjacent National Petroleum Reserve in Alaska (NPRA). Exploration efforts in the NPRA area began in 1904 with surface geologic exploration and are continuing, although no major oil or gas fields have been discovered.

The best potential source rocks in the western NPRA and in the Chukchi Basin appear to be the Shublik Formation, the Kingak Shale, and the Pebble Shale of Ellesmerian age, and the Brookian Torok Formation, based on their high organic carbon content and high percentage of oil-prone kerogen. Vitrinite reflectance values indicate these rocks increase in thermal maturity and tendency for gas production to the south towards the Colville Trough.



The most prospective reservoirs in the planning area would appear to be the Lisburne Group, the Sadlerochit Group, the Shublik Formation, and the Sag River Formation which are all oil productive in the vicinity of Prudhoe Bay. The best potential reservoir rock is the Sag River sandstone due to its high sand content and high porosity values.

Both structural and stratigraphic traps are present in the planning area. Structural traps predominate in the Hanna Trough, North Chukchi Basin, and the Northern Hope Basin. Stratigraphic traps predominate in the Barrow Arch and Chukchi Platform regions.

The areas with the highest hydrocarbon potential appear to be the northeastern and western portions of the basin - the North Chukchi Basin, Barrow Arch, Arctic Platform, and the Chukchi Platform.

3. Geohazards

Potential geohazards include ice-seabed interactions, shallow gas accumulations, migrating bedforms, natural gas hydrates, coastal erosion, and sediment slumping near the shelf and on the slope. There is low probability of a large-scale seismic event and no evidence for subsea permafrost. Other hazards are storm surges and an extensive ice pack.

4. Supplemental Reading


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V. Beaufort Sea

This planning area, called Diapir Field in the 1982 program, includes continental shelf, slope, and abyssal plain physiographic provinces extending from the Canadian border past the western boundary of the planning area into the Chukchi Sea area. The geologic and meteorologic conditions are similar to those of Chukchi Sea. The region is a low coastal plain, characterized by numerous river deltas, such as the Colville River delta, lagoons, and barrier islands. This area supports the same type of avian and marine mammal populations as Chukchi Sea, except that bird populations are even higher. Two endangered whale species and two bird species inhabit the area seasonally.

The petroleum operations at Prudhoe Bay dominate the economy of the region. Nonetheless, while these employ area natives, subsistence activities remain extremely important both economically and culturally, especially the hunting of bowhead whales. Special stipulations have been applied in the past to leases in this region, including stipulations restricting oil and gas operations when they might interfere with bowhead whale migration.

1. Regional Geology

The Beaufort Shelf is divisible into two major provinces, including: (1) a landward area underlain by ancient continental crust termed the Arctic Platform; and (2), an area near the shelf-edge where thick clastic wedges of Cretaceous and Tertiary sediments were deposited in part upon Mesozoic oceanic crust. The highly faulted boundary between these provinces is termed the Hinge Line.

Acoustic and economic basement on the Arctic Platform consists of a metamorphic complex (Franklinian Sequence) which represents the roots of an Early Paleozoic orogen. Basement is overlain by Devonian through Jurassic strata (Ellesmerian Sequence) deposited in a stable shelf setting. The Ellesmerian Sequence thins and onlaps northward toward the ancient landmass which once existed north of the modern Beaufort continental margin. Ellesmerian sedimentation terminated in Late Jurassic time with the thermal uplift of the Arctic Platform prior to rifting in the vicinity of the present shelf edge. This uplift produced a regionally extensive Lower Cretaceous unconformity and erosional truncation of Ellesmerian strata across the northern part of the Arctic Platform. The subsequent onset of actual rift displacement produced intrarift grabens which were filled with Lower Cretaceous sediments (Rift Sequence) derived from adjacent highlands. Cooling and subsidence of the near-rift crust following breakup created the modern Barrow Arch. By Late Cretaceous time, an immense clastic wedge prograding northward from the Brooks Range orogen inundated and spilled over the Barrow Arch into depocenters along the newly-formed, fault-bounded, Beaufort continental margin. Most of the eastern Beaufort shelf is underlain by Cenozoic sediments which were deposited in this setting.

2. Petroleum Potential

Exploration for hydrocarbons in the area has been conducted since 1944, when the Department of the Navy began drilling exploratory tests at a host of localities in the central parts of the Arctic coastal plain. This work led to the discovery of several subcommercial oil and gas fields. Privately-funded exploration elsewhere on the coastal plain led to the discovery of the supergiant Prudhoe Bay field in 1968. This field contained original recoverable reserves in excess of 10 billion barrels of oil and 26 trillion cubic feet of gas.

The Prudhoe Bay field sparked oil development in northern Alaska and afforded construction of an essential pipeline transportation system from the field to an ice-free port in southern Alaska. Because of the existence of this infrastructure, other accumulations in the vicinity of Prudhoe Bay, which would otherwise be considered subcommercial (ranging from 0.3 to 1.0 billion barrels), are now being brought into production. The only proven commercial accumulation known to extend into Federal waters is the Seal Island field. The Seal Island discovery was announced by Shell in early 1984 and total recoverable reserves are presently estimated at 300 million barrels.



Three lease sales have been held in the Beaufort Sea. The most recent OCS lease offering (Sale 87) was held in August 1984. The part of the Chukchi shelf now included within the planning area has not been included within any previous sales. Thirteen exploratory wells have been completed on Federal acreage as of July 1, 1986.

Most major North Slope oil accumulations are contained in Ellesmerian Sequence reservoir formations, and any part of the Arctic Platform where these rocks are preserved is considered highly prospective. Known accumulations are trapped by a complex composite of sealing mechanisms, including faults, structural dip, and truncation at regional unconformities such as that associated with the major Lower Cretaceous erosional event. The northernmost parts of the Arctic Platform are less prospective because of the absence of Ellesmerian formations, but contain intrarift grabens within which excellent reservoir rocks deposited as part of the Rift Sequence may be present. Excellent oil source beds are thought to be present at levels of thermal maturity adequate for oil generation and expulsion in all parts of the Beaufort shelf within the planning area.

Numerous structural and stratigraphic traps exist within the thick clastic wedge seaward of the Hinge Line. Any potential reservoir sands in this area were most likely deposited in a deltaic or prodelta setting, suggesting that individual accumulations may be small due to reservoir lenticularity. This has been found to be the case in analogous geological provinces, such as the Mackenzie delta area of the Canadian Beaufort shelf. Rotational folds associated with listric faulting are the most attractive targets in the western area, while compressional folds and fault-traps are the most prevalant trap configurations in the eastern area.

Because of the narrow width of the Beaufort continental shelf, most of the planning area is underlain by the abyssal plain of the Arctic Ocean. On the basis of geological and logistical considerations, only the continental shelf extending out to the 200-foot isobath is thought to have any realistic potential for the occurrance of economic accumulations of hydrocarbons.

3. Geohazards

Geological features which may affect petroleum-related activities on the Beaufort shelf include seasonal ice cover, permafrost, strudel scouring, shallow gas, abnormal formation pressure, shallow faults, seismicity, and unstable seafloor sediments. Ice movement may exert great stresses upon surface structures and ice gouging may require burial of seafloor installations such as pipelines. Spring-flood strudel scouring of the seafloor near the mouths of major rivers is a design consideration for any installations placed there. Shallow gas may be trapped in several ways on the shelf, and constitutes a potential hazard to drilling operations. Abnormally-high pore pressures have been measured in Cenozoic strata in wells in the eastern part of the Planning Area and the nearby Canadian Beaufort. Moderate-magnitude earthquake activity has been documented in the eastern Beaufort shelf. Surface fault displacements and sediment slumps triggered by earthquakes constitute a potential hazard to seafloor installations, particularly pipelines. Geohazards also include subsea permafrost and natural gas hydrates, current transport and sediment scour, coastal erosion, migratory shoals, and sediment slumping near the shelf break. Other hazards are over ice flooding and storm surges.

4. Supplemental Reading

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Table H-1

Some Ecological Characteristics of OCS Planning Areas [1]

| Planning Areas | Acreage[2] (million) | Threatened and Endangered Species[3] | Marine Mammals[3] | Birds[3,4] |
|---|---|---|---|---|
| North Atlantic | 49 | 2 Birds<br>5 Turtles<br>6 Whales | 31 species; major feeding ground | 11.8 M; moderate shorebirds; breeding seabirds |
| Mid-Atlantic | 82 | 2 Birds<br>5 Turtles<br>6 Whales | 32 species; migratory and feeding area | 4.9 M moderate shorebirds; breeding seabirds |
| South Atlantic | 99 | 5 Birds<br>5 Turtles<br>6 Whales<br>Manatee | 32 species; Right Whale breeding area | 2.3 M (1.1 M breed) |
| Straits of Florida | 8 | 4 Turtles<br>5 Whales<br>Manatee | 31 species; Manatee migratory and feeding area | 25 species; migrant and non-migrant shorebirds, wading birds, and waterfoul |
| Eastern Gulf of Mexico | 58 | 5 Birds<br>5 Turtles<br>5 Whales<br>Manatee | 25 species (1 species breeds); 1,700 individuals breed | 300,000 (130,000 breed); seabirds |
| Central Gulf of Mexico | 46 | 5 Birds<br>5 Turtles<br>5 Whales | 25 species (1 species breeds); 1,200 individuals breed | 3.9 M (2.8 M breed); non-breeding seabirds |
| Western Gulf of Mexico | 35 | 5 Birds<br>5 Turtles<br>5 Whales | 25 species (1 species breeds); 1,200 individuals breed | 3.6 M (2.6 M breed); non-breeding seabirds |
| Southern California | 30 | 5 Birds<br>4 Turtles<br>7 Whales<br>Southern Sea Otter | 32 species (8-10 species breed); over 80,000 pinnipeds breed | 14 species (60,000 birds) breed; 80 species breeding and non-breeding |
| Central California | 15 | 6 Birds<br>4 Turtles<br>7 Whales<br>Southern Sea Otter | 18 species (8-10 species breed); over 150,000 individuals, (10,000 pinnipeds breed) | 16 species (0.3 M birds) breed |

Table H-1 (con't)

Some Ecological Characteristics of OCS Planning Areas [1]

| Planning Areas | Acreage[2] (million) | Threatened and Endangered Species[3] | Marine Mammals[3] | Birds[3,4] |
|---|---|---|---|---|
| Northern California | 29 | 6 Birds<br>4 Turtles<br>7 Whales | 18 species (6-8 species breed); over 20,000 individuals, (6,000 pinnipeds breed) | 16 species (0.3 M birds) breed |
| Washington-Oregon | 47 | 4 Birds<br>2 Turtles<br>7 Whales<br>Alaska Sea Otter | 28 species; 2 species of pinnipeds breed | 20-30 offshore species; 1.6 individuals/$Km^2$ |
| Gulf of Alaska | 133 | 7 whales<br>4 birds | 14 species (at least 3 species breed); greater than 35,000 individuals breed | 1) 2.1 M<br>2) Greater than 20 M<br>3) 849 birds/$Km^2$ |
| Kodiak | 89 | 7 whales<br>3 birds | 14 species (at least 4 species breed); greater than 35,000 individuals breed | 1) 1.0 M<br>2) N/A<br>3) 1831 birds/$Km^2$ |
| Shumagin | 83 | 7 whales<br>3 birds | 14 species (at least 3 species breed); greater than 25,000 individuals breed | 1) 4.6 M<br>2) N/A<br>3) 363-2858 birds/$Km^2$ |
| Cook Inlet | 5 | 3 whales | 15 species (at least 4 species breed); greater than 40,000 individuals breed | 1) 0.4 M<br>2) N/A<br>3) 197-111 birds/$Km^2$ |
| North Aleutian Basin | 32 | 8 whales<br>4 birds | 20 species (at least 6 species breed); greater than 100,000 individuals breed | 1) 1.9 M<br>2) 0.5 M<br>3) 245-2457 birds/$Km^2$ |



Table H-1 (con't.)

Some Ecological Characteristics of OCS Planning Areas [1]

| Planning Areas | Acreage[2] (million) | Threatened and Endangered Species[3] | Marine Mammals[3] | Birds[3,4] |
|---|---|---|---|---|
| St.George Basin | 70 | 8 whales<br>3 birds | 19 species (at least 5 species breed); greater than 1.5 M individuals breed | 1) 5.0 M<br>2) N/A<br>3) 655-1797 birds/$Km^2$ |
| Navarin Basin | 37 | 6 whales<br>2 birds | 16 species (at least 6 species breed); greater than 50,000 individuals breed | 1) 0<br>2) 0<br>3) 97-193 birds/$Km^2$ |
| Norton Basin | 25 | 5 whales<br>3 birds | 14 species (at least 5 species breed); greater than 10,000 individuals breed | 1) 2.2 M<br>2) Greater than 1 M<br>3) 343-775 birds/$Km^2$ |
| Hope Basin | 12 | 4 whales<br>2 birds | 8 species (at least 4 species breed); greater than 100,000 individuals breed | 1) 1.7 M<br>2) N/A<br>3) 775 birds/$Km^2$ |
| Chukchi Sea | 29 | 4 whales<br>2 birds | 8 species (at least 4 species breed); greater than 100,000 individuals breed | 1) 0.16 M<br>2) 0.5 M<br>3) N/A |
| Beaufort Sea | 52 | 2 whales<br>2 birds | 19 species (at least 3 species breed);greater than 50,000 individuals breed | 1) Greater than 0.1 M<br>2) N/A<br>3) 50-100 birds/$Km^2$ |

1 Additional data on the ecological characteristics of the planning areas may be found in Appendix I.

2 Planning area acreages are approximate and subject to revision.

3 Data from MMS offices, reported from numerous sources.

4 Table entries for Alaska planning areas are shown for the following categories: (1) Colonial Seabirds, (2) Coastal Migration and Nesting, and (3) High Density.

N/A = Not Available or Not Applicable; M = Million

## III. Other Uses of the OCS

A table showing uses of the sea and seabed is included in this appendix at the end of this section (Table H-2).

### A. Summary of Department of Defense Operations on the U.S. Outer Continental Shelf

Following is a description of Department of Defense (DOD) operations by Outer Continental Shelf (OCS) planning area. Discussions of classified operations are omitted.

#### 1. North Atlantic

Portions of the water and air space of the North Atlantic OCS and adjacent shoreline are used for various military operations essential to training, readiness, and support of national defense and security interests. These operations include training and testing activities such as submarine operations, gunnery practice, sea trials, radar tracking, vessel maneuvers, and general operations. These activities normally take place in areas specifically designated for such purposes that are under the control of the DOD.

The Narragansett Bay Operating Area (N8OA) is one of the major training and operating areas used by the attack submarines assigned to the Atlantic Fleet. Approximately 30 percent of these submarines have Groton/New London, Connecticut as their home port and regularly use this operating area along with newly constructed submarines undergoing sea trials and certification. Operating areas were established for training of surface, submarine, and air units and to provide designated zones for testing ordnance, aircraft, and ships.

U.S. Air Force (USAF) use of North Atlantic areas include basic fighter maneuvering, air combat training, and air-to-air intercepts.

#### 2. Mid-Atlantic

Ten submarine lanes and five Warning Areas have been identified as being necessary to DOD. The port of Norfolk, Virginia and its surrounding area is the home port for the majority of U.S. Atlantic Fleet air and surface units. A complex network of facilities is concentrated in this region to support Atlantic Fleet operations, training and readiness requirements associated with the deployment of units to the various theaters, and preparing them for contingency operations in other areas.

The Fleet Combat Training Center at Dam Neck, Virginia uses W-50 to train gunnery students in surface-to-surface and surface-to-air firing from fixed shore installations.

W-386 provides multiple training areas for numerous independent and integrated operations. Surface and airborne drone targets are used for surface and air weapons delivery including strafing, rockets, and bombs. Anti-submarine rocket and torpedo firings are routinely conducted. The Naval Air Test Center (NATC), Patuxent River launches a variety of missiles into the area with wide hazard footprints. The NATC has responsibility for the conduct of TOMAHAWK cruise missile firings for east coast surface and subsurface combatants. NATC operations in both W-386 and W-108 involve full mission flight profiles of extended low level cruise missile flights requiring tracts free of surface traffic and structures.



W-72A is primarily used for aircraft live missile firing. Radar coverage and missile impact and safety zone considerations preclude increasing the distance from shore or changing the size of the area required for these operations.

The NATC is the prime user of W-108. NATC is the Navy's principal development and test site for naval aircraft and their associated weapons systems. NATC conducts 500 to 700 test flights per year using both W-108 and W-386. Tests involve supersonic flying at high and low altitudes, air-to-air and air-to-surface missile firings, anti-submarine warfare systems evaluation, and electronic warfare system evaluations. The footprints of the missiles fired cover several hundred square miles and electronic emissions have the potential to disrupt commercial communications systems.

USAF activities in the Mid-Atlantic include readiness training for tactical fighters and interceptor aircraft, refueling operations, basic fighter maneuvering, air combat training, and air-to-air intercepts. Live ammunition is expended.

#### 3. South Atlantic

The Cape Canaveral Operating Area, submarine transit lanes off the coasts of North Carolina, South Carolina, and Florida, and the Flight Clearance Zone (FCZ) of the Kennedy Space Center (KSC) comprise the operating zones of concern in the South Atlantic area. The operating area supports ballistic missile submarine operations including the launch of test missiles and special sonar tests. The area encompasses a unique combination of launch areas and support facilities associated with submarine launched ballistic missiles of the United States and United Kingdom. Launch area positionings are predicated on unique flight path clearances and range safety restrictions for POLARIS, POSEIDON, and TRIDENT test missiles. The Air Force has safety responsibilities in the KSC FCZ for missile and space shuttle launches from KSC.

Submarine transit lanes provide safe and secure submerged transit corridors to and from submarine training and operating areas for the submarine ports of Jacksonville, Charleston, and Norfolk.

Warning Area 174 extends from the Eastern Gulf of Mexico into the Dry Tortugas and the Florida Keys. This area is used for carrier operations described above. Additional information on use of this area is expected.

#### 4. Gulf of Mexico

The two types of operations conducted by the Navy in the Gulf of Mexico which can conflict with oil and gas activities are carrier operations and Naval Coastal Systems Center (NCSC) research and development activities. A training carrier is permanently based in Pensacola, Florida to qualify student naval aviators in carrier operations before they are designated as Naval Aviators and receive assignments to more advanced training. These military operations are conducted in W-228 offshore Corpus Christi, Texas; in W-155 offshore Pensacola, Florida, and in W-174 offshore Key West, Florida. The carrier requires an area free of obstructions approximately 60 miles in diameter within 75 miles of a suitable divert field in which to operate.

The NCSC at Panama City, Florida is the principal research, development, test, and evaluation (RDT&E) center for the application of science and technology to military operations in coastal regions. The NCSC's operations include RDT&E support to mine countermeasures, diving and salvage, acoustic countermeasures, environmental technology, inshore warfare, anti-submarine warfare, and amphibious operations. These operations are conducted within a 44 nautical mile arc of a fixed point offshore Panama City.

USAF activities include basic fighter maneuvering, air combat training, air-to-air intercepts, trailing of wire antennae, and aerobatics. Live ammunition is expended.

Both the Air Force and Navy use warning areas which encompass most of the Eastern Gulf of Mexico for air-to-air and air-to-surface missile operations originating at Eglin Air Force Base, Florida.

5. Southern California

The Southern California area contains a massive integrated complex of operating areas designed to accommodate a wide spectrum of specialized warfare training, exercises, and research and development. Almost half of the U.S. Pacific Fleet's 240 ships and 1000 aircraft are based in Southern California. Because of the area's unique geographical features, the Navy has located extensive, sophisticated, instrumented ranges along the Southern California coast and offshore. Most of the Navy's research, development, and testing of new missiles, torpedoes, and other weapons as well as Pacific Fleet weapons proficiency firings in support of air, surface, and sub-surface training are conducted on these ranges. The proximity of specialized multiple operating areas to the major home port of San Diego and surrounding bases and facilities permits necessary intensive training schedules for surface, sub-surface, and air units confronted with minimum turn-around times to prepare for forward deployments to the Pacific theater and Indian Ocean.

The Pacific Missile Test Center (PMTC) at Point Mugu, California, conducts research, development, testing, and evaluation of new DOD weapons systems; conducts evaluation of operation weapons systems; and coordinates numerous exercises in assurance of fleet air and surface unit readiness. More than 1400 missile launch operations are scheduled annually. Programs and operations include: TOMAHAWK air launched Cruise Missile; AEGIS; HARPOON; SPARROW; PHOENIX; high speed antiradiation missile; Rolling Airframe missile; close in weapons systems; high energy laser; HASP and ROBIN meteorological rockets; fleet unit surface-to-air, air-to-air, and air-to-surface missile exercises; and fleet underwater exercises.



The Shallow Water Coordinated Anti-Submarine Warfare Service and Training Area 1 (CAST 1) is an anti-submarine training area, unique for shallow water conditions. Air, surface, and submarine platforms expend weapons and sonobuoys. Towed array devices and variable depth sonar operations are conducted as well as low altitude ASW aircraft operations. Live ordnance is expended.

The Coordinated ASW Services and Training Area 2 (CAST 2) is the primary area for coordinated air, surface and submarine anti-submarine warfare training. Air, surface, and submarine platforms expend live ordnance (including acoustic homing torpedoes) and sonobuoys in the area. Towed array devices and variable depth sonar operations are conducted as are low altitude ASW aircraft operations.

The Shallow Water Coordinated ASW Services and Training Area 3 (CAST 3) is used for air, surface, and submarine coordinated operator training with similar hazardous operations as in CAST 1. It is specially designed to provide sea room in conjunction with an instrumented facility for exercising new ASW long range sensors and weapons. Air, surface, and subsurface weapons and sonobuoys are expended, including live ordnance. Low altitude aircraft operations are conducted.

Fleet Training Area HOT (FLETA HOT) is used for air, surface, and submarine weapons training, large scale fleet exercise, and carrier refresher training. It includes an anti-submarine warfare training area (CAST 2) with operations similar to those performed in CAST 1. The area is used to integrate multi-weapons training operations and includes live ordnance expenditures.

The Combat System Evaluation Range/Shipboard Electronics Evaluation Facility is used for evaluating shipboard antenna radiation patterns, passive electromagnetic direction finding calibrations and electronic systems testing in conjunction with fixed shore facilities which cannot be relocated without great expense and deferral of another area of equal size.

The Camp Pendleton Amphibious Assault Area is an area in which amphibious operations are conducted. These include low altitude bombing, rocket firing and strafing, free balloon operations, submarine operations, and surface warfare training. This is the sole eastern Pacific location for full scale amphibious operations training.

The Encinitas Naval Electronic Test Area is used for surface ship and submarine operations which include torpedo firing and live ordnance as well as research and development projects.

The Fleet Training Area COLD is used for surface ship and submarine operations including torpedo firing and live ordnance. It also contains Naval Ocean Systems Center research and development projects.

The Santa Cruz Acoustic Range Facility is used for surface ship and submarine acoustic signature measurement and ascoustic research and development by the Naval Oceanographic Systems Command. This area is predominantly contained within the PMTC range.

The Coronado Island Submarine Training Area is used as a surface ship rendezvous point when exiting port and for amphibious ship training involving anchoring and landing craft launching. It includes low altitude helicopter operations involving dipping sonar, sonobuoy, and torpedo operations. Live ordnance is expended. The Tactical Maneuvering Area P-4 and Portion of W-291 connecting P-4 to FLETA HOT is used for tactical air combat training, air intercept training, air-to-air gunnery, and missile training including live ordnance.

Five submarine transit lanes pass through this area. These require unencumbered sea room for submerged transit critical for safe navigation.

The San Clemente Island Fire Area is used for long range weapons firing, drone operations (air and sea), weapons test firing, short range missile firing, air interception control and air combat training.

The San Clemente Island/Training Area is used for underwater demolition team training, underwater warfare research and development, sensor and navigation systems calibration, and weapon system acceptance tests.

The shore Bombardment Area is used for shore bombardment, bombing, strafing, rocket deliveries, drone operations, and close air support training. Live ordnance is expended.

USAF activities include basic fighter maneuvering, air combat training, and air-to-air intercepts.

The Southern California offshore area also contains impact areas for Space Shuttle solid rocket booster and external tank equipment associated with the national space program. Impacts and the impact area are similar to those of KSC in Florida.

The Space Shuttle footprint originates at Vandenberg Air Force Base in this area and extends into Central California. In addition, polar orbiting satellites and intercontinental ballistic missiles and other missiles in the testing stages are launched from various sites at Vandenberg AFB.

6. Central and Northern California

Central and Northern California Naval Operating Zones, a complex system of training and operating areas, are located between Point Conception and the northern border of California. These areas are associated with combat readiness of Pacific Fleet units operating primarily from central and northern California ports.

Warning Area W-532 is in the northern sector of the Pacific Missile Test Center (PMTC). PMTC, located at Point Mugu, California, conducts several hundred weapons systems launches each year. Launch operations are within defined limits, and the surface area within these areas and the air space above must be clear throughout the launch.



Point Reyes Warning Area W-513 is used for all-weather flight training, air intercepts, and surface operations. Live ordnance is not used in this area.

Point Reyes Electronic Range Zone is an acoustically augmented electronic range in which newly overhauled submarines are tested. San Francisco Submarine Diving Areas Uniform 1, 2, 3, 4, and 5 are surveyed locations in which the hulls of submarines are tested to assure safety. Two submarine transit lanes are used for secure submerged transit by submarines. CAST Central is a coordinated anti-submarine warfare training area in which sonobuoys and depth charges are employed.

Warning Areas W-260, W-283, and W-285 are areas used for all-weather flight training, anti-submarine warfare training, and surface operations. Aerial gunnery and air-to-surface weapons are used in this area.

7. Washington-Oregon

Submarine Operating Area Oscar is used for surface and subsurface tactical exercises, independent and multi-ship exercise, equipment tests and machinery trials.

Submarine Trial and Test Areas 3 and 4 are used for surface/subsurface tactical exercises and including equipment tests and machinery trials.

Three Submarine Transit Lanes pass through this area.

The Explosive and Chemical Dumping Areas located at Cape Flattery and the Columbia River Mouth are located in about 850 and 790 meters of water, respectively.

Warning Area 460 is used for exercise involving air to air gunnery, rockets, missiles, air to surface firing, bombing, missiles, conventional ordnance, and photoflash cartridges. Part of the area is also designated as an anti-submarine warfare training area in which sonobuoys, practice depth charges, and smoke markers are used.

Surface Exercise Area 601 is used as an ocean surface operating area using surface tactical gunnery including anti-aircraft firing and missile firing, undersea warfare exercises, and combined type exercises. Ordnance including rockets, missiles, torpedoes, incendiaries, photoflash, illumination, and gun type ammunition may be used.

Warning Area 601 is used for air to surface intermediate and low altitude bombing, strafing, and rocketry utilizing conventional ordnance and photoflash cartridges.

Sea Lion Rock is a special use area with a water target of a barren unmarked rock.

W-237A is used for air to air gunnery and rocketry, air to surface firing and bombing using conventional ordnance and photoflash cartridges.

Washington Coastal Surface Exercise Areas 237N and 237S is used for exercises involving surface tactical gunnery including anti-aircraft and missile firing. Undersea warfare and combined exercise are also conducted in these areas. Ordnance including rockets, missiles, torpedoes, incendiaries, photoflash, and illumination and gun type ammunition may be used.

Warning Area 570 is used for air intercept, aerobatics, and inflight refueling training.

USAF activities include basic fighter maneuvering, air combat training, and air-to-air intercept training.

8. Alaska

None.

B. NASA Operations Zones

Following is a description of the National Aeronautics and Space Administration (NASA) operations by OCS planning area.

1. Mid-Atlantic Planning Area

In order to avoid operational conflicts with NASA activities, NASA prefers to have some 510 blocks encompassing an estimated 2.9 million acres, which is their entire operations zone in the Mid-Atlantic planning area, removed from leasing consideration. Removal of the blocks would eliminate the possibility of an exploratory rig and/or production platform from being damaged by falling debris from rocket and missile tests.

2. South Atlantic Planning Area

The NASA Kennedy Space Center (KSC) is the principal launch and recovery site for the Space Transportation System, as well as the launch site for a variety of other space launch vehicles. The Space Transportation System, both civilian and military, is expected to continue in that capacity for a number of years. The system is now operational and the number of flights are increasing each year.

3. Southern California Planning Area

The Air Force's (as well as NASA's) concern in this area (Vandenburg Air Force Base Space Shuttle Impact Area) is that solid rocket booster (SRB) fragments from early launch aborts will result in an explosive force upon surface contact that may be hazardous for exposed personnel. Also of concern is the ability to recover the reusable SRB's from normal launches.

NASA and the Air Force requested that this area be excluded because of the hazard potential. This zone includes impact areas for Space Shuttle Solid Rocket Boosters and External Tank equipment associated with the National Space Program. The so called "foot print" extends about 143 nautical miles from shore over the DOI Southern California Planning Area.



C. Navigation Zones

The Ports and Waterways Safety Act charges the U.S. Coast Guard with the responsibility to take measures to provide safe access routes for vessel traffic proceeding to or from ports. These measures entail establishing traffic separation schemes (TSS) which divide traffic into designated inbound and outbound lanes. Designations within the TSS include the following:

- Traffic Lanes - the inbound and outbound lanes in which vessels must navigate.
- Separation Zone - the zone dividing the two traffic lanes which is used only for crossing purposes.
- Precautionary Area - a segment in which vessels must navigate with special caution and within which certain directions of traffic flow may be suggested.
- Fairway - a corridor in which all structures are prohibited.

Areas designated as Precautionary Areas, Traffic Lanes and Fairways do not allow any navigational obstruction within their boundaries.

A description of navigation zones by planning areas is presented below.

1. North Atlantic Planning Area

TSS's and Precautionary Areas have been established at the approaches to Portland and Boston Harbors, and Narragansett and Buzzards Bays.

2. Mid-Atlantic Planning Area

TSS's and Precautionary Areas have been established at the approaches to Narragansett, Buzzards, New York, Delaware, and Chesapeake Bays.

3. Eastern, Central, and Western Gulf of Mexico Planning Areas

A system of fairways connecting major Gulf ports and the deepwater oil terminal (LOOP) off Louisiana controls traffic in open Gulf waters.

4. Southern California Planning Area

TSS's and Precautionary Areas have been established for major Southern California ports.

5. Central California Planning Area

TSS's and Precautionary Areas have been established for the approach to San Francisco, and the Coast Guard is in the process of amending these zones to provide even safer port access.

Table H-2

Some Other Uses of the Sea and Seabed by OCS Planning Area

| Planning Area | Commercial Fisheries[1] Thousand Tons Landed Per Year | Commercial Fisheries[1] Million $ (1983) | Recreational[2] Fisheries (Thousand Tons Per Year) | Coastal[3] Travel and Tourism (Million $ Per Year) | Subsistence[4] Hunting and Fishing Dependence | Military[5] and Aerospace Use | Navigation[6] Zones |
|---|---|---|---|---|---|---|---|
| North Atlantic | 784 | 528 | 13 | 1,050 | N/A | M | E |
| Mid-Atlantic | 141 | 157 | 71 | 5,820 | N/A | M | E |
| South Atlantic | 481 | 140[b] | 35 | 20,560 | N/A | M | N/A |
| Straits of Florida | 43 | 19 | 11 | 4,300 | N/A | L | N/A |
| Eastern Gulf of Mexico | 100 | 95[b] | -[e] | 8,500 | N/A | H | E |
| Central Gulf of Mexico | 1,134 | 324 | 27[e] | 3,200 | N/A | L | E |
| Western Gulf of Mexico | 47 | 188 | -[e] | 4,700 | N/A | L | E |
| Southern California | 205 | 152 | N/A | 2,964 | N/A | H | E |
| Central California | 32 | 26 | N/A | 1,539 | N/A | L | E |
| Northern California | 28 | 24 | N/A | 65 | N/A | L | N/A |



Table H-2 (Continued)

Some Other Uses of the Sea and Seabed by OCS Planning Area

| Planning Area | Commercial Fisheries[1] Thousand Tons landed Per Year | Commercial Fisheries[1] Million $ (1983) | Recreational[2] Fisheries (Thousand Tons Per Year) | Coastal[3] Travel and Tourism (Million $ Per Year) | Subsistence[4] Hunting and Fishing Dependence | Military[5] and Aerospace Use | Navigation[6] Zones |
|---|---|---|---|---|---|---|---|
| Washington-Oregon | 123 | 100 | N/A | N/A | N/A | L | N/A |
| Gulf of Alaska | 292.6[a] | 232[c] | N/A | 87.5 | One third of native families receive more than one half of their food supply from subsistence resources. | L | N/A |
| Kodiak | 102.8[a] | 91[c] | N/A | 10.45 | " | L | N/A |
| Shumagin | 23.9[a] | 21[c] | N/A | 5.5 | " | L | N/A |
| Cook Inlet | 58.4[a] | 50[c] | N/A | 209.0 | " | L | N/A |
| North Aleutian Basin | 206.2[a] | 115[c] | N/A | .55 | One half of native families receive more than one half of their food supply from subsistence resources. | L | N/A |
| St. George Basin | 40.3[a] | 24[c] | N/A | 11.0 | About two thirds of native families receive more than one half of their food supply from subsistence resources. | L | N/A |

Table H-2 (Continued)

Some Other Uses of the Sea and Seabed by OCS Planning Area

| Planning Area | Commercial[1] Fisheries: Thousand Tons landed Per Year | Commercial[1] Fisheries: Million $ (1983) | Recreational[2] Fisheries (Thousand Tons Per Year) | Coastal[3] Travel and Tourism (Million $ Per Year) | Subsistence[4] Hunting and Fishing Dependence | Military[5] and Aerospace Use | Navigation[6] Zones |
|---|---|---|---|---|---|---|---|
| Navarin Basin | 27.3[a] | 27[c,f] | N/A | .05 | _[f] | N/A | N/A |
| Norton Basin | 10.6[a] | 2[c] | N/A | 2.2 | About two thirds of native families receive more than one half of their food supply from subsistence resources. | N/A | N/A |
| Hope Basin | 3.8[a] | 2[c] | N/A | 1.65 | " | N/A | N/A |
| Chukchi Sea | 0 | _[c,d] | N/A | 5.5 | " | N/A | N/A |
| Beaufort Sea | 0 | _[c,d] | N/A | 11.0 | " | N/A | N/A |

[1]U.S. Department of Commerce, National Marine Fisheries Service, Fishery Statistics of the United States, 1983, Washington, D.C., April 1984, pp. 4-5. Reported State landings were allocated to conform to planning areas in some cases, based on landings by port.

[2]Atlantic Planning Areas: NOAA. 1984. Current Fishery Statistics No. 8322. Actual data are from 1979; Gulf of Mexico Planning Areas: NOAA/NMFS. 1982 Marine Recreational Fishery Statistics Survey - Atlantic and Gulf Coast. Bell, F. W.; Sorensen, P. E.; Leeworthy, V. R., 1982. The Economic Impact and Valuation of Saltwater Recreational Fisheries in Florida.



Table H-2 (Continued)

Some Other Uses of the Sea and Seabed by OCS Planning Area

[3]Atlantic Planning Areas: Data from various State documents and offices; data not necessarily comparable. Gulf of Mexico Planning Areas: U.S. Department of the Interior, Minerals Management Service, 1984, Draft EIS for Proposed Lease Sales 94/98/102, Washington, D.C. Pacific and Alaska Planning Areas: Data from MMS Regional Offices, reported from many State and other sources; data not necessarily comparable.

[4]Data, where applicable, are from MMS Regional Offices, reported from many States and other sources; data are not necessarily comparable.

[5]Military and Aerospace Use: L=Low, M=Medium, H=High.

[6]Navigation Zones = traffic separation schemes, pathways, anchorages, etc. which are officially established; data for the Gulf of Mexico are from the U.S. Coast Guard, 7th and 8th Districts; E = established zones.

a. Amount shown is in millions of pounds.
b. Data for the east and west coasts of Florida provided by Mr. Ronald Schultze, National Marine Fisheries Service, Woods Hole, August 21, 1984. See Appendix G, Table II.A.2.1., Footnote b.
c. The 1983 value of landings for these areas was estimated by allocating the region-specific landings reported in State of Alaska, Alaska 1982 Catch and Production (July 1984) to each Alaskan OCS planning area. All 1982 dollars were converted to 1983 values.
d. Value equals less than one million dollars.
e. Amount shown for Central Gulf of Mexico is for the entire Gulf of Mexico.
f. There is no civilian population in this area.

N/A = Not Available or Not Applicable

## IV. Leasing and Development History of Planning Areas

Section 18(a)(2)(E) of the OCS Lands Act Amendments requires that the timing and location of exploration, development and production among physiographic OCS regions be based on a consideration of the interest of potential oil and gas producers, as indicated by exploration or nomination. Section 18(a)(3) requires that one consideration which must be balanced in the selection of the timing and location of leasing is the potential for discovery of oil and gas.

Tables H-3 and H-4 show pertinent information concerning leasing history and hydrocarbon development and production. Leasing history is indicated by the number of previous lease sales and by the total acreage leased and by acreage currently under lease by planning area. Hydrocarbon development is shown by cumulative production, total wells drilled, and by remaining recoverable reserves. The information presented in Table H-3 is important for assessing the likelihood of future hydrocarbon discoveries and for understanding the interest of potential producers. The rankings of interest by potential producers is in Appendix D. A brief history of OCS leasing is included in Appendix F.



Table H-3

Leasing and Development History by OCS Planning Area

| Planning Area | Prev. Lease Sales | Total Acres Leased (million) | Acres Under Lease (million) | Cumulative Production: million bbl/oil & cond. | Cumulative Production: trillion cf/gas | Total Wells: Expl. | Total Wells: Dev./Prod. | Remaining Recoverable Reserves[1]: Oil (million bbl) | Remaining Recoverable Reserves[1]: Gas (trillion cu. ft.) |
|---|---|---|---|---|---|---|---|---|---|
| North Atlantic | 1 | 0.4 | 0.0 | 0 | 0 | 8[a] | 0 | 0 | 0 |
| Mid-Atlantic | 4 | 1.3 | 0.6[c] | 0 | 0 | 32[a] | 0 | 0 | 0 |
| South Atlantic | 3 | 0.6 | 0.1[c] | 0 | 0 | 6[a] | 0 | 0 | 0 |
| Straits of Florida | 0 | 0.0 | 0.0 | 0 | 0 | 3[a] | 0 | 0 | 0 |
| Eastern Gulf of Mexico | 9 | 2.1[b] | 1.3[c] | 0 | 0 | 33[a] | 0 | 0 | 0 |
| Central Gulf of Mexico | 41 | 20.0[b] | 13.7[c] | 6,455[d] | 64.2[d] | 5,832[a] | 14,846[a] | 3,782 | 36.2 |
| Western Gulf of Mexico | 25 | 10.3[b] | 7.1[c] | 125[d] | 6.9[d] | 1,518[a] | 1,594[a] | 270 | 9.4 |
| Southern California | 9 | 1.6 | .9[c] | 340[d] | .3[d] | 298[a] | 592[a] | 1,259 | 2.1 |
| Central California | 1 | .2 | 0 | 0 | 0 | 12[a] | 0 | 0 | 0 |
| Northern California | 1 | .1 | 0 | 0 | 0 | 7[a] | 0 | 0 | 0 |
| Washington-Oregon | 1 | .6 | 0 | 0 | 0 | 12[a] | 0 | 0 | 0 |

Table H-3 (con't)

Leasing and Development History by OCS Planning Area

| Planning Area | Prev. Lease Sales | Total Acres Leased (million) | Acres Under Lease (million) | Cumulative Production: million bbl/oil & cond. | Cumulative Production: trillion cf/gas | Total Wells: Expl. | Total Wells: Dev./Prod. | Remaining Recoverable Reserves[1]: Oil (million bbl) | Remaining Recoverable Reserves[1]: Gas (trillion cu. ft.) |
|---|---|---|---|---|---|---|---|---|---|
| Gulf of Alaska | 3 | .6 | 0 | 0 | 0 | 12[a] | 0 | 0 | 0 |
| Kodiak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Shumagin | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Cook Inlet | 3 | .6 | .02[c] | 0 | 0 | 13[a] | 0 | 0 | 0 |
| North Aleutian Basin | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| St. George Basin | 1 | .5 | .5 | 0 | 0 | 10[a] | 0 | 0 | 0 |
| Navarin Basin | 1 | .9 | .9[c] | 0 | 0 | 8[a] | 0 | 0 | 0 |
| Norton Basin | 1 | .3[c] | .3[c] | 0 | 6[a] | 0 | 0 | 0 | 0 |
| Hope Basin | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Chuckchi Sea | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Beaufort Sea | 3 | 2.0 | 2.0[c] | 0 | 0 | 13[a] | 0 | 0 | 0 |



[1] Remaining Recoverable Reserves as of December 31, 1985

[a] Wells completed as of July 1, 1986.

[b] Total acres leased is more than actual acres leased because of releasing.

[c] Acres under lease as of August 7, 1986

[d] Cumulative production as of December 31, 1985.

TABLE 4

All Lease Offerings

| Lease Offer-ing | Date of Offer-ing | Location | No. of Tracts Offered | Acres Offered | No. of Tracts Bid On | Acres Bid On | Total Bonus High Bid | No. of Tracts Leased | Acres Leased | Total Bonus Leased Tracts | No. of Bids Rejected | Total Bonus Rejected | Average Per Acre | No. of Bids Rec'd. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 10/13/54 | LA | 199 | 748,819 | 90 | 394,721 | $ 116,378,476 | 90 | 394,721 | $ 116,378,476 | 0 | $ 0 | $ 294.84 | 336 |
| 1S* | 10/13/54 | LA | 108 | 523,630 | 5 | 25,000 | $ 1,233,500 | 5 | 25,000 | $ 1,233,500 | 0 | $ 0 | $ 49.34 | 5 |
| 2 | 11/9/54 | TX | 38 | 111,789 | 19 | 67,149 | $ 23,357,029 | 19 | 67,149 | $ 23,357,029 | 0 | $ 0 | $ 347.84 | 90 |
| 3 | 7/12/55 | TX,LA | 210 | 674,095 | 121 | 402,567 | $ 108,528,726 | 121 | 402,567 | $ 108,528,726 | 0 | $ 0 | $ 269.59 | 384 |
| 5 | 5/26/59 | FL | 80 | 458,000 | 23 | 132,480 | $ 1,711,872 | 23 | 132,480 | $ 1,711,872 | 0 | $ 0 | $ 12.92 | 23 |
| 6 | 8/11/59 | LA | 38 | 81,813 | 28 | 62,967 | $ 90,286,693 | 19 | 38,820 | $ 88,035,120 | 9 | $ 2,251,573 | $ 2,267.28 | 56 |
| 7 | 2/24/60 | TX,LA | 385 | 1,610,254 | 173 | 813,663 | $ 285,180,648 | 147 | 704,526 | $ 282,641,815 | 26 | $ 2,538,833 | $ 350.46 | 444 |
| 8SA* | 5/19/60 | LA | 10 | 22,085 | 1 | 2,500 | $ 75,250 | 1 | 2,500 | $ 75,250 | 0 | $ 0 | $ 30.10 | 1 |
| PH* | 12/15/61 | So Cal | 16 | 80,640 | 6 | 30,240 | $ 122,000 | 6 | 30,240 | $ 122,000† | 0 | $ 0 | $ 4.03 | 6 |
| 9 | 3/13/62 | LA | 401 | 1,808,276 | 212 | 981,407 | $ 177,745,105 | 206 | 956,407 | $ 177,260,305 | 6 | $ 484,800 | $ 185.34 | 538 |
| 10 | 3/16/62 | TX,LA | 410 | 1,875,984 | 210 | 977,092 | $ 268,724,090 | 205 | 956,592 | $ 268,333,397 | 5 | $ 390,693 | $ 280.51 | 666 |
| 11 | 10/9/62 | LA | 19 | 33,855 | 14 | 24,858 | $ 44,399,399 | 9 | 16,178 | $ 43,887,359 | 5 | $ 512,040 | $ 2,712.79 | 26 |
| P1 | 5/14/63 | CA | 129 | 669,777 | 58 | 312,975 | $ 12,807,587 | 57 | 312,945 | $ 12,807,337 | 1 | $ 250 | $ 40.93 | 70 |
| 12 | 4/28/64 | LA | 28 | 34,028 | 23 | 32,671 | $ 60,340,626 | 23 | 32,671 | $ 60,340,626 | 0 | $ 0 | $ 1,846.90 | 69 |
| P2 | 10/1/64 | OR,WA | 196 | 1,090,074 | 101 | 580,853 | $ 35,533,701 | 101 | 580,853 | $ 35,533,701 | 0 | $ 0 | $ 61.18 | 222 |
| 13S | 12/14/65 | TX | 658 | 947,520 | 50 | 72,000 | $ 33,740,309 | 50 | 72,000 | $ 33,740,309 | 0 | $ 0 | $ 468.62 | 133 |
| 14 | 3/29/66 | LA | 18 | 35,993 | 18 | 35,993 | $ 89,054,406 | 17 | 35,056 | $ 88,845,963 | 1 | $ 208,443 | $ 2,534.44 | 64 |
| 15 | 10/18/66 | LA | 52 | 227,898 | 32 | 134,717 | $ 101,730,216 | 24 | 104,717 | $ 99,164,930 | 8 | $ 2,565,286 | $ 946.98 | 79 |
| P3 | 12/15/66 | CA | 1 | 1,995 | 1 | 1,995 | $ 21,189,000 | 1 | 1,995 | $ 21,189,000 | 0 | $ 0 | $ 10,618.50 | 7 |
| 16 | 6/13/67 | LA | 206 | 971,489 | 172 | 812,202 | $ 511,957,288 | 158 | 744,456 | $ 510,079,178 | 14 | $ 1,878,110 | $ 685.17 | 743 |
| 17SA | 9/5/67 | LA | 8 | 16,995 | 1 | 2,495 | $ 30,564 | 1 | 2,495 | $ 30,564 | 0 | $ 0 | $ 12.25 | 1 |
| P4 | 2/6/68 | CA | 110 | 540,609 | 75 | 383,341 | $ 603,204,284 | 71 | 363,181 | $ 602,719,262 | 4 | $ 485,022 | $ 1,659.56 | 364 |
| 18 | 5/21/68 | TX | 169 | 728,551 | 141 | 666,631 | $ 602,475,717 | 110 | 541,304 | $ 593,899,046 | 31 | $ 8,576,671 | $ 1,097.16 | 556 |
| 19 | 11/19/68 | LA | 26 | 46,824 | 21 | 40,262 | $ 150,482,797 | 16 | 29,679 | $ 149,868,789 | 5 | $ 614,008 | $ 5,049.59 | 38 |
| 19A | 1/14/69 | LA | 38 | 96,389 | 26 | 61,628 | $ 45,588,052 | 20 | 48,504 | $ 44,037,339 | 6 | $ 1,550,713 | $ 907.90 | [illegible] |
| 20S | 5/13/69 | LA | 120 | 165,605 | 38 | 50,880 | $ 3,678,045 | 4 | 5,625 | $ 715,150 | 34 | $ 2,962,895 | $ 127.14 | [illegible] |
| 19B | 12/16/69 | LA | 27 | 93,764 | 16 | 60,153 | $ 66,908,196 | 16 | 60,153 | $ 66,908,196 | 0 | $ 0 | $ 1,112.30 | 58 |
| *Totals* | | | *3,700* | *13,696,751* | *1,675* | *7,163,440* | $ *3,456,463,576* | *1,520* | *6,662,814* | $ *3,431,444,239* | *155* | $ *25,019,337* | | *4,842* |

*S — Sulphur, *SA — Salt, *PH — Phosphate

† — Total bonuses (and rentals) were refunded due to discovery of unexploded naval projectiles on ocean floor. Amount not included in Total Bonus figure.



TABLE 4 (continued)

All Lease Offerings

| Lease Offer-ing | Date of Offer-ing | Location | No. of Tracts Offered | Acres Offered | No. of Tracts Bid On | Acres Bid On | Total Bonus High Bid | No. of Tracts Leased | Acres Leased | Total Bonus Leased Tracts | No. of Bids Rejected | Total Bonus Rejected | Average Per Acre | No. of Bids Rec'd. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Totals Brought Fwd.* | | | *3,700* | *13,696,751* | *1,675* | *7,163,440* | $ *3,456,463,576* | *1,520* | *6,662,814* | $ *3,431,444,239* | *155* | $ *25,019,337* | | *4,842* |
| 21 | 7/21/70 | LA | 34 | 73,360 | 21 | 50,889 | $ 98,101,013 | 19 | 44,642 | $ 97,769,013 | 2 | $ 332,000 | $ 2,190.07 | 59 |
| 22 | 12/15/70 | LA | 127 | 593,485 | 127 | 593,485 | $ 851,382,599 | 119 | 553,898 | $ 847,295,760 | 8 | $ 4,092,839 | $ 1,529.70 | 1,043 |
| 23 | 11/4/71 | LA | 18 | 55,872 | 13 | 42,222 | $ 96,491,023 | 11 | 37,222 | $ 96,304,523 | 2 | $ 186,500 | $ 2,587.29 | 33 |
| 24 | 9/12/72 | LA | 78 | 366,682 | 74 | 346,693 | $ 586,297,925 | 62 | 290,321 | $ 585,827,925 | 12 | $ 470,000 | $ 2,017.87 | 324 |
| 25 | 12/19/72 | LA | 132 | 604,029 | 119 | 548,374 | $ 1,673,054,912 | 116 | 535,874 | $ 1,665,519,631 | 3 | $ 7,535,281 | $ 3,108.04 | 690 |
| 26 | 6/19/73 | TX,LA | 129 | 697,643 | 104 | 566,573 | $ 1,598,590,620 | 100 | 547,173 | $ 1,591,397,380 | 4 | $ 7,193,240 | $ 2,908.40 | 551 |
| 32 | 12/20/73 | MAFLA | 147 | 817,297 | 89 | 496,917 | $ 1,491,617,119 | 87 | 485,397 | $ 1,491,065,231 | 2 | $ 551,888 | $ 3,071.85 | 373 |
| 33 | 3/28/74 | LA | 206 | 930,918 | 114 | 522,397 | $ 2,175,095,514 | 91 | 421,218 | $ 2,092,510,854 | 23 | $ 82,584,660 | $ 4,967.76 | 402 |
| 34 | 5/29/74 | TX | 245 | 1,355,678 | 123 | 680,335 | $ 1,502,429,426 | 102 | 565,112 | $ 1,471,851,831 | 21 | $ 30,577,595 | $ 2,604.53 | 352 |
| 51 | 7/30/74 | TX,LA | 258 | 1,298,739 | 49 | 249,704 | $ 76,617,645 | 19 | 100,241 | $ 30,236,800 | 30 | $ 46,380,845 | $ 301.64 | 57 |
| 36 | 10/16/74 | LA | 287 | 1,370,031 | 149 | 693,172 | $ 1,444,156,465 | 136 | 634,832 | $ 1,427,242,455 | 13 | $ 16,914,010 | $ 2,248.22 | 330 |
| | 10/16/74 | LA-ROY | 10 | 51,515 | 8 | 40,755 | $ 1,018,875 | 8 | 40,755 | $ 1,018,875 | 0 | $ 0 | $ 25.00 | 57 |
| 37 | 2/4/75 | TX | 515 | 2,870,344 | 143 | 796,367 | $ 300,632,667 | 113 | 626,585 | $ 274,690,955 | 30 | $ 25,941,712 | $ 438.39 | 281 |
| 38 | 5/28/75 | TX,LA | 283 | 1,346,432 | 102 | 486,327 | $ 250,681,156 | 86 | 406,942 | $ 232,916,050 | 16 | $ 17,765,106 | $ 572.36 | 191 |
| 38A | 7/29/75 | TX,LA | 345 | 1,772,958 | 80 | 408,009 | $ 171,511,620 | 66 | 336,301 | $ 163,214,006 | 14 | $ 8,297,614 | $ 485.32 | 179 |
| 35 | 12/11/75 | CA | 231 | 1,257,593 | 70 | 384,540 | $ 438,190,780 | 56 | 310,049 | $ 417,312,141 | 14 | $ 20,878,639 | $ 1,345.96 | 166 |
| 41 | 2/18/76 | GOM | 132 | 687,604 | 41 | 191,718 | $ 183,498,244 | 34 | 161,286 | $ 175,976,493 | 7 | $ 7,521,751 | $ 1,091.09 | 81 |
| 39 | 4/13/76 | GOA | 189 | 1,008,500 | 81 | 437,524 | $ 571,871,587 | 76 | 409,058 | $ 559,836,587 | 5 | $ 12,035,000 | $ 1,368.60 | 244 |
| 40 | 8/17/76 | Mid-ATL | 154 | 876,750 | 101 | 575,012 | $ 1,135,802,179 | 93 | 529,466 | $ 1,127,936,425 | 8 | $ 7,865,754 | $ 2,130.33 | 410 |
| 44 | 11/16/76 | TX,LA | 61 | 254,488 | 48 | 201,825 | $ 381,911,757 | 43 | 178,127 | $ 379,148,962 | 5 | $ 2,762,795 | $ 2,128.53 | 117 |
| 47 | 6/23/77 | GOM | 223 | 1,074,536 | 152 | 739,326 | $ 1,214,002,429 | 124 | 605,427 | $ 1,170,093,432 | 28 | $ 43,908,997 | $ 1,932.68 | 424 |
| C1 | 10/27/77 | Lo. CI | 135 | 768,580 | 91 | 518,080 | $ 400,319,543 | 87 | 495,307 | $ 398,471,313 | 4 | $ 1,848,230 | $ 804.49 | 240 |
| 43 | 3/28/78 | So. ATL | 224 | 1,275,273 | 57 | 324,511 | $ 109,695,692 | 43 | 244,807 | $ 100,743,443 | 14 | $ 8,952,249 | $ 411.52 | 99 |
| 45 | 4/25/78 | TX,LA | 145 | 709,727 | 101 | 490,752 | $ 767,407,369 | 90 | 438,756 | $ 733,656,893 | 11 | $ 33,750,476 | $ 1,672.13 | 283 |
| 65 | 10/31/78 | GOM | 89 | 511,709 | 35 | 201,295 | $ 61,176,730 | 35 | 201,295 | $ 61,176,730 | 0 | $ 0 | $ 303.92 | 62 |
| 51 | 12/19/78 | TX,LA | 128 | 643,987 | 88 | 449,691 | $ 884,589,799 | 81 | 412,416 | $ 871,464,998 | 7 | $ 13,124,801 | $ 2,113.07 | 288 |
| 49 | 2/28/79 | Mid-ATL | 109 | 620,557 | 44 | 250,500 | $ 41,720,618 | 39 | 222,034 | $ 40,001,631 | 5 | $ 1,718,987 | $ 180.16 | 74 |
| 48 | 6/29/79 | CA | 148 | 792,845 | 55 | 294,018 | $ 573,956,402 | 54 | 288,260 | $ 572,825,418 | 1 | $ 1,130,984 | $ 1,987.18 | 112 |
| *Totals* | | | *8,482* | *38,383,883* | *3,954* | *18,744,451* | $ *22,538,291,284* | *3,510* | *16,785,615* | $ *22,108,949,994* | *444* | $ *429,341,290* | | *12,364* |

TABLE 4 (continued)

All Lease Offerings

| Lease Offer-ing | Date of Offer-ing | Location | No. of Tracts Offered | Acres Offered | No. of Tracts Bid On | Acres Bid On | Total Bonus High Bid | No. of Tracts Leased | Acres Leased | Total Bonus Leased Tracts | No. of Bids Rejected | Total Bonus Rejected | Average Per Acre | No. of Bids Rec'd. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Totals Brought Fwd.* | | | *8,482* | *38,383,883* | *3,954* | *18,744,451* | *$ 22,538,291,284* | *3,510* | *16,785,615* | *$ 22,108,949,994* | *444* | *$ 429,341,290* | | *12,364* |
| 58 | 7/31/79 | GOM | 123 | 577,517 | 88 | 424,030 | $ 1,261,358,089 | 81 | 391,183 | $ 1,247,489,022 | 7 | $ 13,869,067 | $ 3,189.02 | 316 |
| 58A | 11/27/79 | GOM | 124 | 588,601 | 96 | 450,914 | $ 1,932,894,290 | 90 | 421,519 | $ 1,913,337,938 | 6 | $ 19,556,352 | $ 4,539.15 | 322 |
| BF | 12/11/79 | Beau.Sea | 46 | 172,320 | 25 | 88,037 | $ 491,728,138 | 24 | 85,776 | $ 488,691,137 | 1 | $ 3,037,001 | $ 5,799.68 | 62 |
| 42 | 12/18/79 | No. ATL | 116 | 660,409 | 73 | 415,602 | $ 827,832,854 | 63 | 358,671 | $ 816,516,546 | 10 | $ 11,316,308 | $ 2,276.51 | 189 |
| A62 | 9/30/80 | GOM | 192 | 909,575 | 147 | 706,042 | $ 2,805,524,393 | 116 | 551,654 | $ 2,676,927,673 | 31 | $ 128,596,720 | $ 4,852.54 | 506 |
| 55 | 10/21/80 | GOA | 210 | 1,195,569 | 37 | 210,648 | $ 117,550,113 | 35 | 199,261 | $ 109,751,073 | 2 | $ 7,799,040 | $ 550.79 | 64 |
| 62 | 11/18/80 | GOM | 81 | 458,308 | 74 | 420,058 | $ 1,436,448,959 | 67 | 383,323 | $ 1,417,961,511 | 9 | $ 18,487,448 | $ 3,699.12 | 268 |
| 53 | 5/28/81 | CA | 111 | 603,613 | 81 | 432,815 | $ 2,277,856,761 | 60 | 320,579 | $ 2,047,800,089[1] | 21 | $ 24,648,000 | $ 6,387.82 | 301 |
| RS1 | 6/30/81 | AK | 175 | 996,308 | 5 | 28,466 | $ 3,091,738 | 1 | 5,694 | $ 170,496 | 4 | $ 2,921,242 | $ 29.95 | 7 |
| A66 | 7/21/81 | GOM | 212 | 1,077,931 | 162 | 829,900 | $ 2,666,828,352 | 156 | 799,912 | $ 2,649,628,752 | 6 | $ 17,199,600 | $ 3,312.40 | 419 |
| 56 | 8/4/81 | So. ATL | 285 | 1,621,901 | 54 | 307,308 | $ 363,829,954 | 47 | 267,471 | $ 342,766,174 | 7 | $ 21,063,780 | $ 1,218.51 | 120 |
| 60 | 9/29/81 | La. Cl | 153 | 858,247 | 13 | 73,158 | $ 4,405,899 | 13 | 73,158 | $ 4,405,899 | 0 | $ 0 | $ 60.22 | 15 |
| 66 | 10/20/81 | GOM | 209 | 1,081,364 | 107 | 532,064 | $ 1,280,983,917 | 102 | 508,301 | $ 1,243,468,752 | 5 | $ 37,515,165 | $ 2,446.32 | 233 |
| 59 | 12/8/81 | Mid-ATL | 253 | 1,440,376 | 98 | 557,932 | $ 424,927,000 | 51 | 290,352 | $ 323,659,000 | 47 | $ 101,268,000 | $ 1,114.71 | 240 |
| 67 | 2/9/82 | GOM | 234 | 1,219,847 | 137 | 695,765 | $ 1,251,793,459 | 115 | 590,265 | $ 1,193,654,719 | 22 | $ 58,138,740 | $ 2,022.29 | 290 |
| 68 | 6/11/82 | So Cal | 140 | 716,866 | 35 | 176,253 | $ 132,252,632 | 29 | 147,066 | $ 117,875,281 | 6 | $ 14,377,351 | $ 668.77 | 66 |
| RS2 | 8/5/82 | ATL,CA,AK | 554 | 3,142,069 | 40 | 227,727 | $ 12,310,706 | 36 | 204,955 | $ 11,149,450 | 4 | $ 1,161,256 | $ 54.40 | 48 |
| 71 | 10/13/82 | AK-DF | 338 | 1,825,770 | 125 | 683,026 | $ 2,067,604,786 | 121 | 662,861 | $ 2,055,632,336 | 4 | $ 11,972,450 | $ 3,101.00 | 252 |
| 69(1) | 11/17/82 | GOM | 144 | 732,570 | 67 | 339,999 | $ 634,919,980 | 56 | 281,213 | $ 609,178,223 | 11 | $ 25,741,757 | $ 2,166.24 | 151 |
| 69(2) | 3/8/83 | GOM | 125 | 665,478 | 13 | 68,106 | $ 39,741,340 | 11 | 58,120 | $ 37,570,900 | 2 | $ 2,170,440 | $ 646.44 | 20 |
| 57 | 3/15/83 | AK-NB | 418 | 2,379,751 | 64 | 364,364 | $ 325,267,372 | 59 | 335,898 | $ 317,873,372 | 5 | $ 7,394,000 | $ 946.34 | 98 |
| 70 | 4/12/83 | AK-SO | 479 | 2,688,787 | 97 | 552,239 | $ 427,343,830 | 96 | 546,546 | $ 426,458,830 | 1 | $ 885,000 | $ 780.28 | 150 |
| 76 | 4/26/83 | Mid-ATL | 4,050 | 22,664,991 | 40 | 227,727 | $ 71,141,240 | 37 | 210,641 | $ 68,410,240 | 3 | $ 2,731,000 | $ 324.77 | 53 |
| *Totals* | | | *17,254* | *86,662,051* | *5,632* | *27,556,631* | *$ 43,395,927,086* | *4,976* | *24,480,034* | *$ 42,229,327,407* | *658* | *$ 961,191,007* | | *16,554* |

[1] The 1/5 bonuses (totaling $41,081,734) on 12 leases were forfeited by the companies May 1984. Amount not included in Total Bonus figure.



TABLE 4 (continued)

All Lease Offerings

| Lease Offer-ing | Date of Offer-ing | Location | No. of Tracts Offered | Acres Offered | No. of Tracts Bid On | Acres Bid On | Total Bonus High Bid | No. of Tracts Leased | Acres Leased | Total Bonus Leased Tracts | No. of Bids Rejected | Total Bonus Rejected | Average Per Acre | No. of Bids Rec'd. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Totals Brought Fwd.* | | | *17,254* | *86,662,051* | *5,632* | *27,556,631* | *$ 43,395,927,086* | *4,976* | *24,480,034* | *$ 42,229,327,407* | *658* | *$ 961,191,007* | | *16,554* |
| 72 | 5/25/83 | CGOM | 7,050 | 37,867,762 | 656 | 3,249,199 | $ 3,469,214,969 | 623 | 3,089,872 | $ 3,367,606,134 | 33 | $ 101,608,835 | $ 1,089.89 | 1,015 |
| 78 | 7/26/83 | So-ATL | 3,582 | 20,156,426 | 11 | 62,625 | $ 13,362,040 | 11 | 62,425 | $ 13,362,040 | 0 | $ 0 | $ 213.37 | 12 |
| 74 | 8/24/83 | WGOM | 5,848 | 32,620,248 | 436 | 2,410,809 | $ 1,549,262,300 | 406 | 2,246,005 | $ 1,501,712,517 | 30[4] | $ 47,549,783[5] | $ 668.28 | 773 |
| 73 | 11/30/83 | So Cal | 137 | 768,341 | 8 | 43,801 | $ 16,022,336 | 8 | 43,801 | $ 16,022,336 | 0 | $ 0 | $ 365.82 | 14 |
| 79 | 1/5/84 | EGOM | 8,868 | 50,631,513 | 156 | 897,786 | $ 310,586,261 | 156 | 897,786 | $ 310,586,261 | 0 | $ 0 | $ 345.95 | 226 |
| 83 | 4/17/84 | Nav Bas | 5,036 | 28,048,995 | 186 | 1,058,932 | $ 631,228,331 | 180 | 1,024,772 | $ 624,491,331[2] | 0 | $ 0 | $ 609.40 | 425 |
| 81 | 4/24/84 | CGOM | 6,502 | 34,743,780 | 529 | 2,650,128 | $ 1,446,584,927 | 453 | 2,278,179 | $ 1,323,036,649 | 6 | $ 6,737,000 | $ 580.74 | 793 |
| 84 | 7/18/84 | WGOM | 5,446 | 30,038,593 | 402 | 2,173,724 | $ 945,717,312 | 361 | 1,949,213 | $ 844,850,488 | 76 | $ 123,548,278 | $ 433.43 | 593 |
| 87 | 8/22/84 | Diapir | 1,475 | 7,773,447 | 232 | 1,233,573 | $ 877,131,327 | 231 | 1,230,486 | $ 871,964,327[3] | 41 | $ 100,866,824 | $ 722.00 | 432 |
| 80 | 10/17/84 | So Cal | 657 | 3,147,352 | 25 | 125,100 | $ 66,231,426 | 23 | 114,367 | $ 62,121,252 | 1 | $ 5,167,000 | $ 543.17 | 30 |
| 98 | 5/22/85 | CGOM | 4,531 | 24,006,157 | 444 | 2,241,598 | $ 1,147,434,447 | 409 | 2,076,943 | $ 1,079,377,760 | 2 | $ 4,110,174 | $ 519.69 | 644 |
| 102 | 8/14/85 | WGOM | 4,879 | 27,199,074 | 210 | 1,156,852 | $ 391,137,536 | 195 | 1,075,199 | $ 359,175,656 | 35 | $ 68,056,687 | $ 334.05 | 265 |
| 94 | 12/18/85 | EGOM | 6,344 | 35,823,478 | 82 | 450,259 | $ 124,022,098 | 38[1] | 215,948 | $ 64,045,942[1] | 15 | $ 31,961,880 | $ 319.04 | 114 |
| 104 | 4/30/86 | CGOM | 5,837 | 31,382,152 | 114 | 569,418 | $ 146,367,757 | 101 | 504,814 | $ 130,276,757 | 0 | $ 0 | $ 258.07 | 129 |
| 105 | 8/27/86 | WGOM | 4,887 | 27,287,952 | 41 | 229,613 | $ 56,817,990 | 41 | 229,613 | $ 56,817,990 | 13 | $ 16,091,000 | $ 247.45 | 52 |
| | | | | | | | | | | | 0 | $ 0 | | |
| *Totals* | | | *88,333* | *478,157,321* | *9,164* | *46,110,048* | *$ 54,587,048,143* | *8,212* | *41,519,657* | *$ 52,854,774,847* | *910* | *$1,466,888,468* | | *22,071* |

Highest Per-Acre Bid — Lease Offering 53 — $65,014.16
Total Amount of All Bids Received for All Lease Offerings — $119,365,913,098
Total Amount of All Rentals for All Lease Offerings — $128,787,911

[1] In two cases (OCS-G 6240 and OCS-G 6257), the lease forms were not executed by the high bidder(s) within the time allowed, resulting in forfeiture of the 1/5 bonus deposit and their right to acquire the leases.
[2] Four tracts amounting to $5,104,000.00 included in this figure are in dispute and leases have not been issued.
[3] Seventeen tracts amounting to $108,174,000 included in this figure are in dispute and leases have not been issued.
[4] There are 39 tracts subject to Military Stipulation 5 not yet issued. Subsequent decisions will be made whether to issue leases or refund the 1/5 bonuses. Adjustments will be made to this report as they occur.
[5] This figure includes the 1/5 bonus for 39 tracts subject to Military Stipulation 5 where leases were not issued. This figure will also be adjusted as changes occur. This figure also includes 1/5 bonus on 5 tracts which was forfeited.

V. Relevant Environmental and Predictive Information

Section 18(a)(2)(H) of the OCS Lands Act, as amended, requires the Secretary to consider relevant environmental and predictive information in determining the timing and location of exploration, development, and production activities among the physiographic OCS regions. This consideration cannot be isolated from other considerations required by section 18(a)(2), especially subparts (A), (D) and (G). Analysis based on the requirements in subparts (A), (D), and (G) as well as other requirements, are included in the SID. In addition to information in Appendix H, Appendix I (Relative Marine Productivity and Environmental Sensitivity) contains further analysis of marine productivity including abundance and distribution of habitats and biota.

Much of the available, relevant environmental information on the OCS planning areas has been developed through the Department of the Interior's OCS Environmental Studies Program. The studies program was initiated in 1973 and was administered by the Bureau of Land Management until 1982. In 1982 administration of the program was transferred to the Minerals Management Service. Since its inception, the OCS Environmental Studies Program has invested more than $400 million in oceanographic and socioeconomic studies. In Fiscal Year 1983, the OCS Environmental Studies Program provided 95 percent of all Federal funds for ocean pollution research related to offshore oil and gas activities (Interagency Committee on Ocean Pollution Research, Development, and Monitoring [COPRDM], 1984).

Since its inception, the OCS Environmental Studies Program has supported studies in almost all of the planning areas. The environmental studies program funding through Fiscal Year 1985 by planning area is summarized in Table h-5.

The OCS Environmental Studies Program is currently supporting numerous studies designed to increase and improve information which supports accurate prediction of the effects of OCS activities. These studies include monitoring actual exploration and development operations and their effects on whales and marine mammals, benthic communities, and fish populations. The studies focus on the effect of spilled oil, drilling discharges, and noise generated from OCS activities. The studies program is also sponsoring some laboratory toxicity assessments. When it began, the studies program sponsored many large baseline studies in the OCS planning areas. The program's emphasis on this type of study has declined and it currently supports very few of these studies. The few remaining baseline studies are being conducted in Alaska and in deepwater areas in the Atlantic and Gulf of Mexico. The program's support of these studies will probably end within the next 2 to 3 years.

In addition to the environmental studies, the Department of the Interior has produced environmental impact statements (EIS) on the potential consequences of OCS oil and gas activities in almost every OCS Planning area. The number of EIS's written for each planning area is listed in Table H-6. An oil spill trajectory analysis is normally prepared for each EIS. The number of these analyses produced for lease sales in the various OCS planning areas is also listed in Table H-6.



TABLE H-5

OCS Environmental Studies Program Funding Through Fiscal Year 1986 by Planning Area (in $Millions)

| Planning Area | Studies Affecting Planning Area /1 | Studies Exclusive to Planning Area/2 |
|---|---|---|
| North Atlantic | $ 52.7 | $ 29.1 |
| Mid-Atlantic | 36.4 | 12.8 |
| South Atlantic | 36.0 | 22.1 |
| Straits of Florida | 0 | 0 |
| Eastern Gulf | 37.8 | 5.3 |
| Central Gulf | 43.2 | 4.6 |
| Western Gulf | 34.0 | 9.9 |
| Southern California | 43.3 | 19.1 |
| Central California | 32.3 | 4.9 |
| Northern California | 25.4 | 3.0 |
| Washington-Oregon | 6.7 | 0.2 |
| Gulf of Alaska | 65.9 | 8.6 |
| Kodiak | 71.3 | 3.4 |
| Shumagin | 20.0 | 0.4 |
| Cook Inlet | 57.4 | 2.6 |
| North Aleutian Basin | 93.1 | 5.3 |
| St. George Basin | 88.2 | 0.9 |
| Navarin Basin | 67.6 | 2.9 |
| Norton Basin | 93.7 | 5.0 |
| Hope Basin | 40.9 | 0.2 |
| Chukchi Sea | 113.4 | 7.3 |
| Beaufort Sea | 113.8 | 11.8 |

/1 Includes studies which are exclusive to the planning area, studies which include other planning areas, and studies which are generic to the region. Columns may not be added.

/2 Includes only studies which are exclusive to the planning area. Columns may not be added.

TABLE H-6

Number of Lease Sale-Specific Environmental Impact Statements (EIS)
and Oil Spill Risk Analyses (OSRA) Prepared for each
Planning area Through August 1986

| Planning Areas | Number of EIS's | Number of OSRA's |
|---|---|---|
| North Atlantic | 3 | 3 |
| Mid-Atlantic | 5 | 5 |
| South Atlantic | 4 | 4 |
| Straits of Florida | 0 | 0 |
| Eastern Gulf of Mexico | 12 | 4 |
| Central Gulf of Mexico | 20 | 6 |
| Western Gulf of Mexico | 19 | 6 |
| Southern California | 4 | 3 |
| Central California | 2 | 2 |
| Northern California | 1 | 1 |
| Washington-Oregon | 0 | 0 |
| Gulf of Alaska | 3 | 2 |
| Cook Inlet | 3 | 2 |
| Kodiak | 1 | 2 |
| Shumagin | 0 | 0 |
| North Aleutian Basin | 1 | 1 |
| St. George Basin | 2 | 2 |
| Navarin Basin | 1 | 2 |
| Norton Basin | 2 | 2 |
| Hope Basin | 0 | 0 |
| Chukchi Sea | 0 | 2 |
| Beaufort Sea | 3 | 3 |



The EIS's and the oil spill trajectory analyses, air quality analyses, cultural resource analyses, and socioeconomic analyses included in them are all supported, in part, by the OCS Environmental Studies Program. Each of the analyses listed above represents a use of studies information and a refinement of that information for relevant leasing and lease management issues. The EIS, which is required for OCS lease sales under the National Environmental Policy Act (NEPA), is a point at which these analyses and others are joined in a broad assessment of the impacts of the OCS oil and gas activities in planning areas. The EIS's contain both area-specific and generic analyses. As required under NEPA and its implementing regulations, the lease sale EIS focuses large amounts of information on relevant issues.

In addition to depending upon Environmental Studies Program information, EIS's also contain relevant information generated by other parties. Although the studies program provides most new information directly relevant to OCS issues, other programs also provide useful information. Among these programs are the whale and marine mammals programs and the fisheries programs of the National Marine Fisheries Service, oceanographic data collection programs of the National Oceanic and Atmospheric Administration, and toxicity and effects studies of the Environmental Protection Agency.

Through the EIS process, decisionmakers are provided with an additional means of focusing attention on relevant information. That mechanism includes scoping for and public review and comment on the EIS. These procedures, which are required by NEPA, insure public review of information used in the decisionmaking process. Public comments on EIS's focus on the information used and the adequacy of the subsequent analyses, thus providing the Secretary with another source of relevant environmental and predictive information. The information provided by the public is used to develop and revise EIS's, to prepare decision material, and to design additional studies to support leasing and lease management decisions.

# Appendix I

## RELATIVE MARINE PRODUCTIVITY AND ENVIRONMENTAL SENSITIVITY

APPENDIX-I

RELATIVE MARINE PRODUCTIVITY AND ENVIRONMENTAL SENSITIVITY

OIL SPILLS

CONTENTS



TABLES





RELATIVE MARINE PRODUCTIVITY AND ENVIRONMENTAL SENSITIVITY

OUTER CONTINENTAL SHELF PLANNING AREAS

## I. Introduction

Section 18(a)(2)(G) of the OCS Lands Act, as amended, requires that the Secretary of the Interior consider the relative marine productivity and environmental sensitivity of the various oil and gas bearing physiographic regions of the OCS in determining the timing and location of oil and gas activities. Analyses of relative marine productivity and environmental sensitivity were conducted to aid in the development of the 1982 OCS leasing schedule (Part II.B and Appendix 10 of the SID for the 1982 program). Those analyses demonstrated the complexity of collecting, analyzing, and interpreting scientific information to satisfy the requirements of section 18(a)(2)(G). In spite of the difficulties described in the 1982 analyses, the approaches to those analyses were upheld as reasonable by the U.S. Court of Appeals for the District of Columbia on July 5, 1983.

In preparation for current analyses, analytical approaches were discussed with the OCS Advisory Board Policy Committee (October 1984) and Scientific Committee (November 1984). The present analysis incorporates some of the advice and guidance received. Some of the suggestions from these advisory groups were more appropriate to environmental analyses which will follow the present analyses. These suggestions will be considered during the preparation of the environmental impact statement (EIS) for the Proposed Final Program and in subsequent sale-specific EIS's. Almost all parties who provided advice agreed that both the productivity and sensitivity analyses required by section 18(a)(2)(G) are complex and difficult. In addition to this advice, the Department has received or developed more information on the habitats and biota of the OCS than was available in 1982. The principal mechanism for the Department to develop such information is the OCS Environmental Studies Program administered by the Minerals Management Service.

## II. Relative Marine Productivity

The term "productivity" has a distinct meaning to marine biologists. It means the "primary productivity" of marine plants. Primary productivity is the amount of plant tissue produced through photosynthetic fixation of carbon during a standard period of time. Both phytoplankton, microscopic marine plants, and fixed or rooted plants contribute to the primary productivity of most OCS planning areas. However, phytoplankton are the most important primary producers because of their large numbers and their wide distribution. Rooted or fixed plants are generally confined to the shallow portions of the planning areas. Phytoplankton can occupy all surface waters of a planning area and can fix carbon as long as sufficient light and nutrients are available. Riley (1970) estimated the normal range of marine primary productivity to be between 50 and 150 grams of carbon per square meter of ocean surface per year. Productivity in inshore areas and areas of upwelling can be as much as ten times greater than oceanic productivity.

A. Methods

The primary productivity of phytoplankton was used to rank the various planning areas in the 1982 analysis of relative marine productivity. Measurements of phytoplankton productivity have been made in almost all of the planning areas. The methods for measuring phytoplankton productivity are relatively standard. Most of the data used in the present analysis, except that provided by Smith and Kalber (1974), is based on $^{14}C$ assimilation measurements of phytoplankton productivity. Results of phytoplankton productivity studies are expressed in terms of the amount of carbon fixed during photosynthesis per unit area in a specified time. The figures used in the present analysis are expressed as grams of carbon fixed per square meter per year ($gC/m^2/yr$). By using a period of one year for reporting primary productivity, periods of extremely high or low productivity are incorporated in their appropriate importance in terms of their contribution to the annual productivity. This is especially important in areas where productivity is highly seasonal.

The 1982 analysis of marine productivity relied upon the "Estimation of organic production in the oceans" (Figure 1.1-5) presented by Smith and Kalber (1974). The productivity ranges provided in that undocumented map were used to rank the OCS planning areas in 1982. For the current analysis, the estimates of Smith and Kalber (1974) were compared with more current estimates based upon documented measurements. These measurements are reported in many Department of the Interior EIS's for OCS oil and gas lease sales, reports from the OCS Environmental Studies Program, and other available literature (Table I-1). The productivity ranges provided by Smith and Kalber (1974) were generally supported by the more recent data.

A major difference between the 1982 analysis and the present analysis is the productivity attributed to the North Aleutian Basin and the St. George Basin, Alaska. Smith and Kalber (1974) estimated the annual productivity to range from 400 to 7300 $gC/m^2$. The upper value of this range is equivalent to an average daily productivity of 20 $gC/m^2$. This high value is twice the high productivity rate reported for phytoplankton blooms in the area by Goering and McRoy (1981). Alexander and Cooney (1978) observed that approximately 65% of annual primary production on the Bering Sea shelf occurs in blooms between April and June. Niebauer, Alexander, and Cooney (1981) measured peak productivities of 25 $gC/m^3$/hour along the ice edge in the southeastern Bering Sea. They noted that these productivity peaks normally occur during late May and persist for about two weeks. The area of peak productivity occurs within 40 to 80 km of the ice edge. As a result of these documented observations, the present analysis includes an estimate of annual primary production for the North Aleutian Basin and St. George Basin of 400 $gC/m^2/yr$ provided by Goering and McRoy (1981). This value of appears more reasonable than the range provided by Smith and Kalber (1974). The use of the summary provided by Smith and Kalber (1974) without verification of the figures for the North Aleutian Basin and the St. George Basin skewed the conclusions of the 1982 productivity analysis. The present analysis corrects that error.

Phytoplankton productivity can vary more significantly within a planning area than between planning areas. For example, O'Reilley and Busch (1984)



TABLE I-1

Marine Phytoplankton Productivity by Planning Area
Expressed as Grams of Carbon Fixed per Square Meter per Year

| Planning Area | Range of Values Used in the 1982 Analysis ($gC/m^2/yr$)* | More Recent Observations ($gC/m^2/yr$) | More Recent Observations: Reference |
|---|---|---|---|
| North Atlantic | 200-400 | 230-470 | O'Reilly & Busch (1984) |
| Mid-Atlantic | 200-400 | 260-370 | O'Reilly & Busch (1984) |
| South Atlantic | 50-200 | 130-360 | Haines & Dunstan (1975) |
| | | | Yoder et al. (1983) |
| Straits of Florida | 50-100 | | |
| Eastern Gulf of Mexico | 50-100 | 10-110 | UMES (1985) |
| Central Gulf of Mexico | 50-100 | 10-220 | El-Sayed & Turner (1977) |
| Western Gulf of Mexico | 50-100 | 15-70 | El-Sayed & Turner (1977) |
| Southern California | 200-400 | 180-360 | Eppley et al. (1979) |
| Central California | 200-400 | 10-470 | Riznyk (1977) |
| Northern California | 200-400 | 10-470 | Riznyk (1977) |
| Washington/Oregon | 200-400 | 35-350 | Small et al. (1972) |
| Gulf of Alaska | 200-400 | | |
| Cook Inlet | 200-400 | | Griffiths et al. (1982) |
| Kodiak | 200-400 | | |
| Shumagin | 200-400 | | |
| North Aleutian Basin | 400-7300 | 120-400 | Goering & McRoy (1981) |
| St. George Basin | 400-7300 | | |
| Navarin Basin | 50-200 | | |
| Norton Basin | 50-100 | | |
| Hope Basin | <50 | | |
| Chukchi Sea | <50 | 18-28 | Carey (1978) |
| Beaufort Sea | <50 | 10-20 | Schell & Horner (1981) |

* Data from Smith and Kalber (1974)

reported that productivity in the shallow areas of Georges Bank (North Atlantic) averaged 470 $gC/m^2/yr$ while in deeper waters landward of the shelf break, productivity averaged 370 $gC/m^2/yr$. Productivity in the deeper waters of the North Atlantic averaged 230 $gC/m^2/yr$. Determining an appropriate range or average productivity rate for the North Atlantic or any other planning area requires careful attention to the temporal and spatial significance of reported observations.

Even with the addition of new information, ranking the OCS planning areas by their relative marine productivity is difficult. The ranges of observed production are broad and overlap. The ranges do not provide an average or other measure of central tendency or the frequency of the observations. Ranges are not amenable to statistical comparison, and comparisons among them are tenuous at best. However, the new information appears to support the principal results of the 1982 analysis.

## B. Results

In the 1982 analysis, the planning areas were grouped into four productivity classes: highest, next-to-highest, next-to-lowest, and lowest. The North Aleutian Basin and the St. George Basin were the only planning areas in the "highest" class. Based upon the data of Goering and McRoy (1981), the average annual productivity of these planning areas is substantially lower than the values reported by Smith and Kalber (1974). As a result of the lowering of the productivity ranges for the North Aleutian and St. George Basins, only three productivity classes (high, moderate, and low) are distinguished in the present analysis (Table I-2). The placement of a planning area into any of the productivity classes in Table I-2 is based on the ranges reported in Table I-1 and on information on the appropriate areal mean productivity which may be provided by the references included in Table I-1.

Twelve planning areas are included in the "high productivity" class. Further differentiation within this group must await more precise definition of the appropriate ranges or other statistical description. The principal difference between the present analysis and the 1982 analysis is the elimination of the "highest" productivity class from the 1982 analysis and the inclusion of the North Aleutian Basin and the St. George Basin into the "high" productivity class of the present analysis.

In the present analysis, the planning areas designated as having "moderate" productivity are those with reported observations ranging from 50 to 200 $gC/m^2/yr$. Seven planning areas occur in this class.

Finally, the three planning areas in the Arctic (Hope Basin, Chukchi Sea, and Beaufort Sea) are the least productive of the OCS planning areas. Information from Carey (1978) and Schell and Horner (1981) confirms the low productivity in two of these areas.

## C. Additional Measures of Marine Productivity

The phytoplankton productivity data discussed in the present analysis are some of the most consistently expressed data in biological oceanography.



TABLE I-2

Relative Phytoplankton Productivity of the OCS Planning Areas Expressed as Grams of Carbon Fixed per Square Meter per Year

<u>High Productivity</u> (200 to 500 $gC/m^2/yr$)

North Atlantic
Mid-Atlantic
North Aleutian Basin
St. George Basin
Southern California
Central California
Northern California
Washington and Oregon
Gulf of Alaska
Cook Inlet
Kodiak
Shumagin

<u>Moderate Productivity</u> (50 to 200 $gC/m^2/yr$)

South Atlantic
Straits of Florida
Eastern Gulf of Mexico
Central Gulf of Mexico
Western Gulf of Mexico
Navarin Basin
Norton Basin

<u>Low Productivity</u> (<50 $gC/m^2/yr$)

Hope Basin
Chukchi Sea
Beaufort Sea

Even so, comparisons among observed productivities are tenuous for the reasons described in the preceding discussion. The problems associated with attempting to use other biota to assess marine productivity are illustrated in Table 6 of the 1982 analysis. Even with the additional data collected since 1982, available information is not sufficient to support a rigorous evaluation of the relative abundance of various organisms in the OCS planning areas. In many instances, quantitative information on some biota is unavailable, while for others, the development of "planning-area representative" information is not practical.

However, information on the relative abundance of eight additional categories of biota was compiled, reviewed, and used in the matrix exemplified in Table I-3 to complete the environmental sensitivity analysis. Available information on standing stocks and distributions was used to determine whether the "abundance" of the biota in a planning area relative to all other planning areas is high, moderate, or low. Making such determinations generally required extrapolations of existing data and simplifying assumptions. Some of these extrapolations and assumptions are described in the following sections.

## III. Relative Environmental Sensitivity

The concept of environmental sensitivity is even more complex than the concept of marine productivity. The 1982 analysis clearly demonstrated this complexity. Simplifying assumptions and scientific judgments were used in the 1982 analysis to develop a strategy to measure environmental sensitivity. The present analysis contains some of those assumptions and judgments. However, in many instances the assumptions and judgments have been replaced by information that was not available in 1982.

The 1982 analysis of environmental sensitivity was based, in large part, on an evaluation of the sensitivity of various coastal and marine habitats and biota to spilled crude oil. Limiting the analysis to spilled crude oil provided the following advantages:

1. Different areas of the OCS could be evaluated against a common factor, in this case, spilled crude oil.
2. Effects from overlapping factors could be avoided.
3. Oil spills, although rare, would cause the largest, most visible, and measurable effects of OCS activities.

The present analysis of environmental sensitivity also concentrates on the effects of spilled oil. However, some other factors were also evaluated in Appendix I-2 of the Proposed Program. These evaluations are not repeated in the Proposed Final Program but are available for review (see section IV.C of this appendix). These factors include the following:

1. Operational discharges from OCS activities (drilling muds, cuttings, and formation waters).
2. Noise generated by OCS activities.
3. Habitat alteration from the installation of OCS facilities.
4. Air emissions from OCS operations.



TABLE I-3

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Hypothetical

Total Score: 290

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 200 | 33 | High | 225 | 74.25 |
| Sandy Beaches | 300 | 50 | Low | 45 | 22.50 |
| Rocky Beaches | 100 | 17 | Moderate | 135 | 22.95 |
| TOTAL | 600 | | | | 119.70 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 1,200,000 | 5.3 | Moderate | 135 | 7.16 |
| Submarine Canyons | None | 0.0 | Low | 45 | 0.00 |
| Coral Reefs | 5,000 | 0.02 | High | 225 | 0.05 |
| Hard Bottoms | 600,000 | 2.6 | Low | 45 | 1.17 |
| Shelf Break Zone | 850,000 | 3.7 | Low | 45 | 1.67 |
| Mud/Sand Bottom | 20,000,000 | 88.2 | Low | 45 | 39.69 |
| TOTAL | 22,655,000 | | | | 49.74 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | High | 5 | High | 5 | 25 |
| Adult Fish/Shellfish | Moderate | 3 | Moderate | 3 | 15 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Moderate | 3 | High | 5 | 15 |
| Marine Birds | High | 5 | High | 5 | 25 |
| Marine Turtles | None | 0 | Low | 1 | 0 |
| Marine Mammals | High | 5 | High | 5 | 25 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 120 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

These factors are not included in the calculations because of the difficulty of measuring their effects on the same basis as the effects of oil spills. In addition, information on the effects of some of these factors on habitats and biota throughout the entire OCS is not available. The effects of operational discharges, noise, habitat alteration, and air emissions will be considered further in other environmental analyses done of the 5-Year Program, such as the EIS on the Proposed Final Program, and in subsequent sale-specific EIS's. While the cumulative effects of these four factors may be more extensive and long lasting than the effects of a large oil spill, the Department of the Interior and other Federal, State, and local agencies have means available to control some of the adverse effects of these factors.

A. Methods

For the purposes of the calculations for the present analysis (Table I-3 and Appendix I-1), environmental sensitivity is defined in terms of the following variables:

1. the severity of damage resulting from the contact of spilled oil with various coastal and marine habitats and biota (this was designated as the persistence of oil in the 1982 analysis), and

2. the time required for the habitat or population to recover from the effects of contact with spilled oil.

The following assumptions are also included in the present environmental sensitivity analysis:

1. Spilled oil has not weathered significantly when it contacts the habitat or population. Weathering is the transformation of spilled oil through physical, chemical, or biological processes. Physical and chemical processes commence immediately after the spill. These processes include evaporation, spreading, emulsification, solution, and sedimentation. Evaporation is the predominant weathering process in the early stages of an oil spill. Many of the lighter molecular weight, toxic hydrocarbons evaporate from spilled oil within hours of a spill. Other weathering processes disperse the mass of the spilled oil and reduce its concentration. The impacts of spilled oil are reduced significantly by the effects of weathering. By eliminating the mitigating effects of weathering in the analysis of environmental sensitivity, the adverse effects of spilled oil, both toxicity and coating, are maximized. This assumption is conservative and provides an assessment of the most severe effects of spilled oil. However, use of this conservative assumption eliminates consideration of the distance between sensitive resources and potential oil fields or transportation routes. It also eliminates consideration of the mitigating effects of weathering on spilled oil moving from the site of production or transportation to the sensitive resource.

2. All of the biological populations in a planning area are contacted by spilled oil. Migratory species, which may inhabit the planning area for only a short period, are assumed to be present and contacted by spilled oil. Resources with seasonal sensitivities are assumed to be in their most sensitive stage when they are contacted by spilled oil. This assumption is extremely conservative and provides an assessment of the highest sensitivity of each resource and each planning area as a whole.



Performing an accurate analysis of environmental sensitivity requires a substantial amount of information on the spatial and temporal distribution of resources and the variations in their sensitivities to spilled oil. This is especially true where seasonal phenomena such as changes in productivity or the presence of migratory species would significantly increase or decrease the sensitivity of a planning area. If sufficient data were avialable, the environmental sensitivity of a planning area would be the sum of the sensitivities of its components integrated over time. This concept was reviewed during the preparation of the present analysis. It was abandoned because the minimum necessary information to conduct such an analysis is not available. Some information on some resources in some planning areas is avaiable, but the data are neither consistent nor available for all planning areas. As a result, the present analysis contains the simplifying assumptions described above. If adequate information were available, it would be possible to develop both expected and worst-case sensitivities. The reliance of the present analysis on conservative assumptions is, nonetheless, appropriate for the purpose of comparing the relative environmental sensitivities of the OCS planning areas.

B. Results

The resource-specific sensitivity evaluation is based on existing information. This required considerable professional judgment in interpreting the information and drawing conclusions to perform the relative rankings. As a result of this evaluation, the resource-specific sensitivity may differ in the different OCS regions. Where this occurs, this change results from differences in the estimated severity of the impact of spilled oil or in the estimated recovery time of the resource in response to differences in temperature, water depth, or other factors. As an example, in the present analysis, the environmental sensitivity of wetlands decreases from the colder planning areas to the warmer planning areas on the assumptions that oil would persist longer and that wetlands would require a longer period of time to recover in the colder planning areas. Estuaries and wetlands are rated moderately sensitive to spilled oil in the South Atlantic, the Straits of Florida, the Gulf of Mexico, and Southern California. In all other areas, estuaries and wetlands are given a rating of high sensitivity to spilled oil. The sensitivity rating for rocky beaches also changes as it is applied to the various OCS planning areas. In the Arctic (Hope Basin, Chukchi Sea, Beaufort Sea) planning areas, rocky beaches are given a low sensitivity. In most other areas, rocky beaches are given a moderate sensitivity. Sandy beaches are rated as having a low sensitivity in all planning areas.

Based upon the analyses of COPRDM (1981) and NRC (1985) most marine habitats are not very sensitive to spilled oil. These habitats are generally too deep to receive large quantities of oil from the ocean's surface. Most observations of the effects of oil spills have been directed to coastal habitats and biota. As a result, very little information is available on the effects of spilled oil on marine benthic habitats. The principal areas of sensitivity are shallow habitats such as beds of aquatic vegetation and coral reefs. Live hard bottom habitats may be sensitive in shallow areas. Unfortunately, information on the areal and depth distribution of these habitats is not available for most OCS planning areas.

For biota, the following categories were judged to have a high sensitivity to spilled oil: juvenile fish and shellfish, coastal and marine birds, marine mammals, and whales.

## IV. Relative Marine Productivity/Environmental Sensitivity

In the present analysis, the distributions and environmental sensitivities of the three ecological components within and/or on the adjacent coast of each OCS planning area are evaluated. These three components are coastal habitats, marine habitats, and biota. Coastal habitats include estuaries, wetlands, sandy beaches, and rocky beaches. The category of estuaries and wetlands includes lagoons and mangrove or forested wetlands. Marine habitats include submerged aquatic vegetation, coral reefs, live hard bottoms, submarine canyons, mud/sand bottoms, and the shelf break zone. Biota include phytoplankton, juvenile fish and shellfish, adult fish and shellfish, benthic communities of mud/sand bottoms, marine and coastal birds, marine turtles, marine mammals, and whales. The 1982 analysis included an extensive evaluation of fishery resources based on their commercial or subsistence use. This evaluation is not used in the present analysis because it does not add information about environmental sensitivity, only about the social value of the species. Table I-3 is an example of the calculations performed for each of the three ecological components. The calculations for each planning area are included in Appendix I-1.

### A. Methods

Calculation of the score for the environmental sensitivity of a single resource within one of the three components described above (for example, beaches within coastal habitats) requires: 1) a determination of resource size for habitats or relative abundance for biota, and 2) an evaluation of the sensitivity of the resource to spilled oil. Information on the resource size (habitats) or relative abundance (biota) used in the present analysis is presented in the tables and calcuations in Appendix I-1.

In the present analysis, the three ecological components are given equal theoretical importance. Each component is given a theoretical maximum score of 225 points. To attain or approach the theoretical maximum score, an ecological component must have a "high" concentration of highly-sensitive resources. In reality, no ecological component had sufficient concentrations to attain the theoretical maximum score.

The theoretical maximum score is determined by the calculation of the sensitivity of biota. Information on the distribution of biota in the



planning areas is normally expressed as population estimates or as standing stocks. These measures are significantly different from those for the coastal and marine habitats (see below). The biota are measured as discrete units and not as components of a larger measurable whole, such as the resources included in the coastal and marine habitats. This difference was accommodated by using professional judgment in interpreting available information on the abundance of the various categories of biota in the planning areas. The relative abundances were then rated as high, moderate, low, and none or negligible. The following numerical values were assigned to these ratings: high=5, moderate=3, low=1, and none or negligible=0. This information is included in the "Distribtuion of Resource" columns of the calculations (Table I-3 and Appendix I-1). Based upon the numerical values assigned to the sensitivity coefficients and to the relative abundances of biota, the maximum possible score for all biota in a planning area is 225 points.

The use of the theoretical maximum score assumes that each of the groups of biota evaluated in this analysis contributes to the sensitivity of the planning area. In none of the planning areas are all groups of biota present in high relative abundance. In fact, marine turtles do not occur in many planning areas. Their absence from a planning area or the absence of any other resource simply means that the resource does not contribute to the total score of the planning area. In the case of the marine turtles, their absence from most planning areas does not affect significantly the total scores of the planning areas.

The principal difference between the calculations for habitats and biota is the mathematical limit imposed by the use of percentages in the habitat calculations. In order to preserve the equal theoretical importance of the three ecological components, the numerical values for the sensitivity coefficients are increased to high=225, moderate=135, and low=45. These values are assigned only to preserve equal theoretical importance. The assignment of these values is not a statement that the sensitivities of coastal and marine habitats are 45 times greater than the sensitivities of marine biota. As a result of this change in the values attributed to the sensitivity coefficients for habitats, the theoretical maximum score for these components is also 225 points.

To obtain scores for coastal habitats, the various habitats were indentified for each planning area. Information on the size of coastal habitats is normally expressed in areal or linear units. For the calculations in Appendix I-1, sizes were expressed as percentages of the total length of the coast of the particular planning area. The sensitivities of the the various coastal habitats to spilled crude oil were determined. The percentage of the coast represented by the particular habitat was multiplied by the appropriate numerical value for the assigned sensitivity coefficient to produce a score for that habitat in the planning area. The sum of all of the scores of all coastal habitats in the planning area represents the evaluation of the sensitivity of the coast of the planning area to spilled oil. These calculations are illustrated in Table I-3.

The calculation for marine habitats in a planning area was similar to that for coastal habitats. In this instance, the percentage used in the calculation was the percentage of the planning area occupied by the particular habitat. An example of the calculation of the sensitivity of marine habitats is included in Table I-3. A major difference between the calculations for coastal and marine habitats is the lack of information on the extent of some marine habitats. In many of the calculations for marine habitats, only the areal extents of moderately and highly sensitive habitats were defined. However, since the remaining area has a low sensitivity to spilled oil (Appendix I-2), lack of data on the areal extent of these habitats does not affect the calculation of the score. The total score for the sensitivity of marine habitats includes the combined contribution of all low sensitivity habitats as well as the moderately and highly sensitive habitats.

Finally, the scores for each of the three ecological components in a planning area were added to produce a total score.

B. <u>Results</u>

The scores for each of the three ecological components (coastal habitats, marine habitats, and biota) of the OCS planning areas are displayed in Table I-4. The calculations of the indices are included in Appendix I-1.

For coastal habitats, the principal variables which affect the scores are the sensitivity ratings for estuaries and wetlands and rocky beaches.

As a result of the low sensitivity of most marine habitats in the OCS planning areas, the scores for these habitats are lower than those for coastal habitats and biota, and they do not discriminate markedly among the OCS planning areas. The highly sensitive coral reefs do not occupy sufficient area to affect the total scores for the South Atlantic and the Gulf of Mexico. The principal ecological component affecting the ratings for marine habitats is submerged vegetation.

The principal variables which affect the calculations for biota are their relative abundances in the various OCS planning areas. Information on relative abundance was collected from various OCS lease sale EIS's, draft chapters of the University of Maryland, Eastern Shore (UMES) study, studies sponsored by the OCS Environmental Studies Program, and other published oceanographic data. The presence of relatively high populations of juvenile fish and shellfish, coastal and marine birds, marine mammals, and whales, all of which are judged to have a high sensitivity to spilled oil, is the major factor supporting the high scores of many Alaskan planning areas. Many of these populations are transients and migrate through several of the Alaskan planning areas. These migratory populations are included in the abundance rating for each planning area where they occur.

The total scores for each planning area are displayed in Table I-5. Alaskan OCS planning areas occupy the extremes of this table. The Navarin Basin has the lowest total score because it lacks coastal habitats. The planning areas with the highest scores are Hope Basin, North Aleutian Basin, St. George Basin, and Norton Basin. Because much of the information used in the calculation of relative marine productivity and environmental sensitivity is qualitative, each assinged value in the calculation



TABLE I-4

Relative Marine Productivity and Environmental Sensitivity of the OCS Planning Areas by Ecological Component

| Coastal Habitats | | Marine Habitats | | Biota | |
|---|---|---|---|---|---|
| Planning Area | Score | Planning Area | Score | Planning Area | Score |
| Hope Basin | 181 | Straits of Florida | 55 | St. George Basin | 138 |
| North Aleutian Basin | 153 | Eastern Gulf of Mexico | 51 | North Aleutian Basin | 128 |
| Beaufort Sea | 142 | South Atlantic | 46 | Kodiak | 116 |
| Central Gulf of Mexico | 130 | Southern California | 46 | Norton Basin | 112 |
| Washington-Oregon | 127 | Central California | 46 | Hope Basin | 112 |
| Cook Inlet | 124 | North Atlantic | 45 | Shumagin | 110 |
| Norton Basin | 105 | Mid-Atlantic | 45 | Chukchi Sea | 100 |
| Shumagin | 105 | Central Gulf of Mexico | 45 | South Atlantic | 99 |
| Central California | 105 | Western Gulf of Mexico | 45 | Navarin Basin | 96 |
| St. George Basin | 104 | Northern California | 45 | Cook Inlet | 92 |
| Kodiak | 101 | Washington/Oregon | 45 | Southern California | 91 |
| Straits of Florida | 100 | Gulf of Alaska | 45 | Gulf of Alaska | 90 |
| Gulf of Alaska | 96 | Kodiak | 45 | Central California | 85 |
| Northern California | 92 | Cook Inlet | 45 | Northern California | 85 |
| Eastern Gulf of Mexico | 91 | Shumagin | 45 | Washington-Oregon | 84 |
| South Atlantic | 85 | North Aleutian Basin | 45 | Straits of Florida | 83 |
| North Atlantic | 83 | St. George Basin | 45 | Mid-Atlantic | 83 |
| Southern California | 82 | Navarin Basin | 45 | Western Gulf of Mexico | 81 |
| Mid-Atlantic | 70 | Norton Basin | 45 | North Atlantic | 81 |
| Chukchi Sea | 55 | Hope Basin | 45 | Central Gulf of Mexico | 79 |
| Western Gulf of Mexico | 54 | Chukchi Sea | 45 | Beaufort Sea | 70 |
| Navarin Basin | 0 | Beaufort Sea | 45 | Eastern Gulf of Mexico | 57 |

TABLE I-5

Relative Marine Productivity and Environmental Sensitivity of the OCS Planning Areas

| Planning Area | Total Score |
|---|---|
| Hope Basin | 338 |
| North Aleutian Basin | 326 |
| St. George Basin | 287 |
| Norton Basin | 262 |
| Kodiak | 262 |
| Cook Inlet | 261 |
| Shumagin | 260 |
| Beaufort Sea | 257 |
| Washington-Oregon | 256 |
| Central Gulf of Mexico | 254 |
| Straits of Florida | 238 |
| Central California | 236 |
| Gulf of Alaska | 231 |
| South Atlantic | 230 |
| Northern California | 222 |
| Southern California | 219 |
| North Atlantic | 209 |
| Chukchi Sea | 200 |
| Eastern Gulf of Mexico | 198 |
| Mid-Atlantic | 198 |
| Western Gulf of Mexico | 180 |
| Navarin Basin | 141 |



has some degree of uncertainty. Thus, the scores provided in Table I-5 should be viewed as estimates surrounded by some undefined variance. Scores with small differences between them should be viewed as relatively equal.

The results of this analysis are generally consistent with available information on the relative sensitivity of marine and coastal resources to spilled oil. The results are also consistent with the current concepts of relative sensitivity of coastal and marine habitats (COPRDM, 1981; NRC, 1985). This is most clearly shown for the Navarin Basin where coastal habitats are negligible. In addition, the presence of high populations of sensitive biota (coastal and marine birds, marine mammals, whales, juvenile fish and shellfish) are the major factors supporting the high total scores of the Alaskan planning areas. The ecological component which has the least effect on the total scores is marine habitats. This results from the assumption that spilled oil cannot be transported in significant amounts from the surface of the ocean to most benthic communities. The most sensitive marine habitats that could be affected are submerged vegetation and coral reefs, but these habitats do not occupy a significant portion of any planning area.

Several commenters on the Draft Proposed Program criticized the analysis of relative marine productivity and environmental sensitivity because of dissatisfaction with the results. In particular, the scores for marine habitats were criticized because the sensitivity of marine habitats in the various planning areas were given equal scores due to lack of data. However, this lack of data on areal extent of marine habitats is not considered critical because most marine habitats are judged to have low sensitivity to spilled oil and have been provided low sensitivity ratings.

The method used to generate total scores was modified to ascertain the significance of having equal scores for marine habitats in diverse planning areas. The ranking of planning areas as to their relative marine productivity and environmental sensitivity was determined both as a composite of the individual scores for coastal habitats, marine habitats, and biota (Table I-5) and for coastal habitats and biota without marine habitats (Table I-6). The final order of planning areas is not changed significantly whether marine habitats are considered or not. As stated previously, scores with small differences between them should be viewed as relatively equal. Thus, the model is not sensitive to the lack of data on areal extent of low-sensitivity marine habitats.

The results of this analysis should not be construed as indicating the level of impacts expected as a result of OCS development. In this analysis, sensitivity is determined from the likely response of the resource to the environmental perturbation without consideration of risk, likelihood of adverse impact, or vulnerability. Thus, the sensitivity ratings represent a conservative analysis. Additional factors would need to be considered to determine the expected level of impacts in a planning area from OCS oil and gas operations. These factors include the projected amount of hydrocarbon resources, their probable location within the planning area, the number and trajectory of hypothetical oil spills, and the location of possible spill sites, among others.

TABLE I-6

Relative Marine Productivity and Environmental Sensitivity of the OCS Planning Areas Calculated as the Sum of the Scores for Coastal Habitats and Biota

| Planning Area | Score |
|---|---|
| Hope Basin | 293 |
| North Aleutian Basin | 281 |
| St. George Basin | 242 |
| Norton Basin | 217 |
| Kodiak | 217 |
| Cook Inlet | 216 |
| Shumagin | 215 |
| Beaufort Sea | 212 |
| Washington-Oregon | 211 |
| Central Gulf of Mexico | 209 |
| Central California | 190 |
| Gulf of Alaska | 186 |
| South Atlantic | 184 |
| Straits of Florida | 183 |
| Northern California | 177 |
| Southern California | 173 |
| North Atlantic | 164 |
| Chukchi Sea | 155 |
| Mid-Atlantic | 153 |
| Eastern Gulf of Mexico | 147 |
| Western Gulf of Mexico | 135 |
| Navarin Basin | 96 |



A high total score or the presence of many sensitive resources in a planning area does not necessarily imply a high level of adverse effects from OCS development. Even those areas ranked with relatively low scores possess sensitive resources which will require consideration of specific environmental impacts at the sale stage and evaluation to determine the need for special protective measures.

The present analysis of relative marine productivity and environmental sensitivity is one step in a continuing process of environmental assessment. The concepts presented in the present analysis will be evaluated and discussed in greater detail in the EIS for the proposed leasing program, and further analysis of environmental information will occur in subsequent lease-sale specific EIS's.

In relation to the 1982 analysis, the present analysis provides the basis for incorporating into a systematic calculation new information on the distribution of resources and their sensitivities to spilled oil. The present analysis still contains some of the assumptions and judgments contained in the 1982 analysis. Many of these may be replaced by quantitative information by the time the next relative marine productivity and environmental sensitivity analysis must be performed. The OCS Environmental Studies Program is sponsoring several studies which will provide relevant information for the next analysis.

C. Background Evaluations

An extensive body of literature was reviewed as background to the environmental sensitivity values assigned to the planning area calculations included in Appendix I-1. This material was summarized in Appendix I-2 of the Proposed Program. Appendix I-2 included an extensive bibliography of the materials consulted prior to assigning relative values to the planning areas. This material summarized available information on the environmental sensitivity of specific habitats by categories identified as estuaries and wetlands, beaches, submerged aquatic vegetation, submarine canyons, shelf break zone, coral reefs, and live hard bottoms. The sensitivity of different types of marine biota was assessed by categories identified as plankton, mud/sand benthos, fish and shellfish, marine birds, coastal birds, marine turtles, and marine mammals. Each of these habitats and biotic components was evaluated for its sensitivity to accidental contact with crude oil. Such sensitivity varies widely in response to factors such as period of exposure, density and chemical composition of the oil, amount of weathering prior to contact, and other factors.

The environmental sensitivity of various habitats and organisms was also considered with respect to other impact-producing factors. These factors (listed below) were not used in the calculation of environmental sensitivity for the reasons given on page I-8 of this analysis.

1. Drilling discharges (muds, cuttings, and produced waters).
2. Noise generated by OCS activities.
3. Habitat alteration from the installation of OCS facilities.
4. Air emissions from OCS operations.

The potential effects of these factors are singularly more limited in extent than the potential effects of a large oil spill. However, the cumulative effects of these factors may be more extensive and long-lasting than the effects of a large spill. Several means are available to mitigate or lessen the adverse effects of these factors. As a result, spilled oil was the factor of greatest concern in the present analysis.



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* Study sponsored by the OCS Environmental Studies Program

# APPENDIX I-1

# RELATIVE MARINE PRODUCTIVITY AND ENVIRONMENTAL SENSITIVITY

# OIL SPILLS

# CALCULATIONS

Proposed Final Program:
5-Year Outer Continental Shelf Oil and Gas Leasing Program
for Mid-1987 through Mid-1991

## Relative Marine Productivity/Environmental Sensitivity Analysis

### Oil Spills

Planning Area: North Atlantic

Total Score: 209

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 25 | 5.8 | High | 225 | 13.1 |
| Sandy Beaches | 275 | 63.6 | Low | 45 | 28.6 |
| Rocky Beaches | 133 | 30.6 | Moderate | 135 | 41.3 |
| TOTAL | 433 | | | | 83.0 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | Negligible | 0.00 | High | 225 | 0.00 |
| Submarine Canyons | 1,290,000 | 2.55 | Low | 45 | 1.15 |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | 6,496,000 | 12.8 | Low | 45 | 5.77 |
| Mud/Sand Bottom | | | Low | 45 | 38.08 |
| TOTAL | 50,600,000 | | | | 45.00 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | High | 5 | High | 5 | 25 |
| Adult Fish/Shellfish | High | 5 | Moderate | 3 | 15 |
| Mud/Sand Benthos | Moderate | 3 | Low | 1 | 3 |
| Coastal Birds | Moderate | 3 | High | 5 | 15 |
| Marine Birds | Low | 1 | High | 5 | 5 |
| Marine Turtles | Low | 1 | Moderate | 3 | 3 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 81 |

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.



## Relative Marine Productivity/Environmental Sensitivity Analysis

### Oil Spills

Planning Area: Mid-Atlantic

Total Score: 198

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 78 | 12.7 | High | 225 | 28.6 |
| Sandy Beaches | 525 | 84.9 | Low | 45 | 38.2 |
| Rocky Beaches | 15 | 2.4 | Moderate | 135 | 3.2 |
| TOTAL | 618 | | | | 70.0 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | Negligible | 0.00 | High | 225 | 0.00 |
| Submarine Canyons | 600,000 | 0.73 | Low | 45 | 0.33 |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | Negligible | 0.00 | Low | 45 | 0.00 |
| Shelf Break Zone | 783,000 | 0.95 | Low | 45 | 0.43 |
| Mud/Sand Bottom | 80,817,000 | 98.3 | Low | 45 | 44.24 |
| TOTAL | 82,200,000 | | | | 45.00 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | High | 5 | High | 5 | 25 |
| Adult Fish/Shellfish | Moderate | 3 | Moderate | 3 | 9 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Moderate | 3 | High | 5 | 15 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | Moderate | 3 | Low | 1 | 3 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 83 |

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: South Atlantic — Total Score: 230

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 321 | 44.1 | Moderate | 135 | 59.5 |
| Sandy Beaches | 406 | 55.9 | Low | 45 | 25.2 |
| Rocky Beaches | Negligible | 0.0 | Low | 45 | 0.0 |
| TOTAL | 727 | | | | 84.7 |

| | | | | | |
|---|---|---|---|---|---|
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 21,000 | 0.02 | High | 225 | 0.05 |
| Submarine Canyons | 75,000 | 0.07 | Low | 45 | 0.03 |
| Coral Reefs | 481,000 | 0.45 | High | 225 | 1.01 |
| Hard Bottoms | 1,852,000 | 1.75 | Low | 45 | 0.79 |
| Shelf Break Zone | 3,826,000 | 3.62 | Low | 45 | 1.63 |
| Mud/Sand Bottom | 99,545,000 | 94.1 | Low | 45 | 42.53 |
| TOTAL | 105,800,000 | | | | 45.86 |

| | | | | | |
|---|---|---|---|---|---|
| Biota | | | | | |
| Phytoplankton | Moderate | 3 | Low | 1 | 3 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | High | 5 | Moderate | 3 | 15 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | High | 5 | High | 5 | 25 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | High | 5 | Moderate | 3 | 15 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 99 |

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.



Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Straits of Florida — Total Score: 238

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 270 | 60.7 | Moderate | 135 | 81.9 |
| Sandy Beaches | 175 | 39.3 | Low | 45 | 17.7 |
| Rocky Beaches | Negligible | 0.0 | Low | 45 | 0.0 |
| TOTAL | 445 | | | | 99.6 |

| | | | | | |
|---|---|---|---|---|---|
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 123,000 | 1.24 | High | 225 | 2.79 |
| Submarine Canyons | Negligible | 0.00 | Low | 45 | 0.00 |
| Coral Reefs | 443,500 | 4.46 | High | 225 | 10.03 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 42.43 |
| TOTAL | 9,940,000 | | | | 55.25 |

| | | | | | |
|---|---|---|---|---|---|
| Biota | | | | | |
| Phytoplankton | Moderate | 3 | Low | 1 | 3 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Moderate | 3 | Moderate | 3 | 9 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Moderate | 3 | High | 5 | 15 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | High | 5 | Moderate | 3 | 15 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 83 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Eastern Gulf of Mexico | Total Score: 198

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 346 | 50.6 | Moderate | 135 | 68.3 |
| Sandy Beaches | 338 | 49.4 | Low | 45 | 22.2 |
| Rocky Beaches | Negligible | 0.0 | Low | 45 | 0.0 |
| TOTAL | 684 | | | | 90.5 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 2,030,000 | 2.82 | High | 225 | 6.34 |
| Submarine Canyons | Negligible | 0.0 | Low | 45 | 0.00 |
| Coral Reefs | 232,500 | 0.32 | High | 225 | 0.73 |
| Hard Bottoms | 10,874,000 | 15.1 | Low | 45 | 6.80 |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 36.79 |
| TOTAL | 72,000,000 | | | | 50.66 |
| Biota | | | | | |
| Phytoplankton | Low | 1 | Low | 1 | 1 |
| Juvenile Fish/Shellfish | Low | 1 | High | 5 | 5 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Moderate | 3 | Low | 1 | 3 |
| Coastal Birds | Moderate | 3 | High | 5 | 15 |
| Marine Birds | Low | 1 | High | 5 | 5 |
| Marine Turtles | High | 5 | Moderate | 3 | 15 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 57 |

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.



Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Central Gulf of Mexico | Total Score: 254

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 468 | 94.7 | Moderate | 135 | 127.9 |
| Sandy Beaches | 26 | 5.4 | Low | 45 | 2.4 |
| Rocky Beaches | Negligible | 0.0 | Low | 45 | 0.00 |
| TOTAL | 494 | | | | 130.3 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 71,000 | 0.16 | High | 225 | 0.36 |
| Submarine Canyons | Negligible | 0.00 | Low | 45 | 0.00 |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | 21,000 | 0.05 | Low | 45 | 0.03 |
| Shelf Break Zone | 1,716,000 | 3.80 | Low | 45 | 1.71 |
| Mud/Sand Bottom | 43,292,000 | 96.0 | Low | 45 | 43.20 |
| TOTAL | 45,100,000 | | | | 45.29 |
| Biota | | | | | |
| Phytoplankton | Low | 1 | Low | 1 | 1 |
| Juvenile Fish/Shellfish | High | 5 | High | 5 | 25 |
| Adult Fish/Shellfish | High | 5 | Moderate | 3 | 15 |
| Mud/Sand Benthos | Moderate | 3 | Low | 1 | 3 |
| Coastal Birds | Moderate | 3 | High | 5 | 15 |
| Marine Birds | Low | 1 | High | 5 | 5 |
| Marine Turtles | High | 5 | Low | 1 | 5 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 79 |

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

## Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Western Gulf of Mexico    Total Score: 180

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 37 | 10.2 | Moderate | 135 | 13.8 |
| Sandy Beaches | 330 | 89.8 | Low | 45 | 40.4 |
| Rocky Beaches | Negligible | 0.0 | Low | 45 | 0.0 |
| TOTAL | 367 | | | | 54.2 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | Negligible | 0.00 | High | 225 | 0.0 |
| Submarine Canyons | Negligible | 0.00 | Low | 45 | 0.0 |
| Coral Reefs | 5,600 | 0.02 | High | 225 | 0.05 |
| Hard Bottoms | 52,000 | 0.15 | Low | 45 | 0.07 |
| Shelf Break Zone | 1,607,000 | 4.55 | Low | 45 | 2.05 |
| Mud/Sand Bottom | 33,635,400 | 95.3 | Low | 45 | 42.89 |
| TOTAL | 35,300,000 | | | | 45.06 |
| Biota | | | | | |
| Phytoplankton | Low | 1 | Low | 1 | 1 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Moderate | 3 | Moderate | 3 | 9 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | High | 5 | High | 5 | 25 |
| Marine Birds | Low | 1 | High | 5 | 5 |
| Marine Turtles | High | 5 | Moderate | 3 | 15 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 81 |

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.



## Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Southern California    Total Score: 219

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 4 | 0.6 | High | 225 | 1.4 |
| Sandy Beaches | 424 | 59.6 | Low | 45 | 26.8 |
| Rocky Beaches | 283 | 39.8 | Moderate | 135 | 53.7 |
| TOTAL | 711 | | | | 81.9 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 128,410 | 0.43 | High | 225 | 0.97 |
| Submarine Canyons | | | Low | 45 | |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 44.81 |
| TOTAL | 29,900,000 | | | | 45.78 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Moderate | 3 | Moderate | 3 | 9 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Moderate | 3 | High | 5 | 15 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | Low | 1 | Low | 1 | 1 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 91 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Central California

Total Score: 236

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 5 | 1.6 | High | 225 | 3.6 |
| Sandy Beaches | 109 | 35.0 | Low | 45 | 15.8 |
| Rocky Beaches | 197 | 63.3 | Moderate | 135 | 85.5 |
| TOTAL | 311 | | | | 104.9 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 21,000 | 0.14 | High | 225 | 0.31 |
| Submarine Canyons | 248,000 | 1.65 | Low | 45 | 0.74 |
| Coral Reefs | 85,000 | 0.57 | High | 225 | 1.28 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 43.94 |
| TOTAL | 15,000,000 | | | | 46.27 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Moderate | 3 | High | 5 | 15 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | Low | 1 | Low | 1 | 1 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 85 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.



Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Northern California

Total Score: 222

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 9 | 3.7 | High | 225 | 8.3 |
| Sandy Beaches | 126 | 51.4 | Low | 45 | 23.1 |
| Rocky Beaches | 110 | 44.9 | Moderate | 135 | 60.6 |
| TOTAL | 245 | | | | 92.0 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 7,000 | 0.02 | High | 225 | 0.05 |
| Submarine Canyons | 305,000 | 1.07 | Low | 45 | 0.48 |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 44.51 |
| TOTAL | 28,500,000 | | | | 45.04 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Moderate | 3 | High | 5 | 15 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | Low | 1 | Low | 1 | 1 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 85 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Washington-Oregon Total Score: 256

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 45 | 10.0 | High | 225 | 22.5 |
| Sandy Beaches | 86 | 19.0 | Low | 45 | 8.6 |
| Rocky Beaches | 322 | 71.0 | Moderate | 135 | 95.9 |
| TOTAL | 453 | | | | 127.0 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | | | Moderate | 135 | |
| Submarine Canyons | | | Low | 45 | |
| Coral Reefs | | | High | 225 | |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | |
| TOTAL | 47,900,000 | | | | 45 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Moderate | 3 | High | 5 | 15 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | Negligible | 0 | Low | 1 | 0 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 84 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.



Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Gulf of Alaska Total Score: 231

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | | 11.2 | High | 225 | 25.2 |
| Sandy Beaches | | 54.4 | Low | 45 | 24.5 |
| Rocky Beaches | | 34.5 | Moderate | 135 | 46.6 |
| TOTAL | | | | | 96.3 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | | | Moderate | 135 | |
| Submarine Canyons | | | Low | 45 | |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 45.00 |
| TOTAL | 132,300,000 | | | | 45.00 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Moderate | 3 | Moderate | 3 | 9 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Low | 1 | High | 5 | 5 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | None | 0 | Low | 1 | 0 |
| Marine Mammals | High | 5 | High | 5 | 25 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 90 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

## Relative Marine Productivity/Environmental Sensitivity Analysis

### Oil Spills

Planning Area: Kodiak — Total Score: 262

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | | 1.6 | High | 225 | 3.6 |
| Sandy Beaches | | 39.5 | Low | 45 | 17.8 |
| Rocky Beaches | | 58.9 | Moderate | 135 | 79.5 |
| TOTAL | | | | | 100.9 |

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | | | Moderate | 135 | |
| Submarine Canyons | | | Low | 45 | |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 45.00 |
| TOTAL | 89,000,000 | | | | 45.00 |

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | High | 5 | Moderate | 3 | 15 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | High | 5 | High | 5 | 25 |
| Marine Birds | High | 5 | High | 5 | 25 |
| Marine Turtles | None | 0 | Low | 1 | 0 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 116 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.



## Relative Marine Productivity/Environmental Sensitivity Analysis

### Oil Spills

Planning Area: Cook Inlet — Total Score: 261

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 215 | 14.1 | High | 225 | 31.7 |
| Sandy Beaches | 396 | 26.0 | Low | 45 | 11.7 |
| Rocky Beaches | 913 | 59.9 | Moderate | 135 | 80.9 |
| TOTAL | 1524 | | | | 124.3 |

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | | | Moderate | 135 | |
| Submarine Canyons | Negligible | 0.00 | Low | 45 | 0.00 |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 45.00 |
| TOTAL | 5,300,000 | | | | 45.00 |

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Moderate | 3 | Moderate | 3 | 9 |
| Mud/Sand Benthos | Low | 1 | Moderate | 3 | 3 |
| Coastal Birds | High | 5 | High | 5 | 25 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | None | 0 | Low | 1 | 0 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 92 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Shumagin — Total Score: 260

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | | 1.0 | High | 225 | 2.3 |
| Sandy Beaches | | 34.0 | Low | 45 | 15.3 |
| Rocky Beaches | | 65.0 | Moderate | 135 | 87.8 |
| TOTAL | | | | | 105.4 |

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | | | Moderate | 135 | |
| Submarine Canyons | | | Low | 45 | |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 45.00 |
| TOTAL | 83,000,000 | | | | 45.00 |

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Moderate | 3 | Moderate | 3 | 9 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | High | 5 | High | 5 | 25 |
| Marine Birds | High | 5 | High | 5 | 25 |
| Marine Turtles | None | 0 | Low | 1 | 0 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 110 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.



Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: North Aleutian Basin — Total Score: 326

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | | 32.6 | High | 225 | 73.4 |
| Sandy Beaches | | 13.1 | Low | 45 | 5.9 |
| Rocky Beaches | | 54.3 | Moderate | 135 | 73.3 |
| TOTAL | | | | | 152.6 |

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | | | Moderate | 135 | |
| Submarine Canyons | Negligible | 0.00 | Low | 45 | 0.00 |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | Negligible | 0.00 | Low | 45 | 0.00 |
| Mud/Sand Bottom | | | Low | 45 | 45.00 |
| TOTAL | 32,500,000 | | | | 45.00 |

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | High | 5 | High | 5 | 25 |
| Adult Fish/Shellfish | High | 5 | Moderate | 3 | 15 |
| Mud/Sand Benthos | Moderate | 3 | Low | 1 | 3 |
| Coastal Birds | High | 5 | High | 5 | 25 |
| Marine Birds | High | 5 | High | 5 | 25 |
| Marine Turtles | None | 0 | Low | 1 | 0 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 128 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: St. George Basin — Total Score: 287

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | | 0.3 | High | 225 | 0.7 |
| Sandy Beaches | | 26.3 | Low | 45 | 11.9 |
| Rocky Beaches | | 67.5 | Moderate | 135 | 91.1 |
| TOTAL | | | | | 103.7 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | | | Moderate | 135 | |
| Submarine Canyons | | | Low | 45 | |
| Coral Reefs | None | 0.0 | High | 225 | |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 45.00 |
| TOTAL | 70,200,000 | | | | 45.00 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | High | 5 | High | 5 | 25 |
| Adult Fish/Shellfish | High | 5 | Moderate | 3 | 15 |
| Mud/Sand Benthos | Moderate | 3 | Low | 1 | 3 |
| Coastal Birds | Moderate | 3 | High | 5 | 15 |
| Marine Birds | High | 5 | High | 5 | 25 |
| Marine Turtles | None | 0 | Low | 1 | 0 |
| Marine Mammals | High | 5 | High | 5 | 25 |
| Whales | High | 5 | High | 5 | 25 |
| TOTAL | | | | | 138 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.



Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Navarin Basin — Total Score: 141

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | None | | High | 225 | 0.0 |
| Sandy Beaches | None | | Low | 45 | 0.0 |
| Rocky Beaches | None | | Moderate | 135 | 0.0 |
| TOTAL | | | | | 0.0 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | Negligible | 0.00 | Moderate | 135 | 0.0 |
| Submarine Canyons | | | Low | 45 | |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.0 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | |
| TOTAL | 37,100,000 | | | | 45.0 |
| Biota | | | | | |
| Phytoplankton | Moderate | 3 | Low | 1 | 3 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | High | 5 | Moderate | 3 | 15 |
| Mud/Sand Benthos | Moderate | 3 | Low | 1 | 3 |
| Coastal Birds | Low | 1 | High | 5 | 5 |
| Marine Birds | High | 5 | High | 5 | 25 |
| Marine Turtles | None | 0 | Low | 1 | 0 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 96 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Norton Basin

Total Score: 262

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 623 | 33.4 | High | 225 | 75.2 |
| Sandy Beaches | 382 | 20.5 | Low | 45 | 9.3 |
| Rocky Beaches | 859 | 46.1 | Low | 45 | 20.7 |
| TOTAL | 1864 | | | | 105.2 |

| | | | | | |
|---|---|---|---|---|---|
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | | | High | 225 | |
| Submarine Canyons | Negligible | 0.00 | Low | 45 | 0.00 |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 45.00 |
| TOTAL | 25,000,000 | | | | 45.00 |

| | | | | | |
|---|---|---|---|---|---|
| Biota | | | | | |
| Phytoplankton | Moderate | 3 | Low | 1 | 3 |
| Juvenile Fish/Shellfish | Low | 1 | High | 5 | 5 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | High | 5 | High | 5 | 25 |
| Marine Birds | High | 5 | High | 5 | 25 |
| Marine Turtles | None | 0 | Low | 1 | 0 |
| Marine Mammals | High | 5 | High | 5 | 25 |
| Whales | High | 5 | High | 5 | 25 |
| TOTAL | | | | | 112 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.



Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Hope Basin

Total Score: 338

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | | 75.7 | High | 225 | 170.3 |
| Sandy Beaches | | 4.9 | Low | 45 | 2.2 |
| Rocky Beaches | | 19.5 | Low | 45 | 8.8 |
| TOTAL | | | | | 181.3 |

| | | | | | |
|---|---|---|---|---|---|
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | | | Moderate | 135 | |
| Submarine Canyons | | | Low | 45 | |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 45.00 |
| TOTAL | 11,800,000 | | | | 45.00 |

| | | | | | |
|---|---|---|---|---|---|
| Biota | | | | | |
| Phytoplankton | Low | 1 | Low | 1 | 1 |
| Juvenile Fish/Shellfish | Low | 1 | High | 5 | 5 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Moderate | 3 | Low | 1 | 3 |
| Coastal Birds | High | 5 | High | 5 | 25 |
| Marine Birds | High | 5 | High | 5 | 25 |
| Marine Turtles | None | 0 | Low | 1 | 0 |
| Marine Mammals | High | 5 | High | 5 | 25 |
| Whales | High | 5 | High | 5 | 25 |
| TOTAL | | | | | 112 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

## Relative Marine Productivity/Environmental Sensitivity Analysis

### Oil Spills

Planning Area: Chukchi Sea

Total Score: 200

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | | 5.5 | High | 225 | 12.4 |
| Sandy Beaches | | 74.4 | Low | 45 | 33.5 |
| Rocky Beaches | | 20.2 | Low | 45 | 9.1 |
| TOTAL | | | | | 55.0 |

| | | | | | |
|---|---|---|---|---|---|
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | | | Moderate | 135 | |
| Submarine Canyons | | | Low | 45 | |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 45.00 |
| TOTAL | 29,500,000 | | | | 45.00 |

| | | | | | |
|---|---|---|---|---|---|
| Biota | | | | | |
| Phytoplankton | Low | 1 | Low | 1 | 1 |
| Juvenile Fish/Shellfish | Low | 1 | High | 5 | 5 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | High | 5 | High | 5 | 25 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | None | 0 | Low | 1 | 0 |
| Marine Mammals | High | 5 | High | 5 | 25 |
| Whales | High | 5 | High | 5 | 25 |
| TOTAL | | | | | 100 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.



## Relative Marine Productivity/Environmental Sensitivity Analysis

### Oil Spills

Planning Area: Beaufort Sea

Total Score: 257

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | | 52.9 | High | 225 | 119.0 |
| Sandy Beaches | | 46.9 | Low | 45 | 21.1 |
| Rocky Beaches | | 3.0 | Low | 45 | 1.4 |
| TOTAL | | | | | 141.5 |

| | | | | | |
|---|---|---|---|---|---|
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | | | Moderate | 135 | |
| Submarine Canyons | | | Low | 45 | |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 45.00 |
| TOTAL | 49,400,000 | | | | 45.00 |

| | | | | | |
|---|---|---|---|---|---|
| Biota | | | | | |
| Phytoplankton | Low | 1 | Low | 1 | 1 |
| Juvenile Fish/Shellfish | Low | 1 | High | 5 | 5 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | High | 5 | High | 5 | 25 |
| Marine Birds | Low | 1 | High | 5 | 5 |
| Marine Turtles | None | 0 | Low | 1 | 0 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 70 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Appendix I-2

BACKGROUND PAPERS ON ENVIRONMENTAL SENSITIVITY

# BACKGROUND PAPERS ON ENVIRONMENTAL SENSITIVITY

## CONTENTS





## Sensitivity of Coastal Habitats to Oil Spills

Several methods have been developed to rank various shoreline types in terms of their sensitivity to oil contamination. Owens (1971) defined nine shoreline types in terms of their sensitivity to oil spills and suggested the basic relationship between shoreline type, oil persistence, and biological sensitivity. Hayes, Brown, and Michel (1976) used the longevity of oil in different environments in the absence of cleanup effects to define 10 shoreline types in terms of an oil susceptibility index. This approach was modified by Ruby (1977), Gundlach and Hayes (1978), Ruby and Hayes (1978), and Michel, Hayes, and Brown (1978) to include some biological considerations. This modified approach was designated the "Oil Spill Vulnerability Index." Nummedal (1980) used oil retention potential to define eight shoreline types in his study of the Beaufort Sea coast of Alaska. Gundlach, Getter, and Hayes (1980) expanded the vulnerability index of Gundlach and Hayes (1978) to include locations and seasonal use information for sensitive biological resources. This information was portrayed on maps, and the index was called the "Environmental Sensitivity Index." Woodward-Clyde Consultants (1982), in a study conducted for the Minerals Management Service, developed "oil residence and geological sensitivity indexes" for central and northern California coastal marine habitats. The biological sensitivity index included resources that are permanent within the study area, that spend most of their time there, or that are dependent upon the area for some part of their life history. The approach of using two separate indexes instead of a single index based primarily on shoreline type was found to yield more valuable information with respect to potential effects of spilled oil.

### Estuaries and Wetlands

Estuaries are semienclosed coastal bodies of water having free connection with the open sea, and within which seawater is measurably diluted with fresh water (Pritchard, 1967). Estuaries and their associated wetlands are characterized by daily or seasonal shifts in salinity, temperature, and desiccation, such that estuarine plants and animals live at or near the limits of their tolerances (Malins, 1977a). In this stressful environment, species diversity is more limited than that in more stable environments. However, the estuarine ecosystem is highly productive, with large numbers of individual animals. Total biomass is relatively high (McLusky, 1981). Within an estuary, wetlands are an important feature. They provide shelter, specialized habitat, and most importantly, they are a source of energy to estuarine consumers (Malins, 1977a).

Oil in the estuarine environment is not a uniform or stable pollutant. Crude oil behaves differently and has different environmental effects from refined products. Also, the composition of crude oil varies greatly from field to field. As soon as oil is released in water, it undergoes weathering processes such as spreading, evaporation, emulsification, photo- and chemical oxidation, biological degradation, and agglomeration and sinking. Of these processes, biodegradation is particularly important in wetlands and estuaries because of the actions of bacteria, which are more abundant in these areas than in marine waters (Lee, 1977). The rate of weathering processes generally increases with increasing ambient temperature. These processes can change the initial oil slick to suspend droplets, mousse, or tarballs (Royal Commission on Environmental Pollution, 1981). Oil pollution causes both physical and toxic effects in plants and animals. Generally, the lighter hydrocarbons in oil are the most toxic but are also the first fractions to weather from oil. Weathering time varies from hours to weeks depending upon the molecular weight of the fraction. Thus, the effects of oil on estuaries and wetlands vary considerably with the type of oil encountered and the degree of weathering it has undergone.

Oil droplets will encounter suspended particulate material in estuaries and will become adsorbed on oleophilic particles and detritus and sink to the bottom. Tarballs may also sink to the bottom or become stranded along the estuarine shoreline along with floating oil and mousse. Exposed intertidal sandy or muddy substrate may be coated with floating oil, too. Depending upon the grain size of the substrate, oil may be absorbed, adsorbed, or refloated on rising tides. Generally, oil does not penetrate or adhere to finer-grained sediments. This was observed in the Metula and Urquiola oil spills (Ruby, 1977). Penetration of sediment can vary from a few inches to nearly 2 feet (Blumer et al., 1971).

Stranded and sunken oil continues to degrade, varying with climate, availability of oxygen, and microbial activity (Malins, 1977b). The persistence of spilled oil in estuaries and wetlands varies considerably. Oil tends to last longer and to degrade more slowly in low-energy, protected environments (Rashid, 1974). Wetlands and sheltered tidal flats are particularly vulnerable to the long lasting effects of oil (Ruby 1977; Hahn, 1977; Gundlach et al., 1981; Gundlach, 1980). Crude oil that was stranded in wetlands from the Metula oil spill in 1974 in the cool climate of the Straits of Magellan has remained nearly unchanged and may persist for 100 years (Gundlach, 1980). In contrast, crude oil from the 1978 Amoco Cadiz spill in marshes along the Brittany coast degraded noticeably during a 3-year period, and the surface of the tidal flats was free of oil in less than 1 year (Gundlach et al., 1981). For further comparison, a spill of No. 6 fuel oil in the Chesapeake Bay in 1976 was mostly gone in a single season (Hershner and Moore, 1977). Persistence of oil in estuarine open waters and exposed tidal flats is less than in wetlands, but longer than in high-energy beaches and coasts. In the Amoco Cadiz spill, Metula spill, Torrey Canyon spill in England, and the Urquiola Spill in Spain, oil was gone from surface waters and most intertidal beds within 1 year (Ruby, 1977; Gundlach et al., 1981; Adams et al., 1984; Gundlach et al., 1978; Smith, 1970). However, residence time of oil absorbed into benthic substrates has been observed to last as long as 7 years (Blumer et al., 1971; Gundlach et al., 1981; Hayes, Gundlach, and Getter, 1980).

Estuarine biota are affected by oil through physical effects and toxic effects. The physical effects include coating of plants and animals so that respiratory and feeding structures are fouled, and smothering or starvation occurs. Substrate may be coated by oil so that oxygen cannot reach the root systems of vascular plants, or substrate may be fouled so that plants and animals can no longer utilize or colonize it. Oil coating will kill green leaves of wetland plants by blocking out sunlight or through toxic effects as



has been observed in mangroves (Odum and Johannes, 1975). Oil floating in shallow water cuts off sunlight to vascular plants and algae, and its lower albedo may raise water temperature and reduce dissolved oxygen (Odum and Johannes, 1975).

The toxic effects of oil can be lethal or sublethal. Cell death and animal mortality may result in lower animals. Higher animals may receive skin burns from contact with oil or may suffer various organ and glandular necroses resulting in death. Sublethal effects include reduced growth, altered feeding behavior, altered reproductive behavior, and lower reproductive success.

Within the estuary, adult and juvenile fish can generally sense oil and are mobile enough to avoid contact with it (Royal Commission on Environmental Pollution, 1981). However, planktonic fish eggs and fish larvae are highly sensitive to even small quantities of oil and may be killed by concentrations as low as $10^{-5}$ ml/liter of very toxic hydrocarbons (Perkins, 1974). Because of the number of variables involved, it is impossible to predict expected hydrocarbon levels in an estuary that might result from a large oil spill, but it would be expected to be higher than $10^{-5}$ ml/liter. Spawning and migration behavior may be affected in fish. Salmon have been observed to avoid oil-contaminated water. In open water, this is advantageous; but when the oil is in estuaries and streams, spawning salmon may be disrupted; and lower escapements result (Minerals Management Service, 1984).

Benthic plants and animals are highly sensitive to toxic hydrocarbons as in fresh crude and refined oil products, but responses of species to weathered oil vary. Some algae-grazing winkles, limpets, and chitons are killed by fresh crude but can be unaffected even though completely covered with weathered oil (Nelson-Smith, 1973). Likewise, the mortality rates in many bivalves and marine worms vary considerably with the species and the type of oil contacted. However, other grazing mollusks, like abalone, have a high mortality response to oil pollution (Nelson-Smith, 1973). Echinoderms, such as urchins and starfish, are also very sensitive to any oil pollution. Filter feeding animals, such as oysters, clams, mussels, and barnacles, may ingest oil-coated detritus, but effects vary with the toxicity of the oil. Some mollusks smothered with weathered oil have metabolized the oil and survived (Royal Commission on Environmental Pollution, 1981). Crustaceans, such as crabs and lobsters, are highly mobile and can avoid contact with small quantities of oil, although some affinity for kerosene has been observed in lobsters (Royal Commission on Environmental Pollution, 1981). However, contact with toxic hydrocarbons is fatal to many crustaceans. Larval forms of benthic invertebrates are all highly sensitive to oil, and some, such as crab larvae that float near the surface, are particularly susceptible to contact.

The responses of aquatic plants to oil pollution vary between species and with different types of oil. Some macroalgae, suck as kelp and other brown algae, are covered with mucilagenous slimes that keep them from being covered with oil, but they are sensitive to contact with toxic, light hydrocarbons. In contrast, red algae and many sea grasses are sensitive to any oil pollution (Nelson-Smith, 1973). Blue-green microalgae that cover intertidal mudflats are oleophilic and easily smothered by oil (Royal Commission on Environmental Pollution, 1981).

Oil pollution in salt marshes has been well studied (Baker, 1971). Important factors which affect damage to marshes are the amount and type of oil, plant species, time of year, and cleanup treatment. Single, moderate-sized oil spills have marginal effects on wetland plants (Hershner and Moore, 1977; Baker, 1971). However, multiple spills or large spills can destroy most or all emergent growth (Hayes et al., 1980). Generally, fresh oil has been observed to be more toxic than weathered oil to marsh plants (Baker, 1971). However, one study has shown that the immediate effects of spilled oil on Spartina marsh were the same for fresh as weathered oil (Bender et al., 1977). Plants with well-developed root systems such as Spartina store food better than shallow rooted and succulent marsh plants like Salicornia and Suada; though emergent growth may be destroyed, plants with rhizomes can send off new shoots. Oil pollution contact during the growing season can produce high seed and seedling mortality and can destroy flowers. Tropical mangrove swamps are also very sensitive to oil. Contamination of leaves, prop roots, and pneumatophores can be lethal to mangroves (Odum and Johannes, 1975; Chan, 1977a; Gundlach and Hayes, 1978).

Because oil can become stranded in marsh wetlands, it is incorporated into the marsh substrate and can inhibit new growth of plants and recolonization by intertidal invertebrates. Spartina marsh can begin regrowth after oil damage very shortly after the incident or during the following growth season (Hershner and Moore, 1977; Bender et al., 1977), while Salicornia and Suada may require several years to begin regrowth (Grundlach, 1980). Mangroves show continued die-off due to contaminated substrate several years after the initial oil spill (Chan, 1977a).

Cleaning up estuaries is a dilemma. Chemical dispersants and emulsifiers are toxic, and dispersed or emulsified oil may be more of a hazard than the oil slick (Nelson-Smith, 1973). Gundlach et al. (1978), and Smith (1970) proposed that some intertidal invertebrates were killed by cleanup efforts used in the Torrey Canyon and Urquiola spills. Physical sinking of oil in estuaries is undesirable because of potential benthic impacts, and combustion could cause property damage or air quality problems in populated areas. Sorbent material uptake of oil is the least damaging method (Little, 1970). Emulsifying agents are equally toxic to marsh plants (Baker, 1971). Cutting and burning have been used with equal success. Marsh recovery from cutting and burning has been about the same as in untreated areas because new growth is initiated from rhizomes. Sometimes, excessive trampling of the marsh in the act of cleanup can be more harmful than the untreated oil.

Recovery in estuaries and wetlands has been monitored after a number of oil spills. Depending upon the extent of damage, many plants and animals can begin recolonization immediately. In some cases, biomass has recovered within 6 months to 2 years; however, changes in species composition and diversity have resulted, reducing ecological stability of the estuary and wetlands (Nelson-Smith, 1973). In some instances, total wetland productivity actually increased following recovery even though the community structure of the marsh was altered and the individual marsh species (Spartina) was a dwarf form (Hershner and Moore, 1977). In the Amoco Cadiz spill, marsh recovery took from 1 to 4 years (Gundlach et al., 1981), while recovery time of wetlands in the Metula spill may be measured in decades (Gundlach, 1980). Though recovery



times are variable, wetlands are considered to have relatively long recovery times compared with other coastal habitats (Adams et al., 1984; Gundlach and Hayes, 1978).

The time it takes for estuarine recovery following an oil spill varies and also may result in changes in species composition and abundance. Recovery times have been estimated at 8 to 10 years for Alaska (Ruby, 1977), to a few years for areas in temperate climates (Adams et al., 1984; Hershner and Moore, 1977; Chan, 1977b). Contamination of benthic substrate is a major factor in influencing recovery (Blumer et al., 1971; Hayes et al., 1980). In areas where natural diversity is low due to environmental stress, a pollution event can have dramatic impacts on estuarine ecosystems and ecotones.

Because of the habitats they contain and their relatively high productivity, estuaries and wetlands are important parts of the marine environment. On any scale of relative environmental sensitivity to oil pollution, estuaries and wetlands rank very high in comparison to other coastal ecosystems (Adams et al., 1984; Michel, Hayes, and Brown, 1978).

Beaches

Beaches and rocky shores are the most extensive shoreline habitats in most of the Outer Continental Shelf planning areas. Exceptions are the Central Gulf of Mexico, Gulf of Alaska, Kodiak, Cook Inlet, Shumagin, St. Matthew-Hall Basin, and Norton Basin planning areas where wetlands, including marshes, bays, and estuaries, are the dominant shoreline habitats. The extent of damage from oil spills on coastal habitats depends largely upon the residence time of oil in or on the habitat. The abundance, diversity, and sensitivity of the biota to oil, and the amount of weathering and physical characteristics of the oil are also important factors in determining the extent and severity of habitat damage. The sensitivity of intertidal fauna to oil is relatively well understood especially for macroinvertebrates of commercial interest. However, little is known about oil effects on macroalgae which may be abundant in rocky intertidal areas (National Research Council, 1985).

In all of the shoreline oil spill sensitivity indices, exposed sandy beaches and rocky shores are ranked relatively low in sensitivity. Oil retention on sandy beaches and rocky shores is short in comparison with retention on sheltered lagoons, tidal flats, marshes, wetlands, bays, and estuaries. Studies of No. 2 oil spilled at West Falmouth, Massachusetts, indicated that the effects of the oil were detectable in the sheltered salt marsh for at least 7 years (Krebs and Burns, 1977). However, oil was more rapidly removed from exposed beaches and rocky shores by waves, winds, and currents. Kolpack (1971) reported that exposed rocks that had been coated with crude oil following the January 1969 Santa Barbara Channel oil spill were free of oil within 3 weeks. A large amount of Santa Barbara crude oil and the straw that had been spread for cleanup purposes remained in the upper intertidal zone of East Cabrillo Beach 18 months after the spill. Only very small patches of the oil-straw residue were found nearly 2 years after the spill in the most sheltered sections of the East Cabrillo Beach study area (Nicholson and Cimberg, 1971). Damage to biota was generally through coating or smothering. There are distinct levels of sensitivity within this shoreline type. In general, exposed, rocky cliffs are the least sensitive to oil spills. Damage is usually minimal because waves, winds, and currents remove oil rapidly, and is usually low (Hayes et al., 1980). Cleanup of exposed rocky shores is usually not required because of the rapid removal by natural forces. Flat, fine-grained, sand beaches that are exposed to significant wave energy are also very low in sensitivity to spilled oil. Fine-grained sand inhibits oil penetration, and oil burial depth is minimal. In cases of extensive contamination, cleanup is accomplished generally through the use of heavy equipment, such as earthmovers. Manual recovery techniques, such as spreading of chopped straw and shoveling, may be employed if the beach is inaccessible to heavy equipment or if the cleanup operations are in a final stage. Damage due to these cleanup techniques is not as great on fine-grained sandy beached as on medium- to coarse-grained beaches. The hard packing of fine-sand beaches simplifies cleanup. Oil burial and penetration are much greater on medium- to coarse-grained beaches. As a consequence of the loosely packed sediments, cleanup operations tend to force oil into the beach (Hayes et al., 1980). Mixed sand and gravel beaches may experience rapid oil penetration to 30 cm. (Hayes et al., 1980). As a result, retention time of oil in these beaches is relatively high, and cleanup is difficult without causing beach erosion. Within the beach/rocky shore habitat type, gravel beaches have a relatively long oil retention time and high sensitivity to spilled oil. Gravel beaches allow rapid oil penetration to 60 cm depth (Hayes et al., 1980). Study of a gravel beach at the Amoco Cadiz oil spill site demonstrated that oil persisted as a fresh mousse 8 months after the spill (Hayes, Gundlach, and D'Orouville, 1979). The long oil retention time results in contamination of the neighboring shoreline environments and the water column. Cleanup on gravel beaches may be accomplished by flushing with high or low pressure water streams (Woodward-Clyde Consultants, 1982). This activity causes high mortality of resident organisms. However, biomass is usually very low in such environments (Hayes et al., 1980).

Sheltered rocky shores are highly sensitive to oil contamination. Spilled oil coats the rough surfaces, and because wave energy is low, the oil may persist from months to years (Hayes et al., 1980). The resident biota may be diverse and abundant, and destruction or significant damage is likely to be caused by the oil and any cleanup. On rocky shores, recovery of intertidal communities to a pre-oil spill condition will depend upon the vertical level of the intertidal zone impacted (Murray and Littler, 1979). The upper barnacle zone normally requires the least time to recover (about 1 year) while the more structurally complex middle and lower levels require longer recovery times.

In general, recovery of rocky intertidal communities should begin within 1 year, and reproductive maturity should be attained within 5 years (Minerals Management Service, 1984).

In summary, sandy beaches and rocky shores are lower in sensitivity to spilled oil than marshes, wetlands, tidal flats, bays, estuaries, and lagoons. Oil retention time, as well as abundance, diversity, and biomass of biota, is generally low on sandy beaches and exposed rocky shores. Within the beaches/rocky shores habitat type, degrees of sensitivity to oil spills exist, with protected rocky shores exhibiting the highest level of sensitivity.



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*Study sponsored by the OCS Environmental Studies Program.



## Sensitivity of Marine Habitats to Oil Spills

The sensitivity of marine habitats (other than mud/sand bottoms) to spilled oil is discussed in the following sections. The major portion of each planning area consists of mud/sand bottoms which have a low sensitivity to spilled oil. The specific marine habitats discussed are submerged aquatic vegetation, submarine canyons, the shelf break zone, coral reefs, and live hard bottoms. The information summarized in the following discussions was used in calculating the relative environmental sensitivity of the OCS planning areas to spilled oil. Most of these marine habitats are generally too deep to receive large quantities of oil from the ocean's surface. The principal areas of sensitivity are shallow habitats such as beds of aquatic vegetation and coral reefs. The highly sensitive coral reefs, which occur only in the South Atlantic and Gulf of Mexico planning areas, do not occupy sufficient area to affect the sensitivity ratings significantly. Live hard bottom habitats may be sensitive in shallow areas, but information on the areal and depth distribution of these habitats is not available for most OCS planning areas. As a result of the low sensitivity of most marine habitats in the OCS planning areas, the sensitivity ratings for these habitats are lower than those for coastal habitats and marine biota.

### Submerged Aquatic Vegetation

There are rooted seagrass beds as well as accumulations of macroalgae and microalgae forms in most of the subtidal, coastal portions of OCS planning areas. The seaward extent of their distribution is limited by the penetration of sufficient sunlight to support photosynthesis. Their abundance and distribution ranges from the estimated 3.7 million acres of seagrass beds in the Gulf of Mexico, 90 percent of which are off the coast of Florida, to the epontic algae forms which are found growing under ice in Alaska. There are also sparse assemblages of macrophytic algae distributed in the Arctic waters of Alaska (Minerals Management Service, 1983; Minerals Management Service, 1984a). These plants all play an important role in the productivity of the oceans. Their organic productivity is generally high and may actually exceed the production of intensively farmed agricultural crops. For example, productivity estimates for California kelp range from 3,000 to 22,000 grams/square meter. Their decomposition into detritus provides an important source of organic matter for the food web in the area. They also provide a substrate and habitat for many invertebrate and vertebrate animals, which in turn are eaten by other predators. Seagrass beds provide breeding, nursery, and feeding areas for a wide variety of commercially important shellfish and finfish (Minerals Management Service, 1983). Ice algae forms account for 25 to 30 percent of the primary production in areas of the Beaufort Sea (Minerals Management Service, 1984b). The effects of oil spills on true marine, subtidal forms are relatively unstudied. An assessment of effects on seagrass beds has been largely extrapolated from studies of intertidal and emergent plant forms found in coastal marshes and wetlands. The most severe impacts would occur in shallow (up to several meters) coastal areas where oil could come in close contact with the vegetation in an undiluted form. While most seagrasses and algae are resistant to oil contamination, repeated applications will destroy the root and rhizome systems and denude the area (Thomas, 1979).

In heavy applications of oil, algae may become bleached and lose fronds. Oil and tar may adhere to shallow forms and tear the algae away from its point of attachment through wave action. Ironically, very light oiling may actually enhance growth in certain forms (Thomas, 1979). Damage to plants would also be greater during the active growing periods in the spring and summer (Minerals Management Service, 1984a). The effects on shallow vegetation, therefore, can be extensive and may require 1 to 3 years to recover from an oil spill incident (O'Neil et al., 1983).

Deep water forms of aquatic vegetation would probably not be as severely affected. The probability of oil being incorporated into the water column and transported to extensively vegetated areas is unlikely. In addition, the oil would be diluted and widely dispersed. Contact with oil, therefore, would be transient in nature. (Minerals Management Service, 1983). The use of dispersants in oil spill cleanup operations should further dilute oil, and should result in reduced toxicity to aquatic vegetation, assuming low toxicity dispersants are employed. Mechanical removal techniques should only impact shallow communities and should not exceed damage caused by direct oiling (Thomas, 1979).

Submarine Canyons

Submarine canyons are natural features of the world's continental shelves and slopes. Most were formed by river and stream erosion in the geologic past when the shelf was a terrestrial feature, although some have been formed by faulting and erosional bottom currents (Heezen, 1978). On the U.S. continental margin, the largest concentration of canyons is found in the Mid- and North Atlantic, where more than 70 named and hundreds of unnamed canyons are located (Hecker et al., 1983). The Gulf of Mexico contains three major canyon systems, California has isolated canyons throughout the shelf, and the Alaskan shelf has numerous canyons primarily in the Gulf of Alaska and the Bering Sea.

Most canyons occur at the shelf edge, incising both the shelf and continental slope. Topography and physical forces interact in many canyons to create and maintain a habitat that can be quite different from the surrounding lower-relief bottom. Bottom-dwelling organisms in canyons are distributed patchily but represent a more diverse assemblage than those found on the surrounding slope and rise in the North and Mid-Atlantic (Hecker et al., 1983). The Atlantic canyons are important habitats for lobster, red crab, squid, marlin, tilefish, and swordfish. Other species, such as deep-water corals, that require a hard substrate for attachment, occur in greater abundance and diversity in canyons where more hard substrate is found than on the adjoining slope (Hecker, 1983).

Canyons are natural conduits between the continental shelf and the continental rise for water, suspended material, and nutrients. Tidal currents and other water mass movements move materials both up and down the axes of canyons, resuspend sediment from the floors of canyons, and occasionally retain materials for significant, but as yet undefined, periods of time (Butman et al., 1982). Canyon heads are probable entry points for natural and pollutant materials from the continental shelf (Hecker et al., 1983).



Materials such as oil or drilling fluids discharged in or near canyon heads could move into the canyons and be retained there for some period of time that might prove deleterious to indigenous biological resources. This phenomenon has not been observed for discharged drill fluids, which are the only pollutants studied systematically. However, some oil could enter canyons through adsorption onto particulate matter such as drill mud clay particles. During the Georges Bank Monitoring Program, a sediment trap located in Lydonia Canyon was examined for barium content from drilling discharges from Sale 42 (North Atlantic) leases. Evidence of accumulation of these materials was not found in Lydonia Canyon, located approximately 10 miles SSE of one drilling operation (Block 312) and 25 miles east of another (Block 410) (Bothner, 1983). However, Bothner (1983) also demonstrated increases in sedimentary barium concentrations as far as 40 miles to the west of these same operations. Local hydrographic conditions determine deposition, and conditions in canyons may not be conducive to entrapment and accumulation.

Direct effects of spilled oil on deep submerged features such as canyons have not been studied systematically in the field. However, significant adverse direct effects are not anticipated. Freshly spilled oil rises to or floats at the ocean's surface where forces of dispersion and dissipation begin acting immediately. Oil spreads and evaporation to the atmosphere rapidly removes the more volatile, toxic components. Dissolution into surface waters and continued dispersion by winds, waves, and currents operate to reduce the spill further. The National Academy of Sciences (1975) estimated that 75 to 80 percent of an oil spill is removed by these various weathering processes before the final products of a spill are formed. The visible final products are generally referred to as "tar balls," bits of tar that remain at or near the surface and are transported by winds and currents. The density of most weathered oil does not become great enough for neutral buoyancy to occur (NRC, 1985), which means, in most cases, that tar balls do not sink. The NRC (1985) notes four important sedimentation mechanisms by which petroleum can reach sediments: 1) sorption of oil by suspended particles such as clay and detritus; 2) ingestion of oil by zooplankton and incorporation into fecal pellets; 3) weathering of oil by physical/chemical processes; and 4) direct mixing of oil and sediments. The first two mechanisms are probably the most important as far as potential impact to submarine canyons, but cumulatively they would only account for a small portion of the spill reaching bottom in deeper water. Given upon ocean conditions, the average depth of canyons, physical dispersion of these materials, and chemical and biological transformations, there is a low likelihood of impact to canyons and canyon fauna.

As little is known of the possible effects of an oil spill on canyons, the potential for habitat recovery from such an event is also little known. It is known that canyons are dynamic environments that would presumably aid recovery. Recovery could not be aided by cleanup intervention, as technology for deep water cleanup has not been developed and would be prohibitively destructive and expensive.

## The Shelf Break Zone

The continental margin (submerged land from the coastline to the deep ocean) consists of two primary features, the continental shelf and the continental slope. These physiographic features are generally delineated by steepness; the shelf is the area of nearly flat terrain that extends from shore to the shelf/slope break where steepness markedly increases. The steeper bottom that extends down to the continental rise and abyssal depths is the continental slope. The break is generally considered to occur at 200 meters, although by the steepness criterion, the break can occur anywhere from 20 to 400 meters. In relation to the shoreline, the shelf/slope break may be found immediately offshore, or be located hundreds of miles from shore. On the U.S. continental shelf, the Atlantic Region has an average shelf width of 40 miles, the Gulf of Mexico has an average width of 60 miles, the Pacific Region has a narrower shelf, and Alaska varies from a 100 mile shelf in the Gulf of Alaska to broad shelves of several hundred miles in the Bering and Beaufort regions (Alaska Department of Community and Regional Affairs, 1976). The break was created and maintained over geologic time by a combination of lower sea level during Pleistocene times, uplift, subsidence, faulting, slumping, and erosional currents (Heezen, 1978).

The shelf break zone is a transition zone of biologic and non-biologic parameters from shallower shelf conditions and communities to deep water conditions. Non-biologic parameters such as light, temperature, and pressure change dramatically as depth increases rapidly beyond the break. Bottom sediments and organisms become less and less affected by such surface phenomena as atmospheric temperature, winds, and storms, phenomena that are extremely important in determining the fate of an oil spill. Biological communities also represent a transition zone to deeper communities that are adapted to less or no light, greater pressure, and lower energy current regimes.

The shelf break zone is also the area where many of the topographic and physiographic features discussed elsewhere are found. The numerous Atlantic canyons, as well as many canyons elsewhere, typically cut through the shelf break zone. Many of the topographic rises (fishing banks, Flower Gardens reefs) in the Gulf of Mexico are located near the edge of the continental shelf. Deep troughs and valleys parallel the break in many areas; seamounts are located in deep waters in the Gulf of Alaska relatively close to the shelf/slope break.

The shelf break zone, as a transition zone between shallow and deep water environments, is a virtually continuous and extensive feature of the world's oceans. Biologic composition of transition zone communities, as with shallow and deep water communities, varies with latitude, but this variation is also gradual without abrupt discontinuance based solely on latitude.

Direct effects of spilled oil on deeper submerged features such as the shelf break zone have not been well studied in the field. The typical behavior of spilled oil, however, would mitigate against serious effects.



Spilled oil from whatever source is assumed to rise to or stay on or near the ocean surface, where forces of dispersion and dissipation begin acting immediately. Oil spreads and evaporation to the atmosphere rapidly removes the more toxic volatile components. Dissolution into surface waters and continued dispersion by winds, waves and currents operate to reduce the spill further. It has been estimated (National Academy of Sciences, 1975) that as much as 75 to 80 percent of a given spill is removed by the various weathering processes before the final products of a spill are formed. The visible final products are generally referred to as "tar balls," bits of tar that remain at or near the surface and are transported by wind and water movements. The density of most weathered oil does not become great enough for neutral buoyancy to occur (NRC, 1985), which means, in most cases, that tar balls do not sink. The NRC (1985) notes four important sedimentation mechanisms by which petroleum can reach sediments: 1) sorption of oil by suspended particles such as clay and detritus; 2) ingestion of oil by zooplankton and incorporation into fecal pellets; 3) weathering of oil by physical/chemical processes; and 4) direct mixing of oil and sediments. The first two mechanisms are probably the most important as far as potential impact to the shelf break zone, but cumulatively they would only account for a small portion of the spill reaching bottom in deeper water. Given open ocean conditions, the average depth of the shelf break zone, physical dispersion of these materials, and chemical and biological transformations, there is a low likelihood of impact to the shelf break zone and its associated fauna.

Just as little is known of possible direct and indirect effects of an oil spill on the shelf break zone, the potential for habitat recovery is also little known. The habitat and fauna are less affected by surface phenomena and thus less energy is imparted to them, but it can be a dynamic environment nevertheless. Recovery potential would be basically the same in most areas, with areas of colder bottom water and less current energy being somewhat slower to recover. Recovery could not be aided by cleanup intervention, except insofar as surface cleanup reduces the amount of material that could reach bottom. Surface cleanup would not damage shelf break habitats or biotic resources.

## Coral Reefs

The only true flourishing tropical coral reefs on the U.S. continental shelf are found in the Dry Tortugas, along the Atlantic side of the Florida Keys northward to near Miami, and at the East and West Flower Gardens in the northwestern Gulf of Mexico. Coral reefs are dominated by hermatypic (reef-building) corals and coralline algae that are restricted in their distribution by light and temperature. There are many other types of corals (stony, alcyonarians) that do not build reefs that are found throughout the world's oceans. Concentrations of hermatypic and non-hermatypic corals are found in many locations in the Gulf of Mexico and South Atlantic, but true tropical coral reefs are only found at the locations noted above. The Florida Keys and Tortugas reefs are shallow reef communities (3 to 6 meters) dominated by branching coral species, while the Flower Garden reefs are deep-water structures (15 to 52 meters) dominated by coral head species and where no branching species are found (Bright et al., 1983).

Corals of various types are known to be affected by oil, both crude and refined, and by dispersants sometimes used in cleanup operations (Connell and Miller, 1980). Different species have different latency periods during which there appears to be no response to the initial contact with oil. This latency is attributed to the ability of live coral to secrete a protective mucus when stressed (Reimer, 1975). After the latency period, the variability of type and duration of response is quite wide. Responses to contact with oil or oil in water mixtures include polyp retraction or extension, tissue rupture, zooxanthellae (symbiotic algae) expulsion, reduced feeding activity and growth, loss of color and mortality. The NRC (1985) summarized some of the more recent work on responses of coral to oil, in addition to the types of responses noted above. Oiled reefs exhibited smaller numbers of breeding colonies, a decrease in the average number of ovaria per polyp, smaller numbers of planula larvae produced per coral head, and a lower settlement rate of planulae on artificial substrates. Extrapolation of results to field conditions, and comparison of field studies is severely hampered, according to the NRC report, by a lack of reliable information on the actual concentrations or composition of oil in the water near the reefs, as well as a poor understanding of reproductive physiology and metabolism of reef corals.

Many of these responses above are elicited by exposure to an oil in water mixture with a concentration in the 100 ppm to 500 ppm range (Lewis, 1971). Field studies in the Persian Gulf (Shinn, 1972; Spooner, 1970) have indicated, however, that reefal systems seem to have suffered little in areas of chronic oil pollution from natural seeps and transportation. The Flower Gardens themselves have been the subjects of a multi-year characterization and monitoring study conducted by the Texas A & M Research Foundation. To date, no deleterious effects of intensive nearby exploration and development have been observed on the coral reef cap or surrounding coralline algae apron (Texas A & M Research Foundation, 1983). The methodology used by Texas A & M and the statistical ability to detect anything other than massive coral mortality has recently been questioned (Clement Associates, 1984), although this study focused on potential effects of drilling muds. Deeper reefs like the Flower Gardens are more likely to be insulated from spilled oil than shallow reefs such as the Keys; a depth related effect to surface oil (decreased response with increased depth) has been observed by Cohen, Nissenbaum, and Fisler (1977).

Recovery potential of corals exposed to oil appears to be quite high, at least in laboratory and field tests of short term recovery after an exposure. Several investigators (Elgershuizen and De Kruijf, 1976; Grant, 1970; Coles and Maragos, 1972; Shinn, 1972) have noted that various coral species apparently recover completely from short term oil exposure once the exposure ceases and the corals are reintroduced to uncontaminated seawater. These authors also note that these were modestly gross appraisals, that sublethal effects may have occurred that were not observed, and that longer-term exposures to low-level concentrations of petroleum may have different results. Little work has been done on these aspects of the problem.

Some work has been done on one aspect of cleanup as it relates to coral. In cases of coral recovery noted above, the recovery was natural in that it occurred with re-exposure of the corals to uncontaminated seawater.



Elgershuizen and De Kruijf (1976) ran toxicity tests of petroleum and certain oil dispersants on a stony coral species. Mixtures of dispersants and oil increased the toxicity of both considerably. These authors concluded that oil is dangerous for reef ecology, but chemical cleanup procedures may expose reefs to greater dangers.

Live Hard Bottoms

"Live" bottom areas are defined as areas containing "biological assemblages consisting of such sessile invertebrates as sea fans, sea whips, hydroids, anemones, ascidians, sponges, bryozoans, or corals living upon and attached to naturally occurring hard or rocky formations with rough, broken, or smooth topography, or whose lithotope favors the accumulation of turtles, fishes, and other fauna" (South Carolina Marine Resources Research Institute, 1981). The terms "live bottom" and "hard bottom" have been used somewhat interchangeably, but for clarification, a live bottom habitat must have hard bottom substrates to provide for attachment of organisms and development of a live bottom community, whereas hard bottom areas are not necessarily live bottoms. Live bottom communities found in the Gulf of Mexico and the South Atlantic are typically composed of species commonly found in tropical coral reefs, and as such are limited in their northern extent on the U.S. continental shelf to sub-tropical and temperate zones. Live bottoms are distinguished from coral reefs by the absence or near absence of hermatypic (reef-building) coral species, although other types of coral may be present. Significant live bottom habitats on the U.S. shelf are found in the South Atlantic off the coasts of North and South Carolina, Georgia and northern Florida, in the Gulf of Mexico on the numerous hard banks in the central and western regions and at the Florida Middle Grounds off northern Florida, and on hard banks and rises off the coast of Southern California. There is abundant geophysical evidence that extensive hard bottom habitats also exist offshore Central and Northern California. There is a high probability that these habitats contain live bottoms.

Biotic diversity in live bottom communities is clearly higher than surrounding soft-bottom clay or sand habitats, but almost never as high as tropical coral reef communities (Bright, 1983). South Carolina Marine Resources Research Institute (1981) and Texas A & M Research Foundation (1983) both recognize live bottom habitats in three bathymetric zones: nearshore or inner shelf, mid-shelf, and outer shelf which includes the shelf-slope break. Depths used to characterize these zones are different in the Gulf than in the Atlantic, with inner shelf live bottoms occurring shallower in the Gulf than in the South Atlantic. South Atlantic studies utilize 19-27m in depth for inner shelf, 28-55m for middle shelf, and 56-100m for outer shelf. Depth of habitat is an important consideration in assessing the vulnerability of a habitat to oil spills, due to the inherent behavior of spilled oil to rise to, or remain near, the sea surface.

Little experimental work has been done on the effects of oil spills on high diversity live bottom communities, either in controlled field or laboratory conditions or during accidental oil spills. Due to the similarities of these communities to coral reef communities, some limited information on effects and recovery of reefs may be extrapolated to live bottom communities. Coral responds to oil or oil in water mixtures by mucus secretion, polyp retraction or extension, tissue rupture, zooxanthellae expulsion, reduced feeding activity and growth, and loss of color and mortality, depending on length and severity of exposure. Many of these responses are elicited by exposure to an oil in water mixture with a concentration in the 100 ppm to 500 ppm range (Lewis, 1971). Field studies in the Persian Gulf, however, have indicated that reefal systems seem to have suffered little in areas of chronic oil pollution from natural seeps and transportation (Spooner, 1970; Shinn, 1972). The Flower Garden reefs in the Gulf of Mexico have experienced no deleterious effects from intensive nearby oil and gas exploration and development (Texas A & M Research Foundation, 1983). Deeper reefs, and presumably live bottoms, are more likely to be insulated from spilled oil; a depth-related effect to surface oil (decreased response with increased depth) has been observed by Cohen, et al. (1977).

Recovery potential of coral appears to be high, at least to short-term exposure to oil followed by reintroduction to uncontaminated seawater (Grant, 1970; Shinn, 1972; Coles and Maragos, 1972; Elgershuizen and De Kruijf, 1976). These investigators noted that sublethal effects and effects from long-term low level exposure were unknown, except for the Persian Gulf observations noted above. Toxicity of spilled oil seems to be increased with the use of certain chemical oil dispersants (Elgershuizen and De Kruijf, 1976); live bottoms would presumably be more susceptible if these dispersants were used in cleanup operations. However, advances are being made in decreasing the toxicity of dispersants.

Live bottom areas would be severely stressed by direct contact with spilled oil. The depths where these habitats are found, however, serve to protect them against long-term direct contact with spilled oil. Sublethal effects and effects from long-term low level oil contamination are not known at present.



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## Sensitivity of Biota to Oil Spills

The sensitivity of various groups of biota to spilled oil is discussed in the following sections. The information provided in these discussions was used in calculating the relative environmental sensitivity of the OCS planning areas to spilled oil. A similar evaluation was performed for the 1982 analysis of environmental sensitivity. However, the information from that evaluation was not joined with the results of the habitat analyses. In this way, the 1982 analysis avoided redundancy. The present analysis incorporates the redundancy between habitats and biota. This incorporation provides a more complete understanding of the sensitivity of each planning area than that provided by the 1982 analysis. The overall sensitivity of each OCS planning area is a combination of the sensitivities of the habitats and biota which occur within its boundaries.

### Plankton

Phytoplankton (microscopic plants) and zooplankton (microscopic animals) lack means of avoidance and are vulnerable to floating oil as well as the dissolved and entrained oil beneath the ocean surface. Individual plankton may be affected by toxic reactions to components of the oil or by physical coating which impairs the exchange of gases (Hyland and Schneider, 1976). Additionally, zooplankton ingest oil. Some copepods and barnacle larvae do not distinguish between food particles and oil droplets and ingest either as the opportunity arises (Parker, Freegarde, and Hatchard, 1971). As much as 10 percent of the oil (bunker C) released from the wreck of the Arrow was associated with feces of the zooplankton. Seven percent of the weight of the feces was bunker C fuel oil. Conover (1971) estimated that in addition to normal sedimenting processes, 20 percent of the particulate oil was deposited as zooplankton feces.

The severity of effects of petroleum hydrocarbons on plankton is dependent on such factors as the species composition, season, temperature, light intensity, and on the concentration as well as the type of petroleum (Sanborn, 1977). Toxins from spilled oil reduce populations of all types of plankton (Royal Commission on Environmental Pollution, 1981). In general, unicellular algae are killed when toxic oil components are present in the water column in excess of 1 part per million (ppm) and cell division is retarded by exposure to concentrations exceeding 0.1 ppm. Sanborn (1977) reported the two periods when contamination by oil would be most critical for zooplankton are at the extrusion of gametes and at the time of metamorphosis and setting on benthic substrates.

Mironov (1969), Kunhold (1970), and Corner, Southward, and Southward (1968) reported that zooplankton larvae are 10 to 100 times more sensitive to oil than adults. While individual species' toxicities for eggs and larvae vary, a generally accepted toxicity threshold is 50 ppb (Kunhold, 1977; Kunhold et. al., 1978; Sanborn, 1977). Not only are eggs and larvae usually more sensitive to petroleum, but in many cases their period of exposure is lengthened because they float passively along with the spilled oil. This significantly increases the potential of extensive mortality. This effect is



mediated for many species, whose larval development results in vertical movement throughout the water column and descent to the bottom.

There is evidence that oil spills in open water have little more than a transient effect on plankton. Observations of the impact of the Torrey Canyon wreck are illustrative of available information. Although this spill occurred at a time when the zooplankton contained a large number of pilchard eggs and high mortality was observed, there was no detectable effect in the pilchard population in subsequent years (Royal Commission on Environmental Pollution, 1981). With exceptions, the recovery of phytoplankton and zooplankton communities, particularly in large bodies of water, is apparently rapid. These species are widely dispersed, reproduce rapidly, and grow quickly to maturity; and pre-spill population densities and/or stable age-distributions are soon restored (Hyland and Schneider, 1976). However, when a spill occurs in or impinges upon estuarine nursery grounds or other confined communities, such as those under ice, small localized breeding populations, especially the larval forms of some fish, or crustaceans and molluscs, may be severely affected, and complete recovery may take several years (Council on Environmental Quality, 1974; National Research Council, 1985).

### Mud/Sand Benthos

Most studies at oil spill sites have examined the effects of petroleum on the intertidal communities. These communities have been the focus of study for several reasons. First, most spilled oil floats and contacts the intertidal zone. Oil deposited in the intertidal zone is visible from shore, and the intertidal environment is more easily accessible for study than subtidal habitats. Finally, the intertidal zone historically has been a primary area of study and, consequently, provides a much better baseline for determining effects of oil spills (Sanborn, 1977). For these reasons, effects of oil spills on the subtidal soft-bottom benthos have not been studied as thoroughly as those on intertidal communities.

Several mechanisms facilitate the transport of oil from the ocean's surface to bottom sediments. Weathering of oil results in increased density and sinking, adsorption of oil to suspended particulate matter results in sedimentation, and ingestion of oil by zooplankton with subsequent incorporation in fecal pellets also results in sedimentation of oil. Conover (1971) reported the presence of oil droplets in zooplankton feces in Chedabucto Bay following the Arrow spill in 1971. Significant levels of petroleum residues were also found in zooplankton fecal pellets in the Sargasso Sea (Sleeter and Butler, 1982). Hydrocarbons that are encapsulated in zooplankton feces are sedimented, but the ultimate fate of these hydrocarbons is unknown (Sleeter and Butler, 1982).

Impacts from oil spills on subtidal soft-bottom benthos generally are considered to be low (MMS, 1983a). This is especially true at increasing water depths where probability of impact is lower and weathering and dilution of the oil is greater (MMS, 1983a). The benthic fauna in the Santa Barbara Channel was studied following the oil spill from Platform A in 1969. No effects directly attributable to the oil spill were observed in the subtidal benthic fauna. Fauchald (1971) emphasized that this conclusion did not imply that the oil spill had no effects. It was not possible to separate effects that the oil may have had on the soft-bottom benthos from other natural and anthropogenic factors.

A study of the IXTOC oil spill, funded by the Department of the Interior, compared community parameters at 12 stations in the Gulf of Mexico off the coast of Texas. The study compared soft-bottom community composition from samples collected 2 to 5 years before the oil spill to samples taken after oil from the IXTOC spill had been observed in the area. A principal conclusion of this study was that the temporal variations observed in the soft-bottom benthic communities could not be related definitely to the oil spill (ERCO, 1982).

A large spill of No. 5 fuel oil occurred when the tanker Tsesis grounded in the Baltic Sea off the coast of Sweden. Biological samples of the soft-bottom benthos from a depth of 30 m were collected following the spill. A significant reduction in total macrofauna abundance at one station was attributed to effects of the oil (Elmgren et al., 1980). The reduction in macrofauna was due primarily to the nearly total disappearance of two normally abundant species of amphipods and one species of polychaete. The investigators suggested that this reduction was due to emigration of these motile species. More sedentary organisms, such as clams, remained at normal abundances with no increase in mortality. Abundance of all meiofauna groups, except nematodes, was reduced, and high mortality of ostracods was reported.

In a study of the March 1978 Amoco Cadiz oil spill, Gundlach et al. (1983), determined that approximately 8 percent of the total oil lost was deposited in subtidal sediments. Much greater amounts of the spilled oil washed into the intertidal zone (28 percent) or evaporated (30 percent). Despite the low percentage of oil deposited on the subtidal benthos, numerous razor clams and heart urchins in shallow subtidal areas were killed during the first few weeks after the spill (Cross et. al., 1978). The residence time of oil in subtidal sediments varied with sediment type and physical energy of the area. Oil concentrations in areas with coarse-grained sediments and swift currents decreased by nearly 75 percent after 6 months, 90 percent after 18 months, and nearly 100 percent 30 months after the Amoco Cadiz spill. In areas with little physical energy and fine-grained sediments, oil persisted at high concentrations more than 3 years after the oil spill.

In summary, the soft-bottom benthos exhibits relatively low sensitivity to spilled oil in comparison to hard-bottom and intertidal communities. In many studies of oil effects on subtidal soft-bottom benthic communities, natural variability within the community is responsible for most observed changes in abundance and diversity of benthic populations, and effects cannot definitely be attributed to the oil spill as a primary cause.

## Fish and Shellfish

The severity of the impact of spilled oil on fish and shellfish is a function of the size of the oil spill, the composition of the oil to which the fish are exposed, the duration of the exposure, and the life stage and season during



which the fish and shellfish are exposed. The physico-chemical characteristics of the oil and the duration of exposure are influenced by local hydrodynamic and meteorologic characteristics.

Fish might be more sensitive to short-term, acute exposures, in comparison to invertebrates according to the National Research Council (NRC, 1985). Rice et. al. (1979), observed that pelagic species of fish seem to be more tolerant than benthic species while fish inhabiting intertidal areas appear to be the most tolerant. Benthic species are of special concern because of their association with benthic sediments which would be the ultimate sink for spilled oil.

The effect of petroleum on the ecology of fishes, however, and most other marine life, is not completely understood. The following generalities are results based on the extensive research carried out at the organismic level.

1. Sensitivity of fish to oil generally diminishes from eggs to larvae to fry to adults. Eggs and larvae may die in spawning or nursery areas due to coating or direct toxic effects. Crude and bunker oils are toxic to fish eggs at concentrations of 1 ppm. Major behavioral abnormalities have been reported in larvae at concentrations of 0.0001 ppm.

2. Adults may be killed from direct toxic effects or indirectly as a result of maladaptive behavior. Behavioral changes may include loss of equilibrium, inability to school, and reduced swimming activity.

3. The reproductive output of adults may be affected.

Additional sublethal effects reported in studies of the effects of oil on fish include: histological damage, and physiological and metabolic perturbations. Because repair or recovery requires energy, these sublethal effects can lead to vulnerability to disease or to decreased growth and/or reproductive success. (National Research Council, 1985).

Mironov (1969), Kunhold (1977), Kunhold et. al. (1978), and Corner et al. (1976), reported fish larvae to be 10 to 100 times more sensitive to oil than adults. Individual species' toxicities for eggs and larvae vary, but the generally accepted toxicity threshold is 50 ppb (Kunhold, 1977; Kunhold et. al., 1978; Malins, 1977). Not only are eggs and larvae usually more sensitive to petroleum, but in many cases their period of exposure is lengthened because they float passively along with the spilled oil, resulting in the potential extensive mortality. This effect can be mediated for many species, whose larval development results in vertical movement through the water column and descent to the bottom.

Ebeling et. al. (1971), reported that fish may be less vulnerable to spills than any other groups of aquatic organisms because of their mobility and avoidance reactions. Nelson-Smith (1973) suggested that because large fish kills have not been reported following oil spills, one must presume that actively swimming fish avoid spills. However, groundfish are likely to experience extended exposures from oil which has been deposited in benthic sediments.

Numerous mortalities of benthic invertebrates have been reported (Hampson and Sanders, 1969; Sanders, 1981) when spilled oil contacts bottom communities. The predominant cause of death is smothering, but if the spill is fresh (less than 3 days old) the more toxic components may still be present and may contribute to mortality. Behavioral modifications and reduced reproductive capacity may also result from such exposures. Using a flow-through bioassay system with 0.25 ppm crude oil, Capuzzo (1982) observed that postlarval lobsters were less sensitive to crude oil-sea water mixtures than the larval stages. Disruptions in the energetics of larval development were observed, but the normal pattern of energy storage and utilization was slowly restored when the organisms were transferred to uncontaminated water. In a flow-through bioassay system using 50 ppb and 500 ppb Lago Medio crude oil, the bivalve Mya truncata did not display any behavioral stress response relative to that of the control (Mageau and Engelhardt, 1984).

The magnitude of impact from a spill is highly variable. Assessment of impact on a biological resource is most often based upon long-term effects to the population as a result of initial egg and larval mortalities. Species which rely heavily on one or a few successful year classes to supply the majority of the recruitment are particularly vulnerable to environmental perturbations, both natural and man induced, such as oil spills. If numerous sexually mature animals die from direct coating or toxicity, the size and reproductive potential of the population could be significantly reduced. Based on reported avoidance reactions, mortality to adult finfish is not expected to be significant.

Individual species may be more or less sensitive to spilled oil. Larval development rates and pathways vary; for example, herring have demersal eggs and planktonic larvae, whereas cod have planktonic eggs and demersal larvae, so that exposure to an oil spill will have different impacts on differing species at the time of an oil spill.

Where fishery resources are widespread, impacts from a spill are likely to affect only a small portion of the population. There exists no direct evidence that an oil spill has affected a stock as a result of mortality of eggs and larvae (Boesch et al., 1984). A large spill occurring during a critical recruitment period could seriously diminish recruitment to the stock for the year, particularly for those species in which eggs and larvae concentrate in the near-surface waters. For a species such as haddock in which only one year class of every five to ten contributes substantially to the fishery, the loss of a good year class could be disastrous; for other species, such as cod, in which the contributions of the different year classes are much more uniform, the effect on the stock would be much less important. Boesch et al. (1984), concluded that the probability of a significant effect on a stock occurring is low on the basis of the improbable coincidence of a critical recruitment period and a large spill resulting in toxic effects.

Because juvenile forms of many economically important species live in inshore environments, events there may affect those species even though offshore adult populations are not directly or immediately affected.



Marine Birds

Birds which spend most of their time on the surface of the sea and dive for their food are at greatest risk from oil spills (Royal Commission on Environmental Pollution, 1981). When birds encounter floating oil, their plumage becomes matted. Matting allows water to penetrate the air space between the feathers and the skin, and the birds lose buoyancy and drown. Oil also destroys the insulating layer, and the body loses heat. In colder climates the loss of heat is critical. In heavily oiled birds, the body responds by increasing its metabolism to approximately twice the normal rate. Severely oiled birds are unable to hunt for and catch food; this results in rapid emaciation and small chance for survival. Even light oiling causes an increase in weight and affects the aerodynamic properties of the wings. This impairs the ability of the bird to forage (Holmes and Cronshaw, 1977).

In addition to the problems caused by external coating by oil, sea birds ingest oil through preening and through consuming oil-contaminated food (Holmes and Cronshaw, 1977). This may lead to respiratory and intestinal irritation and damage to the liver and kidneys (Royal Commission on Environmental Pollution, 1981). Holmes and Cronshaw (1977) reported that ducks which had been fed oil-contaminated food suffered a higher mortality rate when exposed to lower temperatures than a control group.

Oil spills may interfere with the reproductive rate of marine birds. This is of concern because they often produce only one egg each season per pair (Royal Commission on Environmental Pollution, 1981). Oiled birds returning to the nests can contaminate the eggs. Coating of the eggs by petroleum reduces their hatchability (Holmes and Cronshaw, 1977). This reduced hatchability may result from impairment of gaseous exchange through the shell (Holmes and Cronshaw, 1977) and/or penetration of the shell by hydrocarbons with adverse effects on the embryo through systemic action (Albers, 1978).

There is no direct relationship between the amount of petroleum released in a spill and the number of birds killed. The known number of birds killed as a result of the 200,000 tons of oil released by the wreck of the Amoco Cadiz (4,572 birds) contrasts sharply with the death of 50,000 birds as a result of the discharge of 1,000 tons of fuel oil off northeast Britain (Holmes and Cronshaw, 1977; National Research Council, 1985).

The largest number of mortalities occur when oil spills encounter large concentrations of birds, especially in enclosed inlets or estuaries. Seabird population models (Wiens et al., 1979) project that recovery periods as long as 20 to 50 years may be required if breeding adults of groups such as alcids and storm petrels, which are characterized by very low reproduction rates, suffer substantial losses from a spill. A major oil spill coinciding with a period of high natural mortality, such as that caused by limited food resources, could substantially increase bird mortality and retard natural recovery of the population (Ford et al., 1982). Despite this potential for major impacts, Clark (1984) has concluded that mortality of seabirds from oil pollution does not, in general, appear to result in a detectable effect on seabird populations. In contrast, northern (Arctic) auk populations are already in serious decline from other forms of human interference, and increased exposure to oil pollution is likely to affect them more seriously. Marine birds will be more affected by spilled oil in cold waters than in temperate waters due to the slower evaporation of the more volatile fractions. Oil frozen into the sea ice and released during thaw may further prolong the effects of a spill (National Research Council, 1985).

Although cleaning and rehabilitation of oiled birds is possible, only a very small proportion of marine birds can be rescued, rehabilitated, and returned to the sea (Royal Commission on Environmental Pollution, 1981). Clark (1984) reports that other methods are being used to reduce impacts of oil spills on marine birds. These include scaring the birds from the path of the spill, protecting sensitive areas with booms, chemical dispersion of the spill, increased regulation of shipping practices, and greater government control of the oil industry.

Coastal Birds

Coastal birds have the same sensitivity to contact with oil as marine birds. However, because of their various nesting, resting, and feeding habitats and behaviors, coastal birds as a group have a lower risk of exposure to oil pollution compared with marine birds (Perkins, 1974).

In addition to their use in flight, a bird's feathers provide insulation and buoyancy. The feathers and down trap air and are hydrophobic allowing the birds to swim and float without wetting or chilling. Feathers are also oleophilic so that oil is readily adsorbed and difficult to remove. Oil destroys the air holding structure of the feathers and down permitting water to reach the bird's skin. As a result, natural buoyancy and insulating properties of the feathers are lost (Hansen, 1981).

Birds succumb to physical contact with oil in a number of ways. Heavily oiled birds weighed down by oil can drown. The literature indicates that 50 to 90 percent of birds oiled in a spill never reach shore but drown and sink (Nelson-Smith, 1973). Hypothermia due to a loss of insulation is another cause of death. As a result, winter mortality rates for oiled birds are higher than those for summer or warm water, partially due to migration concentrations, but mostly due to temperature stress. Metabolism may double in an oiled bird as it tries to maintain body heat, and starvation can add to the bird's stress (Royal Commission on Environmental Pollution, 1981). Oiled birds that reach shore begin preening incessantly. This preening further destroys the structure of the feathers, and birds will not stop preening to eat. This preening behavior and accompanying shock are additional stresses that can lead to starvation (Nelson-Smith, 1973).

Behaviors of coastal birds affect their contact with oil. Some migratory waterfowl have been observed to settle on oil slicks preferentially because the surface is smooth (Nelson-Smith, 1973). Feeding behavior such as diving, tipping up, wading, or grazing will affect the degree of contact with oil that a species may experience. Wading birds, such as herons and egrets, may only contaminate their bills and heads which is unlikely to cause death but may produce sublethal effects (Breuel, 1981). Many waterfowl are colonial, and large numbers of birds may be susceptible to even small quantities of oil.



Nesting and resting habitats will also be affected by contact with oil. Loons and grebes, for example, often build floating nests which can easily be contacted by oil. (MMS, 1983a).

Very large numbers of birds, mostly marine birds, die annually as a result of oil pollution from sources other than OCS oil and gas operations. Chronic spills may kill as many as 100,000 birds a year (Nelson-Smith, 1973). Primary concern is not for the individual animal, rather for populations. A single spill event can have devastating effects on bird populations already at low levels and under stress. Some species have low reproductive rates, diminishing prospects for recovery if large numbers of animals are lost.

Oiled birds can be cleaned up, but the success rate varies between 1 and 50 percent (Nelson-Smith, 1973; Breuel, 1981). Even if birds survive, they must be released in time to join their colonies and be reaccepted into the colony's social structure if they are to breed. Sometimes, the cleaning can be as harmful as the oiling due to use of emulsifiers that destroy the natural water repellency of feathers (Clark, 1973).

Marine Turtles

Five species of marine turtles occur in OCS planning areas. Three species, the Kemp's Ridley, the Leatherback, and the Hawksbill, are endangered in all areas. One species, the Green, is listed as endangered in Florida and California but is considered threatened in other areas. The remaining species, the Loggerhead, is considered threatened in all areas. These marine turtles (except the Hawksbill) occur primarily in the warmer waters of the South Atlantic and Gulf of Mexico planning areas and are occasionally sighted in the waters of the southern California planning area. In addition, they occasionally occur in the more temperate waters of the North Atlantic and Pacific coasts during the summer (Fritts et al., 1983; MMS, 1983a).

The effects of oil on marine turtles are not well documented. Ingestion of spilled oil and tarballs has been involved in the deaths of a number of sea turtles (Witham, 1983). Most dead turtles have been recovered from the Atlantic Coast of Florida. Ingested tar was found in their stomachs. Based upon their analyses, Hall, Belisle, and Sileo (1983) proposed that the tar apparently sealed the mouths of the turtles and interfered with normal feeding. Mortality of marine turtles in the western Gulf of Mexico appears to be significantly higher than in the eastern waters, partially a result of incidental catch by shrimp trawlers (Fritts et al., 1983).

The life histories of marine turtles are poorly known. However, nearly all marine turtle sightings are on the nearshore continental shelf (Fritts et al., 1983; Winn, 1982).

Adult turtles returning to nesting beaches are guided by olfactory stimuli associated with the beach where they were born. In the nest, young turtles become imprinted with chemical cues which are detected through permeable eggshell. An oil spill which fouls a nesting beach might disturb the imprinting process in hatching turtles or confuse the return migration of adults to lay eggs. Geraci and St. Aubin (1983) proposed that the impact on reproductive success could be significant. Field experiments in which paired subsamples of turtle eggs were incubated in clean and oil-contaminated sand did not document any significant effects on hatching success or hatchling development. Laboratory experiments utilizing sands treated with varied amounts of crude oil at the initiation of incubation demonstrated no effect on survival, but did cause detectable differences in hatchling morphology. Laboratory experiments in which the oil was added repeatedly during incubation caused significantly reduced survival of embryos and significant differences in hatching times and hatching morphology. Petroleum which has been aged and weathered prior to contacting turtle embryos is less toxic than fresh petroleum. The aged oil found on beaches during actual field experiments produced no detectable effects (Fritts and McGehee, 1982; Lutcavage, Lutz, and Odell, 1984). It is likely that oil spills washed up on nesting beaches will be significantly weathered.

Other possible consequences of spilled oil fouling of turtles in the open ocean include irritation and damage to sensitive periocular tissues and other exposed mucous membranes (Geraci and St. Aubin, 1983). Oil coating the head and eyes could also affect the orbital salt glands which are important in osmoregulation and other physiological processes (MMS, 1983b). High concentrations of hydrocarbons have been found in tissues taken from turtles after exposure to oil. This may reflect an inability to metabolize and eliminate these toxic materials, or perhaps result from their relatively slow metabolic rate (Hall, Belisle, and Sileo, 1983).

Since many turtle species feed on hard-bottom organisms, they may be attracted to the reef-like communities which develop on oil rig support structures. As a result, they may be exposed directly to operational discharges.

The most frequently used oil spill cleanup techniques include the use of mechanical collection and burning. With the exception of burning, and assuming the use of low toxicity dispersants when dispersants are used, the effects of cleanup operations on turtles are probably no worse than those from an oil spill.

In conclusion, the probability of juvenile and adult turtles encountering spilled oil from OCS operations in the open ocean is low. This is due primarily to the low frequency of oil spills resulting from OCS operations as well as the relatively small number and wide distribution of sea turtles. They are, however, threatened or endangered species and are accorded special protection status by legislative mandate. The low numbers of animals also make contact with oil, however improbable, a threat to the species. The impact of oil spills would also become significant during the spring and summer congregation of marine turtles to mate and eventually lay eggs at nesting beaches. As noted previously, the probability of oil being weathered prior to contacting nesting beaches is high. This would greatly reduce the toxic effects on developing eggs and hatchlings.

Marine Mammals

Although whales and other cetaceans are marine mammals, the effects of oil on them are discussed separately. Below, we consider only the potential effects



of oil on pinnipeds (seals, sea lions, and walruses), sea otters, polar bears, and the only sirenian (sea cow) that occurs in or near U.S. OCS waters (mainly off Florida). As described in the "whales" section, endangered marine mammals have commanded extensive attention and research on the likely effects to them resulting from oil spills and other OCS activity-related impacts. It is, therefore, relevant to note that the California population of sea otters (Enhydra lutris) is listed as threatened, whereas the northern or Alaska population is not, and that the sirenian, the West Indian manatee (Trichechus manatus), is listed as endangered. Furthermore, the Guadalupe fur seal (Arctocephalus townsendi) and the North Pacific fur seal (Callorhinus ursinus) are currently being considered for listing, while the Hawaiian monk seal (Monachus schauinslandi) is already listed as endangered. The last named is not considered in the following discussions because of the lack of potential OCS activity-related spills where they occur.

Direct contact with spilled oil may cause mortality of some marine mammals and have no apparent long-term effect on others, depending on factors such as species involved, age, and physiological status of the animal. Sea otters, fur seals, and newly born seal pups are likely to suffer direct mortality from oiling through loss of fur/water repellency and subsequent loss of thermoinsulation resulting in hypothermia. Sea otters are probably more sensitive to oiling because they rely entirely on their fur for thermoinsulation, while fur seals and other pinniped pups possess some subdermal fat layers--depending on age and physiological status. Adult harbor, ribbon, and spotted seals and walrus are likely to suffer some temporary adverse effects such as eye and skin irritation, with possible infection. Such effects may increase physiological stress and perhaps contribute to the death of some individuals (Geraci and Smith, 1976; Geraci and St. Aubin, 1980). Deaths attributable to oiling are more likely to occur during periods of natural stress--during molting, and times of fasting, food scarcity, and disease infestations. The few recorded mammals deaths attributed to oil spills in case histories occurred during winter months (Duval, Martin, and Fing, 1981), a season of increased natural stress.

Oil spill contact with marine mammals could interfere with olfactory sense. Hydrocarbons in the water column or in sediments could affect possible chemoreception in marine mammals. Oiling of pinniped fur may mask olfactory recognition of young pups by nursing females. The sense of smell has been reported to be important in harbor seal mother/pup bonds (Renouf, Lawson, and Gaborko, 1983) and probably is important in other seals. Benthic feeders such as walrus may rely on chemoreception for locating food. Contamination of bottom sediments may interfere with prey identification in contaminated habitats.

Oil ingestion by marine mammals through grooming, nursing, or consumption of contaminated prey could have pathological effects, depending on the species and physiological state of the animal. Although literature indicates that ringed seals, and probably other pinnipeds, rapidly absorb oil in body fluids and tissues (Geraci and St. Aubin, 1980), ingestion of relatively large quantities of oil for a short period of time showed no apparent acute organ damage (Geraci and Smith, 1976). However, with longer periods of ingestion, accumulation could increase. Oil ingestion may have serious acute effects on polar bears. Engelhardt (1981) reported the deaths of two polar bears due to renal failure and red blood cell production dysfunction after the bears were heavily coated with crude oil and subsequently ingested large amounts of oil while grooming.

Review of oil spill case histories (Duval, Martin, and Fing, 1981) indicates that pinnipeds were contaminated following several oil spills. These accounts strongly suggest that marine mammals are not likely to avoid oil spills in all situations. Thus, if an oil spill contacts high-density pinniped habitat areas or seal and sea lion rookeries and major haulout areas during the pupping and breeding season, a few to several thousand individuals could be contaminated and suffer the above effects. Contact with oil may also cause marine mammals to at least avoid or abandon specific habitat areas, such as haulout sites and rookeries, which become contaminated.

Indirect consequences of oil pollution on marine mammals could be associated with changes in availability or suitability of various food sources. Toxic pollutant levels from oil spills and other industrial discharges that are concentrated enough to cause large-scale dieoffs of prey could occur near the immediate spill site or in other localized areas where pollutants have accumulated. Toxic pollutant levels from oil may become trapped in sediments and have long-term sublethal effects on prey organisms. These pollutants are also more likely to affect localized areas than extensive habitat areas. Sea otters, which live year round within limited home ranges or territories and feed generally on sedentary benthic prey, are probably the species most sensitive to local adverse changes in availability of food sources. If an oil spill contaminated bottom sediments, walrus--which also feed primarily on sedentary benthic organisms--may be affected by possible reduction or contamination of clams or other prey organisms within the wintering habitat areas in Alaska. Oil pollution effects on the pelagic prey of seals, sea lions, and fur seals are likely to temporarily reduce the numbers or availability of these food sources within localized areas near the immediate spill site and in areas where the oil slick is found. Because seals and sea lions are generally very versatile in diet and exhibit highly mobile foraging habits, indirect effects of oil on prey species are likely to have minimal effect on these marine mammal species populations.

According to F. R. Engelhardt (1981, personal communication), no reports exist on the effects of oil on sirenians, even though manatees, in Florida at least, are probably regularly exposed to hydrocarbon emissions from boating operations. The particular herbivorous habit of the sirenians leads to a complete lack of understanding of the influence of petroleum on their diet, bioaccumulation factors, effects on digestion, and physiotoxicological responses.

As was the case also for habitat recovery and damage to whales due to oil spill cleanup, these subjects have not been studied relative to other marine mammals. However, the Minerals Management Service contracted in Fiscal Year 1984 for the first part of a two-part study that should ultimately address, at least in part, the potential damage to California sea otters due to oil cleanup. Such studies assume greater importance for this population and other



marine mammals with comparatively small ranges in potentially oil spill-prone areas.

Whales

The protection and conservation provisions of the Marine Mammal Protection Act (16 U.S.C. 1361-1407) apply to all marine mammals, including all cetaceans (whales, dolphins, and porpoises). The often more restrictive provisions of the Endangered Species Act (ESA) (16 U.S.C. 1531-1543) apply, among cetaceans and within waters under U.S. jurisdiction, only to eight species of "great whales." These endangered whales include the bowhead (Balaena mysticetus), right (Eubalaena glacialis), humpback (Megaptera novaeangliae), gray (Eschrichtius robustus), blue (Balaenoptera musculus), fin (B. physalus), sei (B. borealis), and sperm (Physeter catadon). Only the last named whale has teeth; the others all have baleen for feeding. To varying degrees, these species occur, at least seasonally, in most OCS Regions except the Gulf of Mexico, which has generally sparse whale representation. The bowhead occurs only in the Alaska Region; the gray, in the Alaska and Pacific Regions. A small porpoise, the cochito (Phocoena sinus), is being considered for listing as endangered, but it is unlikely to be subjected to oil spills in U.S. OCS waters because it occurs only in the Gulf of California.

Effects of oil on whales have been studied meagerly and often indirectly, and the studies have focused mainly on endangered baleen whales because of their perceived greater sensitivity or "visibility" under the ESA, particularly its section 7 on Interagency Cooperation. Section 7 requires that a Federal Agency insure that any action it authorizes, funds, or conducts is not likely to jeopardize the continued existence of listed species or results in the destruction or adverse modification of their critical habitat. The Minerals Management Service (MMS) Environmental Studies Program contracted most of the studies noted below to answer questions raised during the section 7 consultation process. The study results may also apply, with reservations, to many nonendangered cetaceans, such as minke (baleen) whales (Balaenoptera acutorostrata), Bryde's (baleen) whales (B. edeni), beluga (Delphinapterus leucas), and other smaller toothed whales, dolphins, and porpoises. The effects of oil on listed noncetacean endangered and threatened species are discussed in the "Marine Mammals" section.

Oil may directly affect whales themselves or indirectly affect them through their food resources. No studies have documented such indirect effects as contamination of the whales' food supply owing to the lack of opportunities to investigate them.

Whales occupy surface waters to breathe, and some to feed, potentially exposing them to spilled oil and contact, inhalation, or ingestion (Geraci and St. Aubin, 1982). Geraci and St. Aubin (1982) performed oil detection experiments on dolphins in a controlled environment and on free-ranging gray whales. It was determined that during daylight and under optimum conditions of light and water clarity, dolphins could detect a thick film of dark crude oil within certain characteristics. The controlled experiment, although not directly related to baleen whales since echolocation has not been demonstrated in these species, also suggests that a dolphin using echolocation alone can detect a patch of heavy oil, particularly if the heavy oil contains air bubbles as a result of churning by wind and waves. At sea, the response of dolphins and whales might be modified by social interactions, feeding, agonistic behavior, migration, or human activity. Geraci and St. Aubin (1982) also reported on the reaction of migrating gray whales to naturally occurring oil seeps. Swimming speeds, surfacing and diving times, and respiratory rates were compared relative to the presence and extent of oil. Typically, the whales were observed swimming through the oil at a modified speed, but without a consistent pattern, although some changes in respiration behavior were observed. In oiled waters, the whales seemed to spend less time at the surface, blowing less frequently but at a faster rate. If this reaction is interpreted as an avoidance response, it suggests that gray whales can detect oil. Whales showing no response either could not detect the amount or type of oil present or were indifferent to it. No comparable studies have been conducted on other baleen whales.

Laboratory studies with dolphin skin have revealed the skin exposure to gasoline and crude oil showed no gross evidence of damage or loss of integrity (Geraci and St. Aubin, 1982). Although skin turned a pale gray in color, it returned to normal color within 2 hours. Other surface contact studies by the same authors involved the progress of healing of oil-contaminated as opposed to uncontaminated cetacean wounds, and studies of skin to determine functional changes were reversible even after an exposure of 75 minutes. Albert (1981) speculated that crude oil may adhere to roughened areas of bowhead skin. By analogy, this could also be true for right whales, but no evidence exists to document harmful effects.

Field observations of at least one instance of possible contact of gray whales with spilled oil did not show evidence of extreme effects. In 1969, the entire northward migration of gray whales passed through or near the area contaminated by the Santa Barbara Channel spill. However, the number of gray whale strandings was not significantly different from previous years (Brownell, 1971).

The typical breathing cycle of cetaceans involves an "explosive" exhalation followed by an immediate inhalation of water and should be discriminatory of gas condensates and oil; however, toxic hydrocarbon gas could be inhaled (Geraci and St. Aubin, 1979). Geraci and St. Aubin (1982) calculated likely concentrations of toxic vapors over any oil spill. They concluded that toxic vapors are not likely to reach harmful levels and were not likely to affect whales adversely unless they are confined in the spill. No respiratory problems are expected from exposure to weathered oil. The effects of gas condensate or gas vapor inhalation on cetaceans are unknown. Albert (1981) suggested that tactile hairs around the blowhole of the bowhead whale function as sensory structures, and if spilled oil did adhere to these tactile hairs the sensory function could be compromised. Albert (1981) speculated that the blowhole tactile hairs may provide a sensory means for the whale to detect when the blowhole area is above the water surface.

Geraci and St. Aubin (1982) reported that ingested petroleum could be fatal if even small quantities are regurgitated and aspirated into the lungs. However, cetaceans are uniquely protected by an anatomical adaption of the larynx that



reduces or eliminates the possibility of aspirating regurgitated material. Food organisms can accumulate certain petroleum fractions, which are transferred in turn to cetaceans. However, the effects of such residues on marine mammals are not known. Cetaceans have enzymes which, when stimulated, are capable of detoxifying ingested oil. Albert (1981) speculated that oil ingested by a bowhead whale may hinder the digestive process, compromise the immune system resulting in decreased disease resistance, and cause a mechanical blockage in the form of large blobs of oil and baleen "hair balls" in the connecting channel between the two chambers of the stomach. Still, no studies have documented the physiological effects of ingested oil.

Fouling of baleen and subsequent decreases in feeding efficiency has been cited as another potential direct effect of spilled oil on baleen whales. The probability of such fouling and effects on feeding efficiency are directly linked to probabilities of spills and whale contact with such spills while feeding. Braithwaite, Aley, and Slater (1983) demonstrated average reduction of bowhead baleen filtering efficiencies of 5.9 to 11.5 percent if fouled with oil. How this reduction in filtering efficiency would affect an individual whale's overall health or energy acquisition is not known.

Baleen plates fouled with 10 millimeters of Prudhoe Bay crude oil showed a decrease in filtering efficiency for at least as long as 30 days when tested at 4 to 7°C. However, after approximately 8 hours, the filtration efficiency increased as the baleen hairs did not tend to stick to one another as much. Geraci and St. Aubin (1982) conducted fouling studies on fin and gray whale baleen plates and showed that although filtering efficiency of baleen was temporarily reduced by crude oil for up to 15 minutes, normal flow patterns were restored. These observations essentially alleviate the concern that crude oil would irreversibly obstruct water flow through baleen. However, it is unknown whether the persistence of oil on the fibers would contaminate food sources or cause them to adhere permanently. Prolonged impairment caused by repeated fouling might affect feeding activity.

Albert (1981) speculated that a bowhead whale would likely undergo ocular irritation as a result of contact with oil. The irritation would likely lead to reduced vision and eye mobility. However, no definitive data exist to substantiate this claim.

Habitat recovery and damage due to cleanup relative to oil on whales have not been studied. However, the former is not considered to be significant because a spill would occupy such a small part of most whales' habitat that any effect would be too localized and short-lived to have any long-term or measurable impact on them. Potential damage due to cleanup is considered equally unlikely because few whales would remain in the affected area during cleanup. An exception exists, however, if a significant part of a migrating population were to have to pass through a confined geographic area undergoing cleanup. Such effects are not currently known, under study, or under evaluation except in sale specific impact analyses of areas where such migration may occur (MMS, 1984).

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## Sensitivity to Other Impact-Producing Factors

The preceding papers focused on the potential impacts to various habitats and biota that could be caused by spilled oil. Other potential impact-producing factors were also considered. These are:

1. Drilling discharges (muds, cuttings, and produced waters).
2. Noise generated by OCS activities.
3. Habitat alteration from the installation of OCS facilities.
4. Air emissions from OCS operations.

The following discussions summarize existing information on the effects of these factors. These potential effects are singularly more limited in extent than the potential effects of a large oil spill. However, the cumulative effects of these factors may be more extensive and long lasting than the effects of a large oil spill. The Department of the Interior and other Federal, State, or local agencies have means available to mitigate many of the adverse effects of these factors. As a result, spilled oil remains the factor of greatest concern in this analysis.

## Drilling Discharges

### Muds and Cuttings

Drilling muds and cuttings may be discharged nearly continuously in small quantities while drilling is underway during exploration. Larger discharges may occur several times during the 2 to 6 months usually required to drill a well and a few times at the end of drilling. The total amount of dry solids discharged over the life of an exploratory well is approximately 2,000 tons or 1,000 cubic meters of material. The quantity of drilling muds discharged during development drilling may be as much as 25 percent less than exploration discharges because development wells are normally shallower and smaller in diameter, and some of the mud is recycled for additional well drilling. These muds are typically a mixture primarily of barite and clay, with small amounts of lignosulfonate, lignite, sodium hydroxide and various additives, including diesel fuel which is used as a lubricity agent.

The physical fates of discharged drilling muds and cuttings vary widely as a function of the water depth, ice cover, waves, currents, and general hydrodynamic features of the OCS area. On the OCS, horizontal turbulent diffusion results in dilution of discharge plumes by a factor of 10,000 or more within an hour of release. The concentration of suspended components is reduced significantly from settling (National Research Council (NRC), 1983; Dames and Moore, 1978). While dilution may be inhomogeneous at thermoclines or pycnoclines, the high dilutions predicted in mathematical models have been confirmed by field studies. Theoretical considerations and empirical observations yield the same values for dispersion rates in the water column (NRC, 1983). This results in plume concentrations of suspended particulates which approach background levels (less than 10 mg/l) anywhere from a few hundred to a few thousand meters from the discharge. In the benthic environment, the resuspension and transport of deposited drilling discharge components also reduce the concentrations of the drilling muds.

More than 96 percent of more than 20 whole drilling fluids tested in short-term experiments (from 44 to 144 hours) had LC50 values greater than 1,000 ppm (1 ppm is roughly equivalent to 1 mg/l) and are classified as "slightly toxic" or "practically non-toxic" by the Intergovernmental Maritime Consultative Organization et al. (1969). The National Research Council (1983) reported that the results of toxicity tests also indicate that organisms from all Regions have about the same sensitivity to drilling fluids. More than 60 species from 5 phyla have been used in the studies reviewed by the National Research Council. Recent studies (Conklin et al., 1983; Duke et al., 1984) indicate that the presence of diesel-like hydrocarbons in drilling muds may contribute significantly to the toxicity of the mud.

The concentrations of mud necessary to produce the type of effects observed in laboratory experiments (burial, avoidance) are encountered only very near the discharge. The concentrations necessary to produce effects on adults occur only within a few meters of the discharge. The concentrations necessary to produce effects on larvae occur only within several hundred meters of the discharge. Because of the rapid dilution of the discharge plume, a toxic



response in organisms would be anticipated only if short-term exposures would produce acute effects with concentrations of drilling muds less than 100 ppm. Very few experiments, and those usually long-term (96 hours), have identified lethal or sublethal effects at these concentrations (National Research Council, 1983). Houghton et al. (1981), concluded that likelihood of significant impacts on plankton and nekton in dynamic areas such as Cook Inlet and Georges Bank was low because of the low toxicity of discharged drilling muds and the relatively high dispersion rates. The National Research Council (1983) concluded that because the effects of drilling fluids are largely physical, recovery times should be similar to those following other physical seabed disturbances. These times vary widely; recovery may take weeks in frequently disturbed shallow communities to years in continental shelf and slope communities. The NRC (1983) concluded that long-lived communities which are characteristic of hard substrate epibiota, may be particularly susceptible to long-term effects if they are exposed to large concentrations of deposited muds and cuttings, but many of these communities are not very likely to accumulate such materials unless the materials are deposited directly on them. In the study of impacts of drilling muds on benthic infaunal communities in the Georges Bank area, Battelle (1984) concluded that no significant changes in benthic community structure could be detected which could be attributed to the drilling of eight wells.

There have been a number of laboratory investigations that show that some heavy metals in drilling fluids are bioavailable to marine organisms (Brannon and Rao, 1979; Carr et al., 1982; Gerber et al., 1981; Liss et al, 1980; and others). Liss et al. (1980), have found higher concentrations of chromium and barium in filtrates of seawater suspensions of drilling fluids than would be predicted; this may be the fraction bioaccumulated by marine organisms.

A study of an exploratory drilling discharge in the Baltimore Canyon off New Jersey found statistically significant elevated concentrations of barium and chromium in some samples of mixed-species assemblages of brittle stars, molluscs, and polychaetes collected approximately 2 weeks and 1 year after drilling had ceased (EG&G Environmental Consultants, 1982). No statistically significant increases in mercury levels in biota were found. Payne et al. (1982), could find no indication of any increase in the concentration of barium, chromium, or several other heavy metals in the tissues of bivalve molluscs *Arctica islandica* or of demersal fish near exploratory drilling on Georges Bank.

The National Research Council (1983) stated that field results tend to corroborate laboratory findings that accumulation of heavy metals from drilling muds by organisms is very low. The metals of concern are typically in the form of an insoluble inorganic sulfide or sulfate (MacDonald, 1982), although chromium is associated with lignosulfonate. Heavy metals in the form of insoluble sulfides, adsorbed to particulates, or in the form of nonlabile organic complexes, have a much lower bioavailability to marine animals than do metal ions in solution (Breteler et al., 1981; Bryan, 1982; Jenne and Luoma, 1977; Neff et al., 1978).

The National Research Council (1983) observed that high levels of metal in a sediment or drilling fluid sample are not by themselves an indication of a biological hazard because these adsorbed metals have very limited biavailability. Moreover, the limited metal accumulation observed in laboratory and field investigations suggest that the biological effects of this accumulation are minimal.

While hazard assessments have been and will be developed based on extrapolation of results from sublethal tests, it should be noted that there are no well-established relationships between realistic exposure intervals and the responses elicited over longer periods. Extrapolation is necessary because the experiments conducted did not simulate the rapid dispersion of drilling fluids nor their movement along the bottom.

In conclusion, the National Research Council (1983) found that ". . . the environmental risks of exploratory drilling discharges to most OCS communities are small." However, ". . . uncertainties regarding effects still exist for low energy depositional environments, should they experience large inputs of drilling discharges over long periods of time." The impacts from development drilling are probably less than additive, and the results from exploratory rig monitoring are probably a reasonable indication that significant impacts are not likely to occur on the OCS.

After a review of the comprehensive literature describing the fates and effects of drilling muds discharged into the marine environment, it was determined that the development of the oil and gas resources in the proposed 5-year leasing program will not have significant, large-scale negative impacts on OCS marine ecosystems in any of the planning areas. This determination is based on discussions contained within lease-sale-specific EIS's, recommendations, and conclusions from various technical and policy workshops, the deliberations of the NRC's Marine Board Panel on the Assessment of Fates and Effects of Drilling Fluids and Cuttings in the Marine Environment, and the Interagency Committee on Ocean Pollution Research, Development and Monitoring draft report on the Long-Term Effects of Oil and Gas Development. These discussions include the results from the monitoring of exploratory rig drilling mud discharges in the North Atlantic, Mid-Atlantic, Western Gulf of Mexico, Southern California, and the Alaskan OCS which have supported the general belief that open-ocean discharges will be rapidly dispersed and have minimal effects on biota (Battelle, 1984; Ecomar, 1978; Ecomar, 1983; Dames and Moore, 1978).

Produced Waters

"Formation" or "produced" waters are those waters and particulate matter associated with oil and gas producing formations. The amount of produced water generated is primarily dependent on the method of oil production, field characteristics, and location. Water may also leak into the oil formation from shallower strata through leaky casings or faulty completion. This water may also find its way back to the surface as produced water. As oil and gas production decline, most wells produce increasing amounts of free water, with other fields producing as much as 95 percent water and 5 percent oil and gas. In 1970, daily production (onshore and offshore) of produced water in the United States was 1 trillion gallons with about 399.4 billion gallons of oil (Collins, 1975). In the northwestern Gulf of Mexico, an estimated



12.6 million gallons of produced water per day were discharged to OCS waters (Gianessi and Arnold, 1982). An additional 12.4 million gallons per day were treated onshore and discharged to coastal waters (Brooks, Bernard, and Sackett, 1977). The produced water discharged from a single platform usually is less than about 400,000 gallons per day, whereas discharges from large facilities handling several platforms may be as high as 6.6 million gallons per day (Menzie, 1982). The oil/water mixture produced from the well is either treated on the platform or transported to shore by pipeline to an onshore treatment plant. Typically, the oil and water phases are allowed to separate in a gravity separator, and the water is further treated to remove additional dispersed oil so that it satisfies EPA guidelines before being discharged. Treatment is designed to remove particulates and dispersed oil but has little effect on dissolved hydrocarbons and metal ions (Jackson et al., 1981; Lysyj et al., 1981; Lysyj, 1982).

Produced waters may be high in total dissolved solids (salinity), oxygen demanding wastes, and toxic metals, in addition to oil and grease contaminants (U.S. EPA, 1975). Aromatic hydrocarbons have been measured at the part per million level in various programs in the Gulf of Mexico (Middleditch, 1984). The following metals have been reported at significantly enhanced levels in produced waters: antimony, arsenic, barium, beryllium, cadmium, chromium, copper, iron, lead, manganese, mercury, nickel, silver, strontium, thallium, and zinc (Collins, 1975; Middleditch, 1983). Additionally, high concentrations of naturally occurring radionuclides are found in formation waters (Ried, 1983).

Dilution of formation waters discharged occurs rapidly, with the rate a function of the salinity, current speed, vertical convective mixing of the water column and the water depth. Several field studies (Armstrong et al., 1979; Lysyj et al., 1981; Neff, Marum, and Warner, 1983) have reported dilutions in total hydrocarbons ranging from 500 to 3,000-fold within 1,000 meters of the produced water discharge. Anikouchine (1984) predicted that even with the high dilution, deposition of metal-rich particulates originating in, or from contact with, discharged formation water would increase metal concentrations in sediments above ambient levels in the Point Arguello, California, areas.

Nine species of marine/estuarine organisms have been used in acute lethal bioassays using produced waters. Eighty-six percent of the LC50 values were above 10,000 ppm produced water in seawater (Rose and Ward, 1981; Andreasen and Spears, 1983; Zein-Eldin and Keney, 1979). The most toxic sample had an LC50 of 1,750 ppm which was attributed to the presence of biocides (Zein-Eldin and Keney, 1979). The toxicity of brines from Texas and Louisiana salt domes was evaluated (NOAA, 1978) and found to be not significantly more toxic than an artificial hypersaline solution prepared with artificial sea salts, suggesting that formation water brines have no particular additives which contribute to their toxicity. Produced waters also have varying amounts of phenols, amino acids, fatty acids, other organic acids, alcohols, and naphthenic and humic substances (Collins, 1975; Lysyj, 1982). The toxicity of these substances to marine organisms is not known. Laboratory bioassays (Zein-Eldin and Keney, 1979; Rose and Ward, 1981) and field studies with caged fish (Workman and Jones, 1979) indicate that produced water is significantly more toxic when biocides are being used.

The most sensitive organism evaluated by Rose and Ward (1981) was larval brown shrimp. The LC50 ranged from 160,000 ppm at 3 hours to 8,000 ppm at 48 hours. Rose and Ward (1981) applied a conservative application factor of 0.01 to these values and compared the resulting limiting permissible concentrations of produced water (the estimated highest concentration causing no adverse biological impacts) to the estimated concentrations of produced water in the ocean at different times after discharge, based on a conservative use of the dispersion model developed for vertically distributed pollutants in the Buccaneer Field (Smedes, Herbst, and Calman, 1981). The limiting permissible concentration or produced water was approximately four orders of magnitude greater than the estimated environmental concentration of formation water at all times. The authors concluded that discharge of formation water does not represent a potential hazard to water column organisms drifting or swimming through the wastewater plume.

Bascom (1983) suggested that inorganic metals in the sea are not a hazard to marine animals because they quickly precipitate or adsorb to particulate matter and settle to the bottom in a form that is not readily available or toxic to marine organisms. Little information is available about the chemical forms of metals in produced waters and the chemical transformations that take place when produced water is discharged to the oceans. The MMS (1983) concluded that radionuclides would not present a hazard to human health or the environment because of the rapid dilution of formation waters when discharged on the OCS.

Middleditch (1984) combined predictive and observational strategies to describe the ecological effects of produced water effluents and concluded that current practices for the disposal of produced waters are ecologically sound.

In summary, produced waters are not expected to produce a significant impact in open waters because of the rapid dilution that occurs. In shallow coastal waters where residence times may be higher and flushing rates lower, such discharges may impact benthic organisms. In those cases, only local impacts are to be expected.



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*Study sponsored by the OCS Environmental Studies Program.



## Noise

Airborne and waterborne noises generated by OCS activities, unless controlled of their effects mitigated, may severely adversely affect the behavior and vital activities of endangered/threatened and nonendangered/nonthreatened whales, other marine mammals, and marine, coastal, and migratory birds. Major sources of mobile OCS airborne noise disturbance include low-flying aircraft, high-speed motorboats, and on-ice vehicular traffic associated with ice roads and over-ice seismic operations in the Arctic, as well as other high-frequency, high-pitched sounds. Major stationary sources of airborne noise include artificial island construction, dredging, and drilling. Major sources of waterborne OCS noise include open-water seismic operations, aircraft, drill rigs, dredges, support vessels, pipeline construction, and production and processing facilities. In some cases, these noises may potentially jeopardize the continued existence of some of the animals and birds mentioned earlier by interfering with or disrupting such critical activities as feeding, mating, birthing, nesting, migrating, and resting.

In all cases, the MMS can and does control or otherwise influence the sources of these noises through operating orders and regulations, sale-specific stipulations and Information to Lessees clauses, regional or areawide Notices to Lessees and Operators, and conditions accompanying MMS-issued permits or approvals to conduct specific activities. Because of these controls and mitigative measures, noise is not considered to have significant large-scale negative impacts on these animals and birds.

The remainder of this section details examples of noise and their effects of the parts of marine biota mentioned earlier. Ljungblad et al. (1980, 1981, 1982, and 1983) have been conducting aerial surveys of the Alaskan Beaufort Sea to determine the distribution and abundance of bowhead whales. Part of this effort (Reeves, Ljungblad, and Clarke, 1983) has been to monitor the effect of operating seismic boats on the behavior of the bowhead whale as it migrates westward in the Alaskan Beaufort Sea. In 1981, 3 incidents of seismic sounds were recorded in the presence of a total of 126 whales ranging from 9 to 157 km from operating seismic boats. There was no flight reaction by bowhead whales to seismic sounds.

Gales (1982) studied effects of sound on marine mammals including whales. The available scientific literature was surveyed for data on noise from oil platforms and on hearing capabilities of marine mammals. Data on animal behavior around the platforms was collected by field observations and interviews. The noise from platforms was measured at various geographical locations and analyzed. Evaluation of the combined data indicates that certain platforms are relatively quiet; thus, platforms with minimal sound emission can be designed. The highest level components of the noise from oil platforms are below a frequency of 100 Hz. The distances at which large whales can detect such noise were estimated for various geographical locations. It is unlikely that platform noise will interfere with echolocation of marine mammals, and according to anecdotal information, whales ignore or easily avoid the platforms.

Fraker et al. (1980, 1981), and Richardson et al. (1983, 1984), have studied the effect of noise associated with OCS activities on the behavior of the bowhead whale. These activities included boat and aircraft traffic, seismic exploration, drilling, and dredging. The study area was the Canadian Beaufort Sea which is the summering area for the bowhead whale. The results showed that the behavior of bowhead whales can be affected markedly by the close approach of boats (2 to 3 km) and aircraft (610 m). However, the whales seem to return to their normal activities soon after the boat or plane moved away. The results showed quite clearly and consistently that summering bowheads normally do not swim away from seismic vessels operating 6 or more km away. There was no consistent identification of unusual behavior among bowhead whales observed within 20 km of drillships. Bowhead whales have been frequently within 5 km of dredging operations.

Malme et al. (1983), studied the potential effect of noise associated with OCS activities on the behavior of migrating gray whales. The experimental design included the playback of prerecorded sounds and the actual operation of full-scale seismic exploration air gun systems. The playback experiments included the following prerecorded sounds: drillship, semisubmersible drill rig, drilling platform, production platform, and helicopter. Experiments were conducted with a seismic boat operating an air gun array and a research vessel operating a single air gun. The field measurement area was located south of Monterey, California, at Soberanes Point. The results of the first year of study indicated that gray whales responded to playback recordings at less than 200 m from the source, with the exception of drillship sounds which elicited a response at less than 2.7 km. Gray whales responded to the air gun array at less than 5 km from the source, while behavioral responses from the single air gun were observed at less than 1 km from the source.

Stewart, Awbrey, and Evans (1983), conducted playback experiments with beluga whales in the Snake River, Alaska, using sounds recorded near an operating oil drilling rig. Beluga whale responses to playbacks of oil drilling sounds indicated that direction of whale movement and general activity (feeding, travelling) were not greatly affected by these sounds, especially if the sound source was constant. Whales continued to move in the direction they were travelling before playback began. On several occasions, whales within 2 km of the sound source appeared to feed during playback experiments.

Experiments exposing captive beluga whales to the same sounds (Thomas and Kastelein, 1983) indicated that beluga whales can acclimate quickly to oil-drilling sounds at typical sound levels. This agrees with McCarty's (1981) observations. He reported that beluga whales (including mother-calf pairs) regularly approached to within 10 m of oil production platforms in Cook Inlet. He also reported that as long as noise from these platforms was constant it did not seem to affect beluga whales, but that a sudden change in noise levels elicited a temporary avoidance reaction. Observations also indicate that beluga whales usually respond to sudden acoustic disturbance but are less likely to avoid a constant sound source.

Noise from over-ice seismic operations may displace ringed seals from important denning and pupping habitats. A comparison of ringed seal densities between areas of seismic exploration and areas where no over-ice seismic



activities occurred (using aerial data collected in June 1975 to 1977 to investigate variation in ringed seal distribution) showed a lower density of seals in areas where there had been seismic exploratory activity (Burns, Shapiro, and Fay, 1980). However, such survey data are only an indication of overall survival through the long winter-spring period and provide no insight into the nature, extent, or causes of changes recorded (Burns and Kelly, 1982). Results of surveys conducted in 1981 were ambiguous regarding whether seismic exploration results in displacement of ringed seals (Burns, Kelly, and Frost, 1981). Subsequently, Burns and Kelly (1982), conducted ground examination of ringed seal den structures to determine the fate of such structures along seismic lines and along control lines. The latter investigators reported no significant overall difference in fates of structures between seismic lines and along control lines. However, they reported significant differences in fates of structures in relation to distance from seismic lines (within 150 m of the shot line in comparison to beyond this distance). The investigators concluded that displacement of seals in close proximity (within 150 m) to seismic lines does occur. However, based on data from aerial surveys in 1982, there is no large-scale displacement of seals away from over-ice seismic operations as currently conducted in the Beaufort Sea.

Noise from land-based industrial activities and over-ice seismic operations may also be significant near polar bear dens because female polar bears generally den on coastal terrestrial habitats or on land-fast ice while giving birth and nursing their young. Experience with captive female polar bears suggests that these bears can be especially sensitive to noise and human presence during maternity denning. However, preliminary results of noise measurements taken within a simulated polar bear den suggest that seismic activities would only be detected by denning bears if such activities occurred very near the dens (Burns, personal communication, 1983).

The presence of sea lion, elephant seal, and sea otter populations in close proximity to human development and intensive industrial activity and marine-vessel traffic along the California coast strongly suggests that some marine mammals have adjusted to human development activity with no apparent adverse effects. Playback recordings of industrial noise, and actual seismic sounds from air guns had no apparent effect on California sea otters (Riedman, 1983). However, some species of marine mammals are probably more sensitive to human presence and disturbance, particularly during nursing and breeding seasons. Sensitive species may adjust to human presence and industrial noise to a certain degree, with a portion of the population remaining in disturbed areas. However, noise and disturbance may exceed the tolerance level of sensitive species, eventually displacing this species completely from development areas.

Species such as fur seals, Steller sea lions, and harbor seals that congregate in large social groups for breeding and pupping may be the most sensitive marine mammals to cumulative noise and disturbance. Low-flying aircraft are known to panic hauled out seals. If such disturbance occurs at marine mammal rookeries during the pupping season, a significant increase in pup mortality and reduced pupping success are likely to occur (Johnson, 1977). Disturbed adult seals are likely to crush pups when they stampede into the water, and nursing females are likely to abandon their pups during the first 3 weeks of nursing if disturbance separates the mothers and pups. If seals and sea lions are frequently disturbed during the molting period at haulout areas, the successful regrowth of skin and hair cells may be retarded, thus increasing physiological stress on seals and sea lions during a normally stressful period. Increasing noise and human activity near rookeries, such as on the Pribilof Islands, could exceed the disturbance tolerance level of fur seals and result in the complete or partial abandonment of some rookery or haulout sites on the islands.

Endangered peregrine falcons are likely to be adversely affected by uncontrolled airborne noise and disturbance, especially that associated with supply aircraft serving offshore facilities and potentially passing close to nesting sites. Disturbance from such sources could reduce the survival of nestlings. Noise and human activities attendant with the construction of onshore facilities near peregrine nesting sites could also be a potential source of disturbance.

Marine birds may be severely disturbed by helicopter and vessel traffic to drilling rigs. Onshore air traffic associated with operation of support facilities near seabird colonies and waterfowl and shorebird staging and nesting areas can significantly disrupt breeding activities and preparation for migration. Low-flying aircraft, especially helicopters, can frighten large numbers of cliff-nesting birds (e.g., murres) from the nesting ledges, resulting in displacement of eggs and/or young to the rocks below. Those not displaced from the ledges by adults are left exposed to the elements and predators (Hunt, 1978; Jones and Petersen, 1979). In recent years, repeated aircraft flights near several colonies in the Bering Sea may have been one factor contributing to fewer nesting attempts and reduced reproductive success (Hunt, 1978; Biderman and Drury, 1978). Disturbance of birds in important feeding, staging, and overwintering areas can cause excessive expenditure of energy and displacement to less favorable habitats during critical periods in the annual cycle.



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## Habitat Alteration

The placement of facilities needed for oil and gas operations may result in physical alteration of habitats. The legs of a jackup rig or a fixed production platform and the anchors of a floating platform will disturb bottom sediments and benthic communities. The severity and duration of impacts depend on the local bottom conditions and habitats. Platform installation and anchor placement could damage live hard bottoms or coral reefs or destroy certain fishery habitats, such as tilefish burrows. Rig and platform installation could disturb both surface and buried archaeological sites. However, geophysical surveys required before siting a drilling rig or platform help identify sensitive areas that could suffer adverse or long-term damage so that they can be avoided. In soft-bottom areas, no significant physical damage is likely to result from platform emplacement.

A platform provides substrates for the attachment of biota which attract fish and other animals either to feed or find refuge. The concentration of fish around platforms may represent an increase in the population carrying capacity of those species or a concentration of existing population. Gallaway and Lewbel (1982) support the population enhancement hypothesis for the Gulf of Mexico where the presence of platforms is considered a boon to fishermen. While fisheries population enhancement may occur in other areas, platforms can also restrict certain fishing methods, such as trawling and drift net fishing, that are important in the Atlantic and off California.

Because of ice hazards in the Arctic, gravel islands and causeways are constructed as a base for drilling. These structures permanently bury or displace the benthic community. Offshore dredging for materials for these structures can also result in habitat alteration. However, Boesch et al. (1984), judged all of the long-term effects of constructing gravel islands and causeways in the Arctic to be of low severity.

Pipeline installation also causes considerable disruption to the bottom. Approximately 6 acres of the bottom is physically disturbed per mile of pipeline laid; some 2,300 to 6,000 cubic yards of sediment are resuspended per mile of pipeline, depending on the size of the pipeline and the depth of trenching or burial (MMS, 1983). Added to this is the damage caused by the anchors of the pipelaying barge. Considerable damage could be done if such activities are conducted in sensitive areas.

The siting of pipeline landfalls must account for the presence of sensitive environmental areas which could require long periods of time to recover. These include important habitats such as spawning and nursery areas or shellfish beds. Coastal areas that would be desirable for landfalls would have sandy or firm sediments and be gently sloping (less than 10 percent grade) (Gowen and Goetz, 1981). A pipeline crossing a barrier beach would predispose the landfall site to considerable erosion if the pipeline trench is not carefully backfilled and the area revegetated to reestablish any dunes. Beach erosion can be prevented by burying the pipeline to depths where wave action would not uncover the pipeline and cause scouring (MMS, 1983).



Infrastructure development, especially pipelines and onshore support facilities, can destroy or disrupt wetland habitats permanently. Pipeline emplacement in sensitive coastal habitats, such as wetlands, can result in impacts in the form of marsh loss and changes in salinity regimes. The effects of wetland alterations contribute to extensive and permanent loss of coastal habitats with the attendant loss of biological productivity (MMS, 1983). Boesch et al. (1984), proposed that this is a particular problem in Louisiana where the needs of the oil and gas industry have contributed to this phenomenon. Gonsoulin, Laird, and Wallis (1984) state that although "drilling access and pipeline canals have had the effect of promoting salt water intrusion when canal plugs are not maintained, it is now believed that the levee and flood control structures along the Mississippi and other river systems are the major culprit in the steady subsidence, cutting off the sediment base load and tipping the scales in favor of the erosive forces at work. It is a complex problem that has no simple solutions."

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## Air Emissions

In developing the Clean Air Act, Congress determined that increased air pollution resulted in mounting dangers to the public health and welfare. To define the amount of pollution considered detrimental, Congress directed that the U.S. Environmental Protection Agency (EPA) set national primary and secondary ambient air quality standards (NAAQS) that were sufficient to protect the public health and welfare. The EPA developed NAAQS for carbon monoxide (CO), ozone ($O_3$), nitrogen dioxide ($NO_2$), sulfur dioxide ($SO_2$), total suspended particulates (TSP), lead, and non-methane hydrocarbons.

Air pollutants are emitted from OCS facilities in the form of nitrogen oxides ($NO_x$), $SO_2$, TSP, CO, and volatile organic compounds (VOC). Under certain conditions, $NO_x$ and VOC emissions can contribute to the formation of ozone. Although nearly all OCS operations will result in some emissions of all of these pollutants, activities associated with power generation and transportation and processing of hydrocarbon resources are responsible for the majority of emissions. Power-generative equipment (such as gas turbines and diesel engines needed to run drilling and pumping operations) generally produces the largest amount of pollutants from OCS facilities, with $NO_x$ normally the pollutant emitted in the largest amount. The amount of all pollutants produced depends on the operating characteristics of the engine, such as size, type, period of use, and type of fuel burned. Diesel engines produce the largest amount of emissions of pollutants; gas turbines emit lesser amounts. If oil production is transported to shore by barge or tanker, large amounts of VOC can be emitted by the displacement of hydrocarbon vapors during barge loadings. Vapors remaining in the hold from prior shipments are pushed out into the atmosphere as the hold fills with oil. However, the use of vapor balance lines in such transfer operations would largely reduce hydrocarbon vapor emissions. Normally, production is pumped to shore through pipelines, and such emissions are avoided. However, significant emissions of $SO_2$ from gas processing activities can be avoided by installing tail gas treatment or sulfur recovery units. Large amounts of $SO_2$ can be emitted from facilities producing sour natural gas (gas containing a relatively high concentration of hydrogen sulfide, $H_2S$) that is processed offshore. $SO_2$ emissions resulting from processing sweet gas (low $H_2S$ content) are normally not a problem.

The DOI air quality rules (30 CFR 250.57) provide for the protection of onshore air quality by ensuring that it is not significantly affected by emissions from OCS facilities. The rules require installation of Best Available Control Technology and/or the acquisition of emission offsets if an OCS facility by itself or cumulatively with other OCS facilities in an air basin exceeds 1 to 3 percent of the applicable NAAQS levels that have been designated as significant by DOI. These levels were based on information provided to the Minerals Management Service (MMS) by EPA during the original rulemaking process and have been reaffirmed by EPA since the final promulgation of the rules in March 1980.

Recent EPA rulings (Kentucky vs. Indiana; Interstate Pollution Abatement: Final Determination (47 FR 6625); New York, Pennsylvania and Maine vs. Out of State sources in the Midwest: Interstate Pollution Abatement; Proposed Determination (49 FR 34851) September 4, 1984) and court decisions (Connecticut Fund for the Environment, Inc. vs. EPA, 696 F. 2d at 175, 177 (2d Cir. 1982); Air Pollution Control District vs. EPA, No. 82-3214 (6th Cir. 1984) July 10, 1984) upholding the EPA rulings have ruled that impacts by particular sources located outside the nonattainment area boundaries as high as 5 percent of the applicable NAAQS are not significant impacts.

Past EIS analyses of air quality impacts (Sales 73 and 80 EIS's, Santa Ynez and Point Arguello EIS/environmental impact reports in California, Lease Sale EIS's for Gulf of Mexico (94, 98, 102), and Atlantic (82)) indicate that OCS impacts are less than the DOI significance levels. If future lease sales are similar in scope and proposed level of development, the impacts from these sales will also be less than the DOI significance levels. However, cumulative impacts from OCS development may cause concentrations above the DOI significance levels. Mitigative measures as required by the DOI air quality regulations would prevent significant air quality impacts.

The recent Secretarial Decision Material for air quality for Lease Sale 80 included an analysis of the relative contribution of emissions from OCS facilities to air basin emissions in California. In all cases except emissions of $NO_x$, emissions from OCS facilities were less than 2 percent of total onshore emissions. For $NO_x$, OCS sources contributed approximately 7 percent of total air basin emissions; but the Sale 80 EIS still concluded that cumulative onshore $NO_2$ impacts from OCS activities were less than the DOI significance level (which is 1 percent of the NAAQS for $NO_2$).

Though greater OCS activity occurs in the Gulf of Mexico, the provisions of the DOI rules that impose mitigative measures for sources or groups of sources significantly impacting onshore air quality insure that human health and general welfare will not be adversely impacted by these sources. Impacts to regional visibility have been determined to be insignificant and aesthetic impacts from visible emissions would also be insignificant.

# APPENDIX I-3

## RELATIVE MARINE PRODUCTIVITY AND ENVIRONMENTAL SENSITIVITY

## OIL SPILLS

## EFFECTS OF SUBAREA DEFERRALS

Proposed Final Program:
5-Year Outer Continental Shelf Oil and Gas Leasing Program
for Mid-1987 through Mid-1991

## TABLE OF CONTENTS



## TABLE OF CONTENTS (Continued)

# APPENDIX I-3

## RELATIVE MARINE PRODUCTIVITY AND ENVIRONMENTAL SENSITIVITY

## EFFECTS OF SUBAREA DEFERRALS

### I. Introduction

As required by the Outer Continental Shelf (OCS) Lands Act, as amended, the analysis of relative marine productivity and environmental sensitivity in the Proposed Program (February 1986) focused on the OCS planning areas which the Secretary of the Interior indicated would be the locations of future leasing activities. However, in the Proposed Program, the Secretary also deferred or proposed further study of the deferral of one or more subareas from several of the OCS planning areas. The effects of these deferrals, plus some deferrals proposed by other parties, on the relative marine productivity and environmental sensitivity of the reconfigured planning areas are evaluated in this appendix.

The OCS Lands Act, as amended does not require the Secretary to assess the relative marine productivity and environmental sensitivity of those areas in which he/she does not propose to conduct leasing activities for oil and gas during the period included in the 5-Year schedule. This was demonstrated in the Proposed Program by the lack of such analyses for the Aleutian Arc, Bowers Basin, Aleutian Basin, and St. Matthew-Hall planning areas. The removal of subareas from the OCS planning areas is equivalent to the deletion of entire planning areas from the 5-Year program. With his/her final decision, the Secretary is notifying all concerned parties that oil and gas leasing activities will not occur in these subareas during the period included in the 5-Year schedule. In this regard these subareas become equivalent to the planning areas removed from consideration at the Draft Proposed Program stage and require no further analysis of their relative marine productivity and environmental sensitivity. The Secretary's final decision may reconfigure planning areas if subareas are deferred from future leasing. These reconfigured planning areas are analyzed in this appendix for their relative marine productivity and environmental sensitivity. In the spirit of the Act, these analyses are as precise as possible in assessing the relative marine productivity and environmental sensitivity of the areas in which the Secretary is proposing to conduct future oil and gas leasing activities, not those areas which he has excluded.

In the Proposed Program, the analysis of relative marine productivity and environmental sensitivity was limited to a discussion of the sensitivity of those resources which occurred within the boundaries of the planning areas. Sensitivity was defined as the potential for damage to an ecological resource resulting from its contact with spilled oil. Any reference to vulnerability, which is a positional attribute related to the proximity of a resource to a potential hazard, was avoided in the Proposed Program. As an example, resources near the boundary of a planning area, which might be vulnerable to oil spilled in an adjoining planning area and transported across the boundary between the planning areas, were not included in the



sensitivity calculation for both planning areas. The resources were included only in the calculation for the planning area in which they occurred. Migratory species were counted in every planning area in which they occurred. The present analysis follows the precedent of the analysis of entire planning areas in the Proposed Program.

In Section 18(a)(2)(G) of the OCS Lands Act, as amended, the Secretary is mandated specifically to evaluate the relative environmental sensitivity of the OCS planning areas. While it is possible that Congress did not make the distinction between sensitivity and vulnerability, the wording of Section 18(a)(2)(G) is specific. The analysis of the planning areas in the Proposed Program and the current analysis of the effects of subarea deferrals, specifically address the concept of sensitivity, not vulnerability. The Department is preparing an environmental impact statement (EIS) on the Proposed Program. This document will be available to the Secretary and all interested parties before a final decision on the schedule is made, and will assess all of the environmental consequences, including the vulnerability of coastal and marine resources in areas adjoining the planning areas to contact by oil spilled as a result of oil and gas activities outside their boundaries. More specific analyses are provided routinely in specific lease sale EIS's. It is possible that in drafting the requirement for the analysis of relative marine productivity and environmental sensitivity the Congress recognized that the concept of vulnerability was different from sensitivity, and that the former would be addressed sufficiently in the EIS's required by the National Environmental Policy Act.

### II. Methods

The effects of subarea deferrals on the relative marine productivity and environmental sensitivity of the reconfigured planning areas are evaluated using the same procedures described in the Proposed Program for the entire planning areas (see Appendix I). Scores calculated for planning areas with subarea deferrals are compared to the scores for the entire planning areas provided in the Proposed Final Program. In the following analysis, the total score reported for each deferral alternative is the sum of the scores for the three ecological components remaining within the reconfigured planning area after the removal of the area to be deferred. The planning area is reconfigured with each deferral option. This analytical protocol is consistent with that used in the Proposed Program and with the differentiation between sensitivity and vulnerability discussed above.

In developing the original analysis of relative marine productivity and environmental sensitivity, three ecological components of each planning area were evaluated: coastal habitats, marine habitats, and biota. The results of the original analysis demonstrated the significance of the coastal habitats to the overall total score for the planning areas. The calculation included coastal habitats as a component of the planning areas even though the coastal habitats are separated from the OCS by coastal waters under state jurisdiction. Many of the deferrals described in the Proposed Program include the provision of buffers along coastal sections in several planning areas. These buffers are not of uniform width throughout the planning areas. In the present calculations, the provision of a coastal buffer is assumed to be equivalent to the removal of the immediately adjoining coastal area from the planning area. As a result the scores of many planning areas are reduced significantly from those presented in the Proposed Program.

The removal of the coastal habitats from the calculation of relative environmental sensitivity is not meant to imply that the provision of any proposed buffer area guarantees that oil spilled on the OCS will not contact the coastal habitats. The movement of oil spilled on the OCS is a complex phenomenon which is affected by highly variable oceanographic and atmospheric conditions. Oil spills may be transported across buffer areas by generally prevailing conditions and/or by unique or rare oceanographic and atmospheric events. The provision of a buffer usually provides additional distance which the spill must cross to contact coastal resources. The additional time required for the spill to cross the buffer provides a longer period for the deployment of oil spill contingency equipment and implementation of steps to further protect sensitive resources. The trajectories of oil spilled from selected sites in most planning areas have been modeled by the MMS with results provided in lease sale EIS's. The reader may refer to these statements to evaluate the effects of deferrals on the vulnerability of coastal areas of interest from offshore oil spills.

The scores for relative environmental sensitivity based on the assumption that coastal buffers remove the immediately adjoining coastal habitats from the planning area provide the Secretary with some impression of the relative sensitivity of the remainder of the planning area if those coastal habitats are completely protected. This score provides a measure of the lower limit of relative environmental sensitivity. The scores for the entire planning area assume that all coastal habitats are not protected and provide a measure of the upper limit of relative environmental sensitivity. The most realistic value for the relative marine productivity and environmental sensitivity of the planning area probably lies within this range.

## III. Results

### Atlantic Region Deferrals

Subarea deferrals are proposed in all four planning areas in the Atlantic Region: North Atlantic, Mid-Atlantic, South Atlantic, and Straits of Florida.

### North Atlantic Deferrals

In the proposed program, the North Atlantic Planning Area had a total score of 209 points for relative marine productivity and environmental sensitivity. Four deferral options for the planning area are evaluated in the following discussions: (1) 15-nautical mile coastal buffer, (2) Gulf of Maine, (3) Congressional moratorium area, and (4) the cumulative deferral of all of these areas.



#### 15-Nautical Mile Coastal Buffer

In the Proposed Program, the Secretary highlighted for further study the deferral of a 15-nautical mile coastal buffer throughout the North Atlantic Planning Area. Deferral of this coastal buffer would remove approximately 4.9 million acres of nearshore marine habitat and all of the coastal habitat from the original planning area. The reconfigured planning area would contain approximately 45.7 million acres of marine habitat and no coastal habitat. The net result of the deferral on the score for marine habitats is insignificant. Removal of the coastal habitat produces an 83-point reduction in the score for this ecological component. Based on the assumption that most coastal birds occur in the coastal buffer, the abundance of this group in the reconfigured planning area is rated as low rather than moderate as it was in the original planning area. This results in a 10-point reduction in the score for biota. The net effect of the coastal buffer deferral is a 93-point reduction in the total score for the original planning area. The total score decreases from 209 points for the original planning area to 116 points for the reconfigured planning area (Table I-3.1).

#### Gulf of Maine Deferral

In the Proposed Program, the Secretary highlighted for further study the deferral of the Gulf of Maine. Deferring this subarea would remove appproximately 10.3 million acres of marine habitat and approximately 240 miles of coastal habitat from the original planning area. The reconfigured planning area would contain approximately 40.3 million acres of marine habitat and 193 miles of coastal habitat. Because the Gulf of Maine does not contain large areas of highly sensitive marine habitat or high concentrations of sensitive marine biota which do not occur elsewhere in the reconfigured planning area, the deferral does not significantly reduce the scores for these components. However, the removal of 240 miles of coastal habitat does affect the original planning area's score for this component. The coastal habitat removed as a result of this deferral includes most of the moderate-sensitivity rocky beach habitat in the original planning area. The coastal habitat in the reconfigured planning area is predominantly low-sensitivity sandy beach. As a result of the deferral, the sensitivity score for coastal habitat decreases by 25 points. The net effect of this deferral is a 25-point reduction in the total score for the planning area. The total score decreases from 209 points for the original planning area to 184 points for the reconfigured planning area (Table I-3.2).

#### Congressional Deferral

The "Congressional deferral" would remove approximately 12.8 million acres of marine habitat and approximately 100 miles of coastal habitat from the original planning area. The reconfigured planning area would contain approximately 37.8 million acres of marine habitat and 333 miles of coastal habitat. The area deferred includes some of the most productive and environmentally sensitive marine habitat in the planning area. However, the effects of the deferral are most apparent in the "biota" component because of reductions in the relative abundances of phytoplankton, and juvenile and adult fish and shellfish associated with the Georges Bank. This results in an 18-point reduction in the score for biota. Removal of approximately 100 miles of coastal habitat from the original planning area increases the score for this component because the area removed is predominantly low-sensitivity sandy beach. The percentage of high-sensitivity wetland and moderate-sensitivity rocky beach habitat in the reconfigured planning area (70.4%) is much higher than that of the original planning area (54.4%). The score for coastal habitat increases by 11 points as a result of this deferral. The effect of the "Congressional deferral" is a net reduction of 7 points in the total score for the original planning area. The total score decreases from 209 points for the original planning area to 202 points for the reconfigured planning area (Table I-3.3).

### Cumulative Deferral

This deferral includes all of the three deferrals described previously for the North Atlantic Planning Area. The cumulative deferral would remove approximately 24.5 million acres of marine habitat and all of the coastal habitat from the planning area. The reconfigured planning area would contain approximately 26.1 million acres of marine habitat and no coastal habitat. The separate effects of these deferrals have been described previously. As a result of the cumulative deferral of these areas, the total score for the relative marine productivity and environmental sensitivity of the original planning area decreases by 111 points from 209 points for the original planning area to 98 points for the reconfigured planning area (Table I-3.4).

## Mid-Atlantic Deferrals

In the Proposed Program, the Mid-Atlantic Planning Area had a total score of 198 points for relative marine productivity and environmental sensitivity. Two deferrals from the planning area are combined in the following evaluation: (1) U.S.S. Monitor Marine Sanctuary and buffer zone and (2) 15-nautical mile coastal buffer zone.

Deferral of the U.S.S. Monitor Marine Sanctuary and buffer zone would remove approximately 34,000 acres of marine habitat from the original planning area. In the Proposed Program, the Secretary highlighted for further study the deferral of a 15-nautical mile coastal buffer throughout the Mid-Atlantic Planning Area. Deferral of this coastal buffer would remove an additional 6.8 million acres of nearshore marine habitat and all of the coastal habitat from the original planning area. The reconfigured planning area would contain approximately 75.4 million acres of marine habitat and no coastal habitat. Removal of the marine habitat from the planning area has an insignificant effect on the score for this component. Removal of the coastal habitat produces a 70-point reduction in the score for this ecological component. Based on the assumption that most coastal birds occur in the coastal buffer, the abundance of this group in the reconfigured planning area is rated as low rather than moderate. This produces a 10-point reduction in the score for biota. Deferral of the coastal



buffer produces an 80-point reduction in the total score for the original planning area. The total score decreases from 198 points for the original planning area to 118 points for the reconfigured planning area (Table I-3.5).

## South Atlantic Deferrals

In the Proposed Program, the South Atlantic Planning Area had a total score of 230 points for relative marine productivity and environmental sensitivity. Three deferral options for the planning area are evaluated in the following discussions: (1) 15-nautical mile coastal buffer, (2) NASA Flight Clearance Zone, and (3) the combined deferral of both of these areas.

### 15-Nautical Mile Coastal Buffer

In the Proposed Program, the Secretary highlighted for further study the deferral of a 15-nautical mile coastal buffer throughout the South Atlantic Planning Area. Deferral of the coastal buffer would remove approximately 8.0 million acres of nearshore marine habitat and all of the coastal habitat from the original planning area. The reconfigured planning area would contain approximately 97.8 million acres of marine habitat and no coastal habitat. The deferral of the marine habitat produces an insignificant increase in the score for this ecological component. Removal of the coastal habitat produces an 85-point reduction in the score for this ecological component. Based on the assumption that most coastal birds occur in the coastal buffer, the abundance of this group in the reconfigured planning area is rated as low rather than high as it was in the original planning area. This results in a 20-point reduction in the score for biota. The net effect of the coastal buffer deferral is a 105-point reduction in the total score for the original planning area. The total score decreases from 230 points for the original planning area to 125 points for the reconfigured planning area (Table I-3.6).

### NASA Flight Clearance Zone

In the Proposed Program, the Secretary highlighted for further study the deferral of the NASA Flight Clearance Zone offshore Cape Canaveral, Florida. Deferral of this subarea would remove approximately 19.0 million acres of marine habitat and approximately 160 miles of coastal habitat from the original planning area. The reconfigured planning area would contain approximately 86.8 million acres of marine habitat and 567 miles of coastal habitat. Removal of the marine habitat produces a 0.8-point decrease in the score for this component. The coastal habitat in the reconfigured planning area has the same general composition as that in the original planning area. As a result, the score for coastal habitat is unaffected by the deferral. The deferral does not affect the score for biota. The net effect of this deferral is a 1-point reduction in the total score for the original planning area. The total score decreases from 230 points for the original planning area to 229 points for the reconfigured planning area (Table I-3.7).

## Cumulative Deferral

Deferral of both the 15-nautical mile coastal buffer and the NASA Flight Clearance Zone would remove approximately 27.8 million acres of marine habitat and all of the coastal habitat from the original planning area. The reconfigured planning area would contain approximately 78 million acres of marine habitat and no coastal habitat. Removal of the marine habitat results in a 0.85-point decrease in the score for this component. Removal of all coastal habitat results in an 85-point decrease in the score for this ecological component. An additional 20 points is deducted from the score for biota in the original planning area because of the decrease in the relative abundance of coastal birds in the reconfigured planning area. The net effect of the cumulative deferral is a 106-point reduction in the total score for the planning area. The total score decreases from 230 points for the original planning area to 124 points for the reconfigured planning area (Table I-3.8).

## Straits of Florida Deferrals

In the Proposed Program, the Straits of Florida Planning Area had a total score of 228 points for relative marine productivity and environmental sensitivity. This score was increased to 238 points based on new or revised information. Two deferrals from the planning area are combined in the following discussion: (1) Atlantic Coast subarea and (2) Looe Key and Key Largo National Marine Sanctuaries.

In the Proposed Program, the Secretary proposed the deferral of the Atlantic Coast subarea from the Straits of Florida Planning Area. Deferral of the Atlantic Coast subarea and the Looe Key and Key Largo national Marine Sanctuaries would remove approximately 5.2 million acres of marine habitat and 295 miles of coastal habitat from the original planning area. The reconfigured planning area would contain approximately 4.7 million acres of marine habitat and 150 miles of coastal habitat. Because the area removed from the original planning area is generally less environmentally sensitive than that remaining in the reconfigured planning area, the overall effect of the deferral is an increase in the environmental sensitivity for the reconfigured planning area. Removal of the marine habitat from the original planning area increases the score for this component by 2.49 points in the reconfigured planning area. The reconfigured planning area has a higher percentage of high-sensitivity submerged vegetation and coral reef habitat (7.1%) than the original planning area (5.7%). Removal of the coastal habitat from the original planning area increases the score for this component in the reconfigured planning area by 5.8 points. The reconfigured planning area has a higher percentage of high sensitivity wetlands (67%) and a lower percentage of low-sensitivty sandy beach habitat (33%) than the original planning area (61% and 39%, respectively). The score for biota is unaffected by the deferral. The net effect of the Atlantic Coast subarea deferral and the deferral of the Looe Key and Key Largo National Marine Sanctuary is an increase of 8 points in the total score for the planning area. The total score increases from 238 points for the original planning area to 246 points for the reconfigured planning area (Table I-3.9).



## Gulf of Mexico Region Deferrals

Subarea deferrals are proposed for the Eastern Gulf of Mexico and the Western Gulf of Mexico Planning Areas.

## Eastern Gulf of Mexico Deferrals

In the Proposed Program the Eastern Gulf of Mexico Planning Area had a total score of 208 points for relative marine productivity and environmental sensitivity. The score was reduced to 198 points based on new or revised information. Five deferrals from the Eastern Gulf of Mexico Planning Area are evaluated in the following discussions: (1) Seagrass Beds and Florida Middle Ground, (2) 30-Nautical Mile Buffer, (3) Apalachicola to Panama City subarea, (4) Miami Protraction Diagram subarea, and (5) the cumulative deferral of all of these areas.

### Seagrass Beds and Florida Middle Ground

In the Proposed Program, the Secretary proposed the deferral of the seagrass beds and Florida Middle Ground from the Eastern Gulf of Mexico Planning Area. This deferral would eliminate approximately 0.97 million acres of marine habitat and 257 miles of coastal habitat from the original planning area. The reconfigured planning area would contain approximately 71 million acres of marine habitat and 586 miles of coastal habitat. Removal of the marine habitat from the original planning area reduces the score for this component by 2.37 points. Removal of the coastal habitat reduces the score for this component by 6.4 points. The reconfigured planning area has a higher percentage of low-sensitivity sandy beach habitat (56.5%) and a lower percentage of high-sensitivty wetland habitat (43.5%) than the original planning area (49.4% and 50.6%, respectively). The net effect of this deferral is a reduction of 9 points in the total score for the planning area. The total score decreases from 198 points for the original planning area to 189 points for the reconfigured planning area (Table I-3.10).

### 30-Nautical Mile Coastal Buffer

In the Proposed Program, the Secretary highlighted for further study the deferral of a 20- to 30-nautical mile coastal buffer along most of the Gulf coast of Florida. This analysis focuses on the 30-nautical mile buffer. Implementation of this deferral would remove approximately 17 million acres of marine habitat and 547 miles of coastal habitat from the original planning area. The reconfigured planning area would contain approximately 55 million acres of marine habitat and 137 miles of coastal habitat. Removal of the coastal habitat decreases the score for this component by 45 points because the coastal area in the reconfigured planning area is predominantly low-sensitivity sandy beach habitat. Removal of the marine habitat decreases the score for this component by 5.08 points. The deferral removes most of the sensitive marine habitats from the original planning area. The coastal buffer is assumed to be sufficiently wide to reduce the relative abundance of coastal birds in the reconfigured planning area from moderate to low. This assumption produces a 10-point reduction in the score for the biota component. The result of this deferral is a 61-point reduction in the total score for the original planning area. The total score decreases from 198 points for the original planning area to 137 points for the reconfigured planning area (Table I-3.11).

### Apalachicola to Panama City Subarea

Deferral of the Apalachicola to Panama City Subarea would remove approximately 668,000 acres of nearshore marine habitat and 62 miles of coastal habitat from the original planning area. The reconfigured planning area would contain approximately 71.3 million acres of marine habitat and 622 miles of coastal habitat. Removal of the coastal habitat produces a 4.1-point increase in the score for this ecological component. The percentage of high-sensitivity wetland habitat in the reconfigured planning area (55.1%) is greater than that in the original planning area (50.6%). This increase is accompanied by an equivalent decrease in the percentage of low-sensitivity sandy beach habitat in the reconfigured planning area. The deferral has no effect on the scores for marine habitat or biota. The result of this deferral is a 4-point increase in the total score for the original planning area. The total score increases from 198 points for the original planning area to 202 points for the reconfigured planning area (Table I-3.12).

### Miami Protraction Diagram Deferral

In the Proposed Program, the Secretary highlighted for further analysis the deferral of the subarea south of 26° N. latitude and east of 82° W. longitude in the "Miami" official protraction diagram offshore Florida in the Eastern Gulf of Mexico Planning Area. Implementation of this deferral would remove approximately 1.1 million acres of marine habitat and 161 miles of coastal habitat from the original planning area. The reconfigured planning area would contain approximately 70.9 million acres of marine habitat and 523 miles of coastal habitat. Removal of the marine habitat produces an insignificant decrease in the score for this ecological component. Removal of the coastal habitat produces a 12.3-point decrease in the score for this component. The reconfigured planning area has a much lower percentage of high-sensitivity wetlands (36.9%) and a much higher percentage of low-sensitivity sandy beach habitat (63.1%) than the original planning area (50.6% and 49.4%, respectively). The deferral has no effect on the score for biota. The net effect of the deferral is a 12-point reduction in the total score for the original planning area. The total score decreases from 198 points for the original planning area to 186 points for the reconfigured planning area (Table I-3.13)

### Cumulative Deferral

This deferral includes all of the four deferrals described previously for the Eastern Gulf of Mexico Planning Area. This deferral would remove approximately 19.4 million acres of marine habitat and 591 miles of coastal habitat from the original planning area. The reconfigured planning area would contain approximately 51.6 million acres of marine habitat and 93



miles of coastal habitat. Removal of the coastal habitat produces a 45.5-point reduction in the score for this ecological component. The coastal habitat in the reconfigured planning area is predominantly sandy beach. Removal of the marine habitat produces a 5.66-point reduction in this ecological component. Additionally, the relative abundance of coastal birds in the reconfigured planning area is rated as low rather than moderate as it was in the original planning area. This change produces a 10-point reduction in the score for biota. The result of the cumulative deferral is a reduction of 61 points in the total score for the original planning area. The total score decreases from 198 points for the original planning area to 137 points for the reconfigured planning area (Table I-3.14).

## Western Gulf of Mexico Deferral

In the Proposed Program, the Western Gulf of Mexico Planning Area had a total score of 180 points for relative marine productivity and environmental sensitivity. The Secretary proposed the deferral of the two blocks which contain the Flower Garden Banks from the planning area in the Proposed Program. Deferral of this area would remove approximately 11,500 acres of highly sensitive marine habitat from the original planning area. No coastal habitat would be affected by the deferral. The reconfigured planning area would contain approximately 35.29 million acres of marine habitat and 367 miles of coastal habitat. Removal of the coral reefs produces a 0.05-point reduction in the score for marine habitat. The deferral has no effect on the coastal habitats and biota of the planning area. The deferral of the Flower Garden Banks has no effect on the total score for the Western Gulf of Mexico Planning Area (Table I-3.15).

## Pacific Region Deferrals

Subarea deferrals are proposed for all three California planning areas and the Washington/Oregon Planning Area.

## Southern California Deferrals

In the Proposed Program, the Southern California planning area had a total score of 213 points for relative marine productivity and environmental sensitivity. The score was increased to 219 points based on new or revised information. Six deferrals are evaluated for the Southern California Planning Area in the following discussions: (1) the Secretary's deferrals described in the Proposed Program, (2) the Governor of California's proposed deferral, (3) Congressman Regula's proposed deferral, (4) Congressman Panetta's proposed deferral, (5) the February 1987 Amalgamated Proposal, and (6) the cumulative deferral of all these subareas.

### Secretary's Deferrals

The deferrals identified by the Secretary in the Proposed Program include the subarea off the Santa Barbara Federal Ecological Preserve and Buffer

Zone, the Channel Islands National Marine Sanctuary, and the Coordinated Anti-Submarine Warfare Area. This analysis also includes the subarea beyond the 1000-meter isobath. Deferral of these subareas would remove approximately 13.9 million acres of marine habitat and 288 miles of coastal habitat from the planning area. The reconfigured planning area would contain approximately 16 million acres of marine habitat and 423 miles of coastal habitat. Removal of the coastal habitat from the original planning area results in an 8.5-point decrease in the score for this component. Removal of the marine habitat produces a slight increase in the score for this component because the area occupied by submerged vegetation increases from 0.43% in the original planning area to 0.75% in the reconfigured planning area. The score for biota is not changed as a result of this deferral. The net result of this deferral is an 8-point reduction in the total score for the original planning area. The total score decreases from 219 points for the original planning area to 211 points for the reconfigured planning area (Table I-3.16).

Governor's Proposal

The Governor of California proposed the deferral of 64 subareas from the Southern California Planning Area. These subareas include a six-mile buffer around all Areas of Special Biological Significance, a three-mile buffer around all State Oil and Gas Sanctuaries, and all blocks in water deeper than 1000 meters. Deferral of these areas would remove approximately 17 million acres of marine habitat and 460 miles of coastal habitat from the original planning area. The reconfigured planning area would contain approximately 12.9 million acres of marine habitat and 250 miles of coastal habitat. Removal of the marine habitat reduces the score for this component by 0.23 points from that of the original planning area. Removal of the coastal habitat reduces the score for this component by 21.1 points. This reduction results from the removal of most of the moderate-sensitivity rocky beach habitat from the original planning area and the resulting predominance of low-sensitivity sandy beach in the reconfigured planning area. Because the Governor's proposal creates buffers around areas of high coastal bird and marine mammal concentrations, the relative abundances of these biota are reduced from moderate in the original planning area to low in the reconfigured planning area. The score for biota is reduced by 20 points. The net effect of this deferral is a 42-point reduction in the total score for the original planning area. The total score decreases from 219 points for the original planning area to 177 points for the reconfigured planning area (Table I-3.17).

Congressman Regula's Proposal

Congressman Regula proposed the deferral of areas in deep water and in buffer zones adjacent to Areas of Special Biological Significance and State Oil and Gas Sanctuaries. The Congressman also incorporated the Secretary's deferrals into his proposal. Deferral of the areas proposed by the Congressman would remove approximately 16.6 million acres of marine habitat and 296 miles of coastal habitat from the planning area. The reconfigured planning area would contain approximately 13.3 million acres of marine



habitat and 415 miles of coastal habitat. Removal of the marine habitat increases the score for this component by 0.59 points. This increase occurs because the percentage of the area occupied by submerged vegetation in the reconfigured planning area (0.76%) is greater than that occupied in the original planning area (0.43%). Removal of the coastal habitat reduces the score for this component by 5.1 points. This decrease results from a reduction in the percentage of the area occupied by moderate-sensitivity rocky shore habitat in the reconfigured planning area (34.5%) from that present in the original planning area (39.8%). The score for biota remains unchanged. The net effect of this deferral is a 5-point reduction in the total score for the original planning area. The total score decreases from 219 points for the original planning area to 214 points for the reconfigured planning area (Table I-3.18).

Congressman Panetta's Proposal

Congressman Panetta proposed the deferral of a coastal buffer ranging from 3 to 18 miles in width along portions of the shoreline of the Southern California Planning Area. Deferral of this area would remove approximately 1.3 million acres of nearshore marine habitat and 233 miles of coastal habitat from the original planning area. The reconfigured planning area would contain approximately 28.7 million acres of marine habitat and 478 miles of coastal habitat. Removal of the marine habitat reduces the score for this component by 0.2 points. The removal of the coastal habitat increases the score for this component by 10.2 points. This increase results from an increase in the percentage of moderate-sensitivity rocky shore habitat in the reconfigured planning area (51.5%) from that in the original planning area (39.8%). This increase is accompanied by a 11.3% decrease in low-sensitivity sandy beach habitat. The relative abundance of coastal birds is reduced from moderate in the original planning area to low in the reconfigured planning area, producing a 10-point decrease in the score for biota. This deferral produces no change in the total score for the Southern California Planning Area (Table I-3.19).

February 1987 Amalgamated Proposal

Adoption of the Amalgamated Proposal would remove approximately 15.9 million acres of marine habitat and 234 miles of coastal habitat from the original planning area. The reconfigured planning area would contain approximately 14 million acres of marine habitat and 477 miles of coastal habitat. Removal of the coastal habitat would reduce the score for this component by 6.7 points. The percentage of low-sensitivity sandy beach habitat is higher (67.3%), and the percentage of moderate-sensitivity rocky beach habitat is lower (31.9%) in the reconfigured planning area than in the original planning area (59.6% and 39.8%, respectively). Removal of the marine habitat increases the score for this component by 0.75 points because the area occupied by submerged vegetation increases from 0.43% of the original planning area to 0.76% of the reconfigured planning area. Removal of the marine habitat also reduces the relative abundances of coastal birds and marine mammals. This reduces the score for biota by 20 points. The net effect of this deferral is a 26-point reduction in the total score for the original planning area. The total score decreases from

219 points for the original planning area to 193 points for the reconfigured planning area (Table I-3.20a).

The area of the Amalgamated Proposal includes approximately 5.3 million acres of marine habitat and 157 miles of coastal habitat that may be restricted from leasing because of their current military uses. If these military areas are removed from the Amalgamated Proposal, the reconfigured planning area would contain approximately 8.7 million acres of marine habitat and 320 miles of coastal habitat. Removal of the coastal habitat increases the score for this component by 7.9 points because the percentage of low-sensitivity sandy beach is lower (50.6%), and the percentage of moderate-sensitivity rocky beach habitat is higher (66.3%) in the reconfigured planning area than in the original planning area (59.6% and 39.8%, respectively). Removal of the marine habitat produces a 0.98 point increase in the score for this component because the area occupied by submerged vegetation increases from 0.43% of the original planning area to 0.98% of the reconfigured planning area. Removal of the marine habitat reduces the relative abundances of coastal birds and marine mammals. This reduces the score for biota by 20 points. The net effect of this deferral is an 11-point reduction in the total score for the original planning area. The total score decreases from 219 points for the original planning area to 208 points for the reconfigured planning area (Table 20b).

## Cumulative Deferral

The cumulative deferral includes all of the deferrals discussed above for the Southern California Planning Area. Implementation of all the deferrals would remove approximately 19 million acres of marine habitat and 583 miles of coastal habitat from the original planning area. The reconfigured planning area would contain approximately 10.9 million acres of marine habitat and 128 miles of coastal habitat. Removal of the marine habitat reduces the score for this component by 0.45 points. Removal of the coastal habitat reduces the score for this component by 20.7 points. The score for biota decreases by 20 points because of a decrease in the relative abundances of coastal birds and marine mammals in the reconfigured planning area. The net result of this deferral is a 41-point reduction in the total score for the original planning area. The total score decreases from 219 points for the original planning area to 178 points for the reconfigured planning area (Table I-3.21).

## Central California Deferrals

In the Proposed Program, the Central California Planning Area had a total score of 227 points for relative marine productivity and environmental sensitivity. The score was increased to 236 points based on new or revised information. Six deferrals are evaluated for the Central California Planning Area in the following discussions: (1) the Secretary's deferral described in the Proposed Program, (2) the Governor of California's proposed deferral, (3) Congressman Regula's proposed deferral, (4) Congressman Panetta's proposed deferral, (5) the February 1987 Amalgamated Proposal and (6) the cumulative deferral of all these subareas.



## Secretary's Deferrals

The deferrals identified by the Secretary in the Proposed Program include the subarea beyond the area of hydrocarbon potential, the subarea offshore from the Point Reyes Wilderness Area, the subarea off Cordell Bank, the subarea off the Point Reyes-Farallon Islands National Marine Sanctuary, the subarea offshore from San Francisco Bay, the subarea offshore from Monterey Bay, and the subarea offshore from Big Sur. Deferral of these subareas would remove approximately 7.8 million acres of marine habitat and 202 miles of coastal habitat from the original planning area. The reconfigured planning area would contain approximately 7.2 million acres of marine habitat and 109 miles of coastal habitat. Removal of the coastal habitat from the original planning area increases the score for this component in the reconfigured planning area by 13 points because the coastal habitat in the reconfigured planning area has a higher percentage of wetland and rocky-beach habitat (4.6% and 71.6%, respectively) than the original planning area (1.6% and 63.3%, respectively). Removal of the marine habitat produces a 0.38 point reduction in the score for this component. Removal of the subarea around the Farallon Islands reduces the relative abundances of both coastal and marine birds from moderate in the original planning area to low in the reconfigured planning area. This produces a 20-point reduction in the score for biota. The net result of this deferral is a 7-point reduction in the total score for the original planning area. The total score decreases from 236 points for the original planning area to 229 points for the reconfigured planning area (Table I-3.22).

## Governor's Proposal

Deferral of the subarea proposed by the Governor of California would remove approximately 9.2 million acres of marine habitat and all of the coastal habitat from the original planning area. The reconfigured planning area would contain approximately 5.8 million acres of marine habitat and no coastal habitat. Removal of the coastal habitat reduces the score for this component by 104.9 points. Removal of the nearshore marine habitat removes the high-sensitivity submerged vegetaion from the reconfigured planning area. However, the score for marine habitat increases because the percentage of the area occupied by high-sensitivity "coral reef" increases from 0.57% in the original planning area to 1.47% in the reconfigured planning area. This produces a 1.38-point increase in the score for marine habitat. Removal of the coastal habitat reduces the relative abundances of coastal birds and whales in the reconfigured planning area. This reduces the score for biota by 20 points. The net result of this deferral is a 123-point decrease in the total score for the original planning area. The total score decreases from 236 points for the original planning area to 113 points for the reconfigured planning area (Table I-3.23).

## Congressman Regula's Proposal

Congressman Regula's proposal incorporates the Secretary's deferrals made in the Proposed Program plus areas in which water depths exceed 900 meters. Deferral of the area proposed by Congressman Regula would remove approximately 13.3 million acres of marine habitat and all of the coastal habitat from the original planning area. The reconfigured planning area would contain approximately 1.7 million acres of marine habitat and no coastal habitat. Removal of the coastal habitat eliminates all 104.9 points for this ecological component. Removal of the marine habitat reduces the score for this ecological component by 1.27 points. Because the area of the original planning area would be greatly reduced by this proposal, the relative abundances of the biota are generally reduced to low for the reconfigured planning area. This results in a 50-point reduction in the score for the biota component. The net result of this deferral is 156-point reduction in the total score for the original planning area. The total score decreases from 236 points for the original planning area to 80 points for the reconfigured planning area (Table I-3.24).

### Congressman Panetta's Proposal

Congressman Panetta proposed the deferral of a coastal buffer ranging from 3 to 18 miles in width along the entire coast of the Central California Planning Area. Deferral of this area would remove approximately 2.8 million acres of nearshore marine habitat and all coastal habitat from the original planning area. The reconfigured planning area would contain approximately 12.2 million acres of marine habitat and no coastal habitat. Removal of the coastal habitat reduces the score for this ecological component by 104.9 points. Removal of the marine habitat produces a 1.27-point reduction in the score for this ecological component. Provision of the coastal buffer reduces the relative abundances of coastal birds and whales in the reconfigured planning area. This reduces the score for biota by 20 points. The net result of this deferral is a 126-point reduction in the total score for the original planning area. The total score decreases from 236 points for the original planning area to 110 points for the reconfigured planning area (Table I-3.25).

### February 1987 Amalgamated Proposal

Adoption of the Amalgamated Proposal would remove approximately 13 million acres of marine habitat and 298 miles of coastal habitat from the original planning area. The reconfigured planning area would contain approximately 2 million acres of marine habitat and 13 miles of coastal habitat. Removal of the coastal habitat increases the score for this component by 23.2 points. The percentage of low-sensitivity sandy beach habitat is lower (7.7%), and the percentage of moderate-sensitivity rocky beach habitat is higher (92.3%) in the reconfigured planning area than in the original planning area (35.0% and 63.3%, respectively). Removal of the marine habitat reduces the score for this component by 0.16 points. Removal of the marine habitat also reduces the relative abundances of coastal and marine birds and marine mammals. This reduces the score for biota by 30 points. The net effect of this deferral is a 7-point reduction in the total score for the original planning area. The total score decreases from 236 points for the original planning area to 229 points for the reconfigured planning area (Table I-3.26a).

The area of the Amalgamated Proposal includes approximately 353,000 acres of marine habitat that may be restricted from leasing because of their



current military uses. If these military areas are removed from the Amalgamated Proposal, the reconfigured planning area would contain approximately 1.6 million acres of marine habitat and 13 miles of coastal habitat. Because the military areas are relatively small and offshore, their deferral has no effect beyond that discussed for the Amalgamated Proposal with them included. Therefore, the net effect of this deferral is an 7-point reduction in the total score for the original planning area. The total score decreases from 236 points for the original planning area to 229 points for the reconfigured planning area (Table 26b).

### Cumulative Deferral

The cumulative deferral includes all of the deferrals discussed above for the Central California Planning Area. Implementation of the cumulative deferral would remove approximately 14.3 million acres of marine habitat and all coastal habitat from the original planning area. The reconfigured planning area would contain approximately 670,000 acres of marine habitat and no coastal habitat. Removal of the coastal habitat reduces the score for this ecological component by 104.9 points. Removal of the marine habitat produces a 1.27-point reduction in the score for this ecological component. Reduction of the area of the original planning area reduces the relative abundances of all biota, except phytoplankton, to low in the reconfigured planning area. This produces a 50-point reduction in the score for biota. The net result of the cumulative deferral is a 156-point reduction in the total score for the original planning area. The total score decreases from 236 points for the original planning area to 80 points for the reconfigured planning area (Table I-3.27).

## Northern California Deferrals

In the Proposed Program the Northern California Planning Area had a total score of 239 points for relative marine productivity and environmental sensitivity. The score was reduced to 222 points based on new or revised information. Six deferrals for the Northern California Planning Area are evaluated in the following discussions: (1) the Secretary's deferral described in the Proposed Program, (2) the Governor of California's proposed deferral, (3) Congressman Regula's proposed deferral, (4) Congressman Panetta's proposed deferral, (5) the February 1987 Amalgamated Proposal and (6) the cumulative deferral of all these subareas.

### Secretary's Deferral

In the Proposed Program, the Secretary proposed deferring the subarea beyond the area of hydrocarbon potential from the Northern California Planning Area. This deferral would remove approximately 16.7 million acres of deepwater marine habitat from the original planning area. No coastal habitat would be removed from the original planning area as a result of this deferral. The reconfigured planning area would include approximately 11.8 million acres of marine habitat and 245 miles of coastal habitat. The deferral increases the percentage of the area occupied by highly sensitive submerged vegetation in the reconfigured planning area (0.06%) above that in the original planning area (0.02%). However, this increase is not large enough to increase the score significantly for marine habitat or to change the total score for the planning area. The Secretary's proposed deferral has no effect on the total score for the Northern California Planning Area (Table I-3.28).

### Governor's Proposal

Deferral of the subarea proposed by the Governor of California would remove approximately 25 million acres of marine habitat and 130 miles of coastal habitat from the original planning area. The reconfigured planning area would contain approximately 3.5 million acres of marine habitat and 115 miles of coastal habitat. The percentage of the reconfigured planning area occupied by high-sensitivity wetlands is greater than that of the original planning area. This increases the score for the coastal habitat component by two points. The deferral does not have a significant effect on the scores for marine habitat or biota. The net result of this deferral is a 2-point increase in the total score for the original planning area. The total score increases from 222 points for the original planning area to 224 points for the reconfigured planning area (Table I-3.29).

### Congressman Regula's Proposal

Congressman Regula's proposal incorporates the Secretary's deferrals made in the Proposed Program plus areas in which water depths exceed 900 meters. Deferral of these areas would remove approximately 27 million acres of marine habitat and 120 miles of coastal habitat from the original planning area. The reconfigured planning area would include approximately 1.5 million acres of marine habitat and 125 miles of coastal habitat. Removal of the coastal habitat results in a 7.7-point increase in the score for this ecological component because the percentage of rocky coast in the reconfigured planning area (60.8%) is greater than that in the original planning area (44.9%). The deferral has no significant effect on the score for marine habitat. Because the area of the reconfigured planning area is much smaller than the area of the original planning area, the relative abundances of all biota except whales and phytoplankton are rated as low. This results in a 40-point decrease in the score for biota. The net result of this deferral is a 32-point decrease in the total score for the original planning area. The total score decreases from 222 points for the original planning area to 190 points for the reconfigured planning area (Table I-3.30).

### Congressman Panetta's Proposal

Congressman Panetta proposed the deferral of a coastal buffer ranging from 3 to 13 miles in width along the entire coast of the Northern California Planning Area. Deferral of this area would remove approximately 16.7 million acres of nearshore marine habitat and all coastal habitat from the original planning area. The reconfigured planning area would contain approximately 11.8 million acres of marine habitat and no coastal habitat. Removal of the coastal habitat reduces the score for this ecological component by 92.0 points. Removal of the marine habitat has an insignificant



effect on the score for this ecological component. Provision of the coastal buffer reduces the relative abundance of coastal birds and whales in the reconfigured planning area. This reduces the score for biota by 20 points. The net result of this deferral is a 112-point reduction in the total score for the original planning area. The total score decreases from 222 points for the original planning area to 110 points for the reconfigured planning area (Table I-3.31).

### February 1987 Amalgamated Proposal

Adoption of the Amalgamated Proposal would remove approximately 25.6 million acres of marine habitat and 150 miles of coastal habitat from the original planning area. The reconfigured planning area would contain approximately 2.9 million acres of marine habitat and 95 miles of coastal habitat. Removal of the coastal habitat increases the score for this component by 5.9 points. The percentage of low-sensitivity sandy beach habitat is lower (43.2%), and the percentage of moderate-sensitivity rocky beach habitat is higher (54.7%) in the reconfigured planning area than in the original planning area (51.4% and 44.9%, respectively). Removal of the marine habitat increases the score for this component by 0.13 points because the area occupied by submerged vegetation increases from 0.02% of the original planning area to 0.09% of the reconfigured planning area. Removal of the marine habitat also reduces the relative abundances of juvenile fish and shellfish and marine birds. This reduces the score for biota by 20 points. The net effect of this deferral is a 14-point reduction in the total score for the original planning area. The total score decreases from 222 points for the original planning area to 208 points for the reconfigured planning area (Table I-3.32).

### Cumulative Deferral

The cumulative deferral includes all of the deferrals discussed above for the Northern California Planning Area. Implementation of the cumulative deferral would remove approximately 27.8 million acres of marine habitat and all coastal habitat from the original planning area. The reconfigured planning area would contain approximately 690,000 acres of marine habitat and no coastal habitat. Removal of the coastal habitat reduces the score for this ecological component by 92.0 points. Removal of the marine habitat has an insignificant effect on the score for this ecological component. Reduction of the area of the original planning area reduces the relative abundance of all biota, except phytoplankton, to low. This produces a 50-point reduction in the score for biota. The net result of the cumulative deferral is a 142-point reduction in the total score for the original planning area. The total score decreases from 222 points for the original planning area to 80 points for the reconfigured planning area (Table I-3.33).

### Washington/Oregon Deferrals

In the Proposed Program, the Washington/Oregon Planning Area had a total score of 256 points for relative marine productivity and environmental sensitivity. Four deferrals for the Oregon/Washington Planning Area are evaluated in the following discussions: (1) the Secretary's deferral, (2) the Governor of Washington's proposed deferrals, (3) the Governor of Oregon's proposed deferrals, and (4) the cumulative deferral of all these subareas.

### Secretary's Deferral

In the Proposed Program, the Secretary proposed the deferral of the subarea beyond the area of hydrocarbon potential. Deferral of this subarea would remove approximately 21.7 million acres of deepwater marine habitat from the planning area. The reconfigured planning area would contain approximately 26.2 million acres of marine habitat and 453 miles of coastal habitat. The deferral has no effect on the scores for coastal habitat or biota. Because of the low sensitivity of the marine habitat removed from the original planning area, the deferral has no effect on the total score for the planning area (Table I-3.34).

### Governor's (Washington) Proposal

The Governor of Washington proposed deferring the subarea north of the 47° N. latitude; a 12-mile buffer around Grays Harbor, Willapa Bay, and the Columbia River Estuary; and deepwater areas offshore Washington. In this evaluation, deepwater areas are assumed to be the same as the Secretary's proposal. Deferral of the areas proposed by the Governor would remove approximately 13.8 million acres of marine habitat and 157 miles of coastal habitat from the original planning area. The reconfigured planning area would contain approximately 34 million acres of marine habitat, mostly offshore Oregon, and 296 miles of coastal habitat. The coastal and marine habitats in the reconfigured planning area are generally similar to those in the original planning area. As a result, the deferral has no effect on the scores for coastal or marine habitat. The deferral has no effect on the score for biota. The Governor's proposal does not change the total score for the original planning area (Table I-3.35).

### Governor's (Oregon) Proposal

The Governor of Oregon proposed deferring the following areas from the Washington/Oregon Planning Area: areas offshore Oregon in water deeper than 200 meters: a 6-mile buffer around Cascade Head, the Salmon and Columbia River estuaries, Yaquina and Coos Bays, the Oregon Islands National Wildlife Refuges, and the area around Stonewall, Perpetua, Hecata, and Coquille Banks. Deferral of the areas proposed by the Governor would remove approximately 30.5 million acres of marine habitat and 184 miles of coastal habitat from the original planning area. The reconfigured planning area would contain approximately 17.4 million acres of marine habitat and 269 miles of coastal habitat. The coastal and marine habitats in the reconfigured planning area are generally similar to those in the original planning area. As a result, the deferral has no effect on the scores for coastal or marine habitat. The deferral has no effect on the score for biota. The Governor's proposal does not change the total score for the original planning area (Table I-3.36).



### Cumulative Deferral

The cumulative deferral includes the three deferrals discussed above for the Washington/Oregon Planning Area. Implementation of the cumulative deferral would remove approximately 44.3 million acres of marine habitat and 341 miles of coastal habitat from the original planning area. The reconfigured planning area would contain approximately 3.6 million acres of marine habitat and 112 miles of coastal habitat. Removal of the marine and coastal habitat has no effect on the score for these components. However, the reduction in the size of the planning area reduces the relative abundances of juvenile fish and shellfish, marine and coastal birds, and marine mammals from moderate in the original planning area to low in the reconfigured planning area. This reduces the score for biota by 40 points. The net result of the cumulative deferral is a 40-point reduction in the total score for the original planning area. The total score decreases from 256 points for the original planning area to 216 points for the reconfigured planning area (Table I-3.37).

## Alaska Region Deferrals

Subarea deferrals are proposed for five planning areas in the Alaska Region: St. George Basin, North Aleutian Basin, Navarin Basin, Norton Basin, and the Beaufort Sea.

## St. George Basin Deferrals

In the Proposed Program, the St. George Basin Planning Area had a total score of 281 points for relative marine productivity and environmental sensitivity. The score was increased to 287 points based on new or revised information. Two deferrals from the St. George Basin Planning Area are evaluated in the following discussions: (1) the Unimak Pass deferral and (2) the Institute for Resource Management (IRM) Proposal.

### Unimak Pass Deferral

In the Proposed Program, the Secretary highlighted for further study the deferral of the subarea of the St. George Basin adjacent to the Unimak Pass. Deferral of this subarea would remove of approximately 864,000 acres of nearshore marine habitat and 39 miles of coastal habitat from the original planning area. The reconfigured planning area would contain approximately 69.3 million acres of marine habitat and the coastal habitat remaining from the original planning area. The coastal and marine habitats remaining in the reconfigured planning area have the same general composition as those in the original planning area. As a result, the deferral has no effect on the scores for these components. The provision of a buffer around the migratory corridor at the Unimak Pass reduces the abundance of marine mammals and whales in the reconfigured planning area. This produces a 20-point reduction in the score for biota. The net effect of the Unimak Pass deferral is a 20-point reduction in the total score for the original planning area. The total score decreases from 287 points for the original planning area to 267 points for the reconfigured planning area (Table I-3.38)

## Institute for Resource Management Proposal

Implementation of the IRM proposal would remove approximately 46.5 million acres of marine habitat and all coastal habitat from the original planning area. The reconfigured planning area would contain approximately 23.7 million acres of marine habitat and no coastal habitat. Removal of the coastal habitat reduces the score for this ecological component by 104 points. Removal of the marine habitat has no effect on the score for this ecological component. Because this proposal would provide a substantial buffer around coastal areas and would substantially reduce the size of the original planning area, the abundances of coastal and marine birds, marine mammals, and whales in the reconfigured planning area are assumed to be lower than those in the original planning area. This assumption produces a 40-point reduction in the score for biota. Implementation of the IRM proposal would reduce the total score for the original planning area by 144 points. The total score decreases from 287 points for the original planning area to 143 points for the reconfigured planning area (Table I-3.39). Because the IRM proposal includes the Unimak Pass deferral, the overall total score for the IRM proposal is the cumulative score for both deferrals considered for the St. George Basin.

## North Aleutian Basin Deferral

In the Proposed Program, the North Aleutian Basin Planning Area had a total score of 327 points for relative marine productivity and environmental sensitivity. The score was reduced to 326 points based on new or revised information.

The Secretary highlighted for further study the subarea of the North Aleutian Basin adjacent to the Unimak Pass in the Proposed Program. Deferral of this subarea would result in the removal of approximately 350,000 acres of marine habitat and 50 miles of coastal habitat from the original planning area. The reconfigured planning area would contain approximately 32.1 million acres of marine habitat and the remaining coastal habitat from the original planning area. The coastal and marine habitats in the reconfigured planning area have the same general composition as those in the original planning area. As a result, the Unimak Pass deferral has no effect on the total score for the North Aleutian Basin Planning Area (Table I-3.40).

## Navarin Basin Deferral

In the Proposed Program, the Navarin Basin Planning Area had a total score of 131 points for relative marine productivity and environmental sensitivity. The score was increased to 141 points based on new or revised information.

The only deferral evaluated for the Navarin Basin Planning Area is the Institute for Resource Management (IRM) proposal. Implementation of this proposal would remove approximately 15.3 million acres of marine habitat from the planning area. The planning area has no coastal habitat. The



reconfigured planning area would contain approximately 21.8 million acres of marine habitat. Removal of the marine habitat has no effect on the score for this component. The proposal has no effect on the score for biota. As a result, implementation of the IRM proposal has no effect on the total score for the Navarin Basin Planning Area (Table I-3.41).

## Norton Basin Deferrals

In the Proposed Program, the Norton Basin Planning Area had a total score of 280 points for relative marine productivity and environmental sensitivity. The score was reduced to 264 points based on new or revised information. Two deferrals from the Norton Basin Planning Area are evaluated in the following discussions: (1) the Yukon Delta Coastal Buffer and (2) the Institute for Resource Management Proposal.

### Yukon Delta Coastal Buffer

Deferral of a 12-mile buffer around the Yukon River delta would remove approximately 455,000 acres of nearshore marine habitat and 79 miles of coastal habitat from the planning area. The reconfigured planning area would contain approximately 24.5 million acres of marine habitat and 1785 miles of coastal habitat. Because of the generally high turbidity of the Yukon River discharge, the marine habitat removed as part of this deferral is assumed to contain little submerged vegetation. As a result, the deferral has little effect on the score for the marine habitat component. The coastal area removed is principally estuarine and wetland habitat. The removal of this high-sensitivity habitat reduces the score for this component by 5 points. The deferral has no effect on the score for biota. The net effect of this deferral is a 5-point reduction in the total score for the original planning area. The total score decreases from 264 points for the original planning area to 259 points for the reconfigured planning area (Table I.3-42).

### Institute for Resource Management Proposal

Implementation of the Institute for Resource Management (IRM) proposal would remove approximately 21.5 million acres and all of the coastal habitat from the planning area. The reconfigured planning area would contain approximately 3.5 million acres of marine habitat and no coastal habitat. Removal of the coastal habitat reduces the score for this component by 105-points. Removal of the marine habitat has no effect on the score for this component. Because the reconfigured planning area would provide a substantial buffer around all coastal areas, the relative abundance of coastal birds in the area is assumed to be low rather than high as it was in the original planning area. This change produces a 20-point reduction in the score for biota. Implementation of this proposal would reduce the total score for the original planning area by 125 points. The total score decreases from 264 points for the original planning area to 137 points for the reconfigured planning area (Table I-3.43). Because the IRM proposal includes the Yukon River Delta Buffer, the total score for this deferral is the cumulative score for both deferrals considered for the Norton Basin Planning Area.

Beaufort Sea Deferral

In the Proposed Program, the Beaufort Sea Planning Area had a total score of 261 points for relative marine productivity and environmental sensitivity. This score was reduced to 257 points based on new or revised information.

In the Proposed Program, The Secretary highlighted for further study the deferral of 59 blocks in the Beaufort Sea offshore from Point Barrow. Deferring this area would remove approximately 330,000 acres of nearshore marine habitat and approximately 29 miles of coastal habitat from the planning area. The reconfigured planning area would contain approximately 49.1 million acres of marine habitat and the coastal habitat remaining from the original planning area. Removal of the marine habitat would have no significant effect on the score for this component. The coastal habitat in the reconfigured planning area has a composition similar to that of the original planning area. As a result, the removal of this segment of the coast has no effect on the score for this ecological component. Because of its relatively small size and the wide distribution of sensitive species in the planning area, the deferral would have no effect on the score for biota. The deferral would have no effect on the total score for the relative environmental sensitivity of the original Beaufort Sea Planning Area (Table I-3.44).

## IV. Discussion

Subarea deferrals were evaluated for 15 of the 22 OCS planning areas analyzed for their relative marine productivity and environmental sensitivity in Appendix I. The total scores for relative marine productivity and environmental sensitivity in 10 of the 15 planning areas were reduced by the cumulative or other deferrals. The total scores for 4 planning areas were unchanged by proposed deferrals, and the score for one planning area (Straits of Florida) increased as the result of a subarea deferral. The planning areas which experienced the greatest reduction in their total scores for relative marine productivity and environmental sensitivity are as follows: Central California (156 points), St. George Basin (144 points), Northern California (142 points), Norton Basin (125 points), and North Atlantic (111 points).

Deferrals involving the removal of substantial lengths of coastal habitat generally produced the greatest reductions in total scores. This effect is illustrated in the Atlantic and California planning areas, the Eastern Gulf of Mexico, and Norton Basin. Removal of short segments of coastal habitat generally had little effect on a planning area's total score (North Aleutian Basin and Beaufort Sea). In the Straits of Florida, the deferral of low-sensitivity coastal habitat from the original planning area concentrated high-sensitivity habitat in the reconfigured planning area and increased the score for this component. Similar increases for the same reason occurred for subarea deferrals in the North Atlantic, Eastern Gulf of Mexico, and the three California planning areas.



The concentration of moderate- or high-sensitivity resources in reconfigured planning areas by subarea deferrals was not limited to coastal habitat. The same effect occurred in the marine habitat component. In these instances, identifiable nearshore resources were generally left in a reconfigured planning area after large areas of deepwater habitat were deferred from the original planning area. This effectively increased the percentage of the remaining marine habitat occupied by moderate- or high-sensitivity resources and increased the score for the marine habitat component. This effect occurred in the South Atlantic, Straits of Florida, the California planning areas, and the Norton Basin.

Many deferrals affected the relative abundance of biota in the reconfigured planning areas. Some deferrals eliminated habitats in which specific biota were generally concentrated (fish and shellfish-Georges Bank [North Atlantic]; gray whales-nearshore zone [California]). Other deferrals eliminated enough of the original planning area that the remaining reconfigured planning area was too small to support substantial populations (California planning areas).

The ranks and total scores of the original 22 OCS planning areas and the reconfigured planning areas following the cumulative deferral of subareas are compared in Table I-3.45. As a result of the deferrals, seven planning areas (St. George Basin, Norton Basin, Central California, South Atlantic, Northern California, Washington/Oregon and North Atlantic) dropped in their relative ranks among the 22 planning areas. The ranks of two planning areas (Hope Basin and North Aleutian Basin) were unaffected by the deferrals. The ranks of the remaining 13 planning areas increased.

The most immediate effect of the deferrals is the elimination of the St. George Basin and the Norton Basin from the ten most most sensitive planning areas. The seven next-most sensitive planning areas (ranks 3 through 9 in Appendix I) move up to occupy the ranks vacated by the St. George Basin and Norton Basin planning areas. For the cumulative deferral, the six most sensitive planning areas are in the Alaska Region. Without deferrals (Appendix I), the seven most sensitive planning areas are in the Alaska Region. The Washington/Oregon and Central Gulf of Mexico planning areas remain in the ten most sensitive planning areas and are joined by the Straits of Florida in the cumulative deferral list.

TABLE I-45.

Relative Marine Productivity and Environmental Sensitivity

Comparison of the Ranks of Entire Planning Areas and Reconfigured Planning Areas Following the Cumulative Deferral of Subareas

| | Entire Planning Area | | Reconfigured Planning Area | |
|---|---|---|---|---|
| Rank | Planning Area | Total Score | Planning Area | Total Score |
| 1 | Hope Basin | 349 | Hope Basin | 349 |
| 2 | North Aleutian Basin | 327 | North Aleutian Basin | 326 |
| 3 | St. George Basin | 281 | Cook Inlet | 272 |
| 4 | Norton Basin | 280 | Shumagin | 265 |
| 5 | Cook Inlet | 272 | Kodiak | 264 |
| 6 | Shumagin | 265 | Beaufort Sea | 255 |
| 7 | Kodiak | 264 | Central Gulf of Mexico | 254 |
| 8 | Beaufort Sea | 261 | Straits of Florida | 243 |
| 9 | Washington/Oregon | 256 | Gulf of Alaska | 235 |
| 10 | Central Gulf of Mexico | 254 | Washington/Oregon | 216 |
| 11 | Central California | 236 | Chukchi Sea | 204 |
| 12 | Gulf of Alaska | 235 | Western Gulf of Mexico | 180 |
| 13 | Straits of Florida | 234 | Eastern Gulf of Mexico | 173 |
| 14 | South Atlantic | 230 | St. George Basin | 153 |
| 15 | Northern California | 222 | Navarin Basin | 141 |
| 16 | Southern California | 214 | Norton Basin | 137 |
| 17 | North Atlantic | 209 | South Atlantic | 124 |
| 18 | Eastern Gulf of Mexico | 208 | Mid-Atlantic | 118 |
| 19 | Chukchi Sea | 204 | Southern California | 116 |
| 20 | Mid-Atlantic | 198 | North Atlantic | 98 |
| 21 | Western Gulf of Mexico | 180 | Central California | 80 |
| 22 | Navarin Basin | 141 | Northern California | 80 |

# APPENDIX I-3

# RELATIVE MARINE PRODUCTIVITY AND ENVIRONMENTAL SENSITIVITY

# OIL SPILLS

# EFFECTS OF SUBAREA DEFERRALS

# CALCULATIONS

Proposed Final Program:
5-Year Outer Continental Shelf Oil and Gas Leasing Program
for Mid-1987 through Mid-1991

TABLE I-3.1

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: North Atlantic
15-Nautical Mile Deferral

Total Score: 116

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | Negligible | 0.0 | High | 225 | 0.0 |
| Sandy Beaches | Negligible | 0.0 | Low | 45 | 0.0 |
| Rocky Beaches | Negligible | 0.0 | Moderate | 135 | 0.0 |
| TOTAL | | | | | 0.0 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | Negligible | 0.00 | High | 225 | 0.00 |
| Submarine Canyons | 1,290,000 | 2.82 | Low | 45 | 1.27 |
| Coral Reefs | Negligible | 0.0 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | 6,496,000 | 14.2 | Low | 45 | 6.39 |
| Mud/Sand Bottom | 37,914,000 | 83.0 | Low | 45 | 37.33 |
| TOTAL | 45,700,000 | | | | 44.99 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | High | 5 | High | 5 | 25 |
| Adult Fish/Shellfish | High | 5 | Moderate | 3 | 15 |
| Mud/Sand Benthos | Moderate | 3 | Low | 1 | 3 |
| Coastal Birds | Low | 1 | High | 5 | 5 |
| Marine Birds | Low | 1 | High | 5 | 5 |
| Marine Turtles | Low | 1 | Moderate | 3 | 3 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 71 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.2

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: North Atlantic
Gulf of Maine Deferral

Total Score: 184

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 14 | 7.4 | High | 225 | 16.7 |
| Sandy Beaches | 179 | 92.6 | Low | 45 | 41.7 |
| Rocky Beaches | Negligible | 0.0 | Moderate | 135 | 0.0 |
| TOTAL | 193 | | | | 58.4 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | Negligible | 0.00 | High | 225 | 0.00 |
| Submarine Canyons | 1,290,000 | 3.20 | Low | 45 | 1.44 |
| Coral Reefs | Negligible | 0.0 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | 6,496,000 | 16.1 | Low | 45 | 7.25 |
| Mud/Sand Bottom | 32,514,000 | 80.7 | Low | 45 | 36.31 |
| TOTAL | 40,300,000 | | | | 45.00 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | High | 5 | High | 5 | 25 |
| Adult Fish/Shellfish | High | 5 | Moderate | 3 | 15 |
| Mud/Sand Benthos | Moderate | 3 | Low | 1 | 3 |
| Coastal Birds | Moderate | 3 | High | 5 | 15 |
| Marine Birds | Low | 1 | High | 5 | 5 |
| Marine Turtles | Low | 1 | Moderate | 3 | 3 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 81 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.3

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: North Atlantic
Congressional Deferral

Total Score: 202

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 25 | 7.6 | High | 225 | 17.1 |
| Sandy Beaches | 176 | 52.9 | Low | 45 | 23.8 |
| Rocky Beaches | 132 | 39.5 | Moderate | 135 | 53.3 |
| TOTAL | 333 | | | | 94.2 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | Negligible | 0.0 | High | 225 | 0.00 |
| Submarine Canyons | Negligible | 0.0 | Low | 45 | 0.00 |
| Coral Reefs | Negligible | 0.0 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | 6,496,000 | 17.2 | Low | 45 | 7.73 |
| Mud/Sand Bottom | 31,304,000 | 82.8 | Low | 45 | 37.26 |
| TOTAL | 37,800,000 | | | | 44.99 |
| Biota | | | | | |
| Phytoplankton | Moderate | 3 | Low | 1 | 3 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Moderate | 3 | Moderate | 3 | 9 |
| Mud/Sand Benthos | Moderate | 3 | Low | 1 | 3 |
| Coastal Birds | Moderate | 3 | High | 5 | 15 |
| Marine Birds | Low | 1 | High | 5 | 5 |
| Marine Turtles | Low | 1 | Moderate | 3 | 3 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 63 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.4

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: North Atlantic
Cumulative Deferral

Total Score: 98

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | Negligible | 0.0 | High | 225 | 0.0 |
| Sandy Beaches | Negligible | 0.0 | Low | 45 | 0.0 |
| Rocky Beaches | Negligible | 0.0 | Moderate | 135 | 0.0 |
| TOTAL | | | | | 0.0 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | Negligible | 0.0 | High | 225 | 0.00 |
| Submarine Canyons | Negligible | 0.0 | Low | 45 | 0.00 |
| Coral Reefs | Negligible | 0.0 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | 6,496,000 | 24.9 | Low | 45 | 11.20 |
| Mud/Sand Bottom | 19,604,000 | 75.1 | Low | 45 | 33.80 |
| TOTAL | 28,400,000 | | | | 45.00 |
| Biota | | | | | |
| Phytoplankton | Moderate | 3 | Low | 1 | 3 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Moderate | 3 | Moderate | 3 | 9 |
| Mud/Sand Benthos | Moderate | 3 | Low | 1 | 3 |
| Coastal Birds | Low | 1 | High | 5 | 5 |
| Marine Birds | Low | 1 | High | 5 | 5 |
| Marine Turtles | Low | 1 | Moderate | 3 | 3 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 53 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

## TABLE I-3.5

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Mid-Atlantic
U.S.S. Monitor and 15-Nautical Mile Deferral

Total Score: 118

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | Negligible | 0.0 | High | 225 | 0.0 |
| Sandy Beaches | Negligible | 0.0 | Low | 45 | 0.0 |
| Rocky Beaches | Negligible | 0.0 | Moderate | 135 | 0.0 |
| TOTAL | | | | | 0.0 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | Negligible | 0.00 | High | 225 | 0.00 |
| Submarine Canyons | 600,000 | 0.80 | Low | 45 | 0.36 |
| Coral Reefs | Negligible | 0.0 | High | 225 | 0.00 |
| Hard Bottoms | Negligible | 0.0 | Low | 45 | 0.00 |
| Shelf Break Zone | 581,000 | 0.77 | Low | 45 | 0.35 |
| Mud/Sand Bottom | 74,219,000 | 98.4 | Low | 45 | 44.29 |
| TOTAL | 75,400,000 | | | | 45.00 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | High | 5 | High | 5 | 25 |
| Adult Fish/Shellfish | Moderate | 3 | Moderate | 3 | 9 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Low | 3 | High | 5 | 5 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | Moderate | 3 | Low | 1 | 3 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 73 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

## TABLE I-3.6

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: South Atlantic
15-Nautical Mile Deferral

Total Score: 125

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | Negligible | 0.0 | Moderate | 135 | 0.0 |
| Sandy Beaches | Negligible | 0.0 | Low | 45 | 0.0 |
| Rocky Beaches | Negligible | 0.0 | Low | 45 | 0.0 |
| TOTAL | | | | | 0.0 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | Negligible | 0.0 | High | 225 | 0.00 |
| Submarine Canyons | 75,000 | 0.08 | Low | 45 | 0.04 |
| Coral Reefs | 481,000 | 0.49 | High | 225 | 1.19 |
| Hard Bottoms | 1,689,000 | 1.73 | Low | 45 | 0.78 |
| Shelf Break Zone | 3,826,000 | 3.91 | Low | 45 | 1.76 |
| Mud/Sand Bottom | 91,729,000 | 93.8 | Low | 45 | 42.21 |
| TOTAL | 97,800,000 | | | | 45.98 |
| Biota | | | | | |
| Phytoplankton | Moderate | 3 | Low | 1 | 3 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | High | 5 | Moderate | 3 | 15 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Low | 1 | High | 5 | 5 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | High | 5 | Moderate | 3 | 15 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 79 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.7

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: South Atlantic
NASA Deferral

Total Score: 229

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 250 | 44.1 | Moderate | 135 | 59.5 |
| Sandy Beaches | 317 | 55.9 | Low | 45 | 25.2 |
| Rocky Beaches | Negligible | 0.0 | Low | 45 | 0.0 |
| TOTAL | 567 | | | | 84.7 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 16,500 | 0.02 | High | 225 | 0.05 |
| Submarine Canyons | 75,000 | 0.08 | Low | 45 | 0.04 |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | 1,655,000 | 1.91 | Low | 45 | 0.86 |
| Shelf Break Zone | 3,750,000 | 4.32 | Low | 45 | 1.94 |
| Mud/Sand Bottom | 81,303,500 | 93.7 | Low | 45 | 42.17 |
| TOTAL | 86,800,000 | | | | 45.06 |
| Biota | | | | | |
| Phytoplankton | Moderate | 3 | Low | 1 | 3 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | High | 5 | Moderate | 3 | 15 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | High | 5 | High | 5 | 25 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | High | 5 | Moderate | 3 | 15 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 99 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.8

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: South Atlantic
Cumulative Deferral

Total Score: 124

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | Negligible | 0.0 | Moderate | 135 | 0.0 |
| Sandy Beaches | Negligible | 0.0 | Low | 45 | 0.0 |
| Rocky Beaches | Negligible | 0.0 | Low | 45 | 0.0 |
| TOTAL | | | | | 0.0 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | Negligible | 0.0 | High | 225 | 0.00 |
| Submarine Canyons | 75,000 | 0.11 | Low | 45 | 0.05 |
| Coral Reefs | Negligible | 0.0 | High | 225 | 0.00 |
| Hard Bottoms | 1,655,000 | 2.12 | Low | 45 | 0.95 |
| Shelf Break Zone | 3,750,000 | 4.81 | Low | 45 | 2.16 |
| Mud/Sand Bottom | 72,520,000 | 93.0 | Low | 45 | 41.85 |
| TOTAL | 78,000,000 | | | | 45.01 |
| Biota | | | | | |
| Phytoplankton | Moderate | 3 | Low | 1 | 3 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | High | 5 | Moderate | 3 | 15 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Low | 1 | High | 5 | 5 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | High | 5 | Moderate | 3 | 15 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 79 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.9

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Straits of Florida
Atlantic Coast Deferral

Total Score: 246

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 100 | 67 | Moderate | 135 | 90.5 |
| Sandy Beaches | 50 | 33 | Low | 45 | 14.9 |
| Rocky Beaches | Negligible | 0.0 | Low | 45 | 0.0 |
| TOTAL | 150 | | | | 105.4 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 61,400 | 1.31 | High | 225 | 2.95 |
| Submarine Canyons | Negligible | 0.00 | Low | 45 | 0.00 |
| Coral Reefs | 271,000 | 5.77 | High | 225 | 12.98 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 41.81 |
| TOTAL | 4,700,000 | | | | 57.74 |
| Biota | | | | | |
| Phytoplankton | Moderate | 3 | Low | 1 | 3 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Moderate | 3 | Moderate | 3 | 9 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Moderate | 3 | High | 5 | 15 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | High | 5 | Moderate | 3 | 15 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 83 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.10

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Eastern Gulf of Mexico
Seagrass Beds and Florida Middle Ground Deferral

Total Score: 189

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 222 | 43.5 | Moderate | 135 | 58.7 |
| Sandy Beaches | 288 | 56.5 | Low | 45 | 25.4 |
| Rocky Beaches | Negligible | 0.0 | Low | 45 | 0.0 |
| TOTAL | 586 | | | | 84.1 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 1,200,000 | 1.69 | High | 225 | 3.80 |
| Submarine Canyons | Negligible | 0.00 | Low | 45 | 0.00 |
| Coral Reefs | 100,000 | 0.14 | High | 225 | 0.32 |
| Hard Bottoms | 10,874,000 | 15.3 | Low | 45 | 6.89 |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | 78.6 | Low | 45 | 37.28 |
| TOTAL | 71,000,000 | | | | 48.29 |
| Biota | | | | | |
| Phytoplankton | Low | 1 | Low | 1 | 1 |
| Juvenile Fish/Shellfish | Low | 1 | High | 5 | 5 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Moderate | 3 | Low | 1 | 3 |
| Coastal Birds | Moderate | 3 | High | 5 | 15 |
| Marine Birds | Low | 1 | High | 5 | 5 |
| Marine Turtles | High | 5 | Moderate | 3 | 15 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 57 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Table I-3.11

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Eastern Gulf of Mexico — 30-Nautical Mile Coastal Buffer — Total Score: 137

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | Negligible | 0.0 | Moderate | 135 | 0.0 |
| Sandy Beaches | 137 | 100 | Low | 45 | 45.0 |
| Rocky Beaches | Negligible | 0.0 | Low | 45 | 0.0 |
| TOTAL | 137 | | | | 45.0 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | Negligible | 0.00 | High | 225 | 0.00 |
| Submarine Canyons | Negligible | 0.00 | Low | 45 | 0.00 |
| Coral Reefs | 133,000 | 0.24 | High | 225 | 0.54 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 44.89 |
| TOTAL | 55,000,000 | | | | 45.43 |
| Biota | | | | | |
| Phytoplankton | Low | 1 | Low | 1 | 1 |
| Juvenile Fish/Shellfish | Low | 1 | High | 5 | 5 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Moderate | 3 | Low | 1 | 3 |
| Coastal Birds | Low | 1 | High | 5 | 5 |
| Marine Birds | Low | 1 | High | 5 | 5 |
| Marine Turtles | High | 5 | Moderate | 3 | 15 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 47 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Table I-3.12

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Eastern Gulf of Mexico — Apalachicola to Panama City Deferral — Total Score: 202

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 343 | 55.1 | Moderate | 135 | 74.4 |
| Sandy Beaches | 279 | 44.9 | Low | 45 | 20.2 |
| Rocky Beaches | Negligible | 0.0 | Low | 45 | 0.0 |
| TOTAL | 622 | | | | 94.6 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 2,026,000 | 2.84 | High | 225 | 6.39 |
| Submarine Canyons | Negligible | 0.00 | Low | 45 | 0.00 |
| Coral Reefs | 232,500 | 0.33 | High | 225 | 0.73 |
| Hard Bottoms | 10,874,000 | 15.3 | Low | 45 | 6.86 |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 36.69 |
| TOTAL | 71,300,000 | | | | 50.67 |
| Biota | | | | | |
| Phytoplankton | Low | 1 | Low | 1 | 1 |
| Juvenile Fish/Shellfish | Low | 1 | High | 5 | 5 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Moderate | 3 | Low | 1 | 3 |
| Coastal Birds | Moderate | 3 | High | 5 | 15 |
| Marine Birds | Low | 1 | High | 5 | 5 |
| Marine Turtles | High | 5 | Moderate | 3 | 15 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 57 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.13

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Eastern Gulf of Mexico
Miami Protraction Diagram Deferral

Total Score: 186

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 193 | 36.9 | Moderate | 135 | 49.8 |
| Sandy Beaches | 330 | 63.1 | Low | 45 | 28.4 |
| Rocky Beaches | Negligible | 0.0 | Low | 45 | 0.0 |
| TOTAL | 523 | | | | 78.2 |

| | (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|---|
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 1,967,000 | 2.77 | High | 225 | 6.24 |
| Submarine Canyons | Negligible | 00.0 | Low | 45 | 0.00 |
| Coral Reefs | 226,000 | 0.32 | High | 225 | 0.72 |
| Hard Bottoms | 10,558,400 | 14.9 | Low | 45 | 6.70 |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 36.91 |
| TOTAL | 70,900,000 | | | | 50.57 |

| | (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|---|
| Biota | | | | | |
| Phytoplankton | Low | 1 | Low | 1 | 1 |
| Juvenile Fish/Shellfish | Low | 1 | High | 5 | 5 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Moderate | 3 | Low | 1 | 3 |
| Coastal Birds | Moderate | 3 | High | 5 | 15 |
| Marine Birds | Low | 1 | High | 5 | 5 |
| Marine Turtles | High | 5 | Moderate | 3 | 15 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 57 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.14

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Eastern Gulf of Mexico
Cumulative Deferral

Total Score: 137

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | Negligible | 0.0 | Moderate | 135 | 0.0 |
| Sandy Beaches | 93 | 100 | Low | 45 | 45.0 |
| Rocky Beaches | Negligible | 0.0 | Low | 45 | 0.0 |
| TOTAL | 93 | | | | 45.0 |

| | (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|---|
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | Negligible | 0.0 | High | 225 | 0.00 |
| Submarine Canyons | Negligible | 0.0 | Low | 45 | 0.00 |
| Coral Reefs | Negligible | 0.0 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 45.00 |
| TOTAL | 51,600,000 | | | | 45.00 |

| | (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|---|
| Biota | | | | | |
| Phytoplankton | Low | 1 | Low | 1 | 1 |
| Juvenile Fish/Shellfish | Low | 1 | High | 5 | 5 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Moderate | 3 | Low | 1 | 3 |
| Coastal Birds | Low | 3 | High | 5 | 5 |
| Marine Birds | Low | 1 | High | 5 | 5 |
| Marine Turtles | High | 5 | Moderate | 3 | 15 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 47 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.15

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Western Gulf of Mexico
Flower Garden Bank Deferral

Total Score: 180

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 56 | 10.2 | Moderate | 135 | 13.8 |
| Sandy Beaches | 489 | 89.8 | Low | 45 | 40.4 |
| Rocky Beaches | Negligible | 0.0 | Low | 45 | 0.0 |
| TOTAL | 545 | | | | 54.2 |

| | | | | | |
|---|---|---|---|---|---|
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | Negligible | 0.00 | High | 225 | 0.0 |
| Submarine Canyons | Negligible | 0.00 | Low | 45 | 0.0 |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.0 |
| Hard Bottoms | 52,000 | 0.15 | Low | 45 | 0.07 |
| Shelf Break Zone | 1,607,000 | 4.55 | Low | 45 | 2.05 |
| Mud/Sand Bottom | 33,636,000 | 95.3 | Low | 45 | 42.89 |
| TOTAL | 35,295,000 | | | | 45.06 |

| | | | | | |
|---|---|---|---|---|---|
| Biota | | | | | |
| Phytoplankton | Low | 1 | Low | 1 | 1 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Moderate | 3 | Moderate | 3 | 9 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | High | 5 | High | 5 | 25 |
| Marine Birds | Low | 1 | High | 5 | 5 |
| Marine Turtles | High | 5 | Moderate | 3 | 15 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 81 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.16

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Southern California
Secretary's Deferrals

Total Score: 211

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 3 | 0.7 | High | 225 | 1.7 |
| Sandy Beaches | 293 | 69.2 | Low | 45 | 31.1 |
| Rocky Beaches | 127 | 30.1 | Moderate | 135 | 40.6 |
| TOTAL | 423 | | | | 73.4 |

| | | | | | |
|---|---|---|---|---|---|
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 120,000 | 0.75 | High | 225 | 1.68 |
| Submarine Canyons | | | Low | 45 | |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 44.66 |
| TOTAL | 16,000,000 | | | | 46.34 |

| | | | | | |
|---|---|---|---|---|---|
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Moderate | 3 | Moderate | 3 | 9 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Moderate | 3 | High | 5 | 15 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | Low | 1 | Low | 1 | 1 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 91 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.17

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Southern California
Governor's Proposal

Total Score: 177

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 2 | 0.8 | High | 225 | 1.8 |
| Sandy Beaches | 209 | 84.0 | Low | 45 | 37.5 |
| Rocky Beaches | 40 | 16.0 | Moderate | 135 | 21.5 |
| TOTAL | 251 | | | | 60.8 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 38,000 | 0.30 | High | 225 | 0.68 |
| Submarine Canyons | | | Low | 45 | |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 44.87 |
| TOTAL | 12,900,000 | | | | 45.55 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Moderate | 3 | Moderate | 3 | 9 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Low | 1 | High | 5 | 5 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | Low | 1 | Low | 1 | 1 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 71 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.18

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Southern California
Congressman Regula's Proposal

Total Score: 214

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 2 | 0.4 | High | 225 | 0.9 |
| Sandy Beaches | 270 | 65.1 | Low | 45 | 29.3 |
| Rocky Beaches | 143 | 34.5 | Moderate | 135 | 46.6 |
| TOTAL | 415 | | | | 76.8 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 101,000 | 0.76 | High | 225 | 1.71 |
| Submarine Canyons | | | Low | 45 | |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 44.66 |
| TOTAL | 13,300,000 | | | | 46.37 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Moderate | 3 | Moderate | 3 | 9 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Moderate | 3 | High | 5 | 15 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | Low | 1 | Low | 1 | 1 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 91 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.19

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Southern California
Congressman Panetta's Proposal
Total Score: 219

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 2 | 0.4 | High | 225 | 0.9 |
| Sandy Beaches | 231 | 48.3 | Low | 45 | 21.7 |
| Rocky Beaches | 231 | 51.5 | Moderate | 135 | 69.5 |
| TOTAL | 478 | | | | 92.1 |
| | | | | | |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 93,000 | 0.32 | High | 225 | 0.72 |
| Submarine Canyons | | | Low | 45 | |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 44.86 |
| TOTAL | 28,700,000 | | | | 45.58 |
| | | | | | |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Moderate | 3 | Moderate | 3 | 9 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Low | 1 | High | 5 | 5 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | Low | 1 | Low | 1 | 1 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 81 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.20a

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Southern California
February 1987 Amalgamated Proposal (Military Areas Included)
Total Score: 193

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 4 | 0.8 | High | 225 | 1.8 |
| Sandy Beaches | 321 | 67.3 | Low | 45 | 30.3 |
| Rocky Beaches | 152 | 31.9 | Moderate | 135 | 43.1 |
| TOTAL | 477 | | | | 75.2 |
| | | | | | |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 107,000 | 0.76 | High | 225 | 1.72 |
| Submarine Canyons | Negligible | 0.00 | Low | 45 | 0.00 |
| Coral Reefs | | | High | 225 | |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 44.66 |
| TOTAL | 14,000,000 | | | | 46.38 |
| | | | | | |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Moderate | 3 | Moderate | 3 | 9 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Low | 1 | High | 5 | 5 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | Low | 1 | Low | 1 | 1 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 71 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.20b

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Southern California — Total Score: 208
February 1987 Amalgamated Proposal (Military Areas Excluded)

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 1 | 0.3 | High | 225 | 0.7 |
| Sandy Beaches | 162 | 50.6 | Low | 45 | 22.8 |
| Rocky Beaches | 157 | 49.1 | Moderate | 135 | 66.3 |
| TOTAL | 320 | | | | 89.8 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 85,600 | 0.98 | High | 225 | 2.20 |
| Submarine Canyons | Negligible | 0.00 | Low | 45 | 0.00 |
| Coral Reefs | | | High | 225 | |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 44.56 |
| TOTAL | 8,700,000 | | | | 46.76 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Moderate | 3 | Moderate | 3 | 9 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Low | 1 | High | 5 | 5 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | Low | 1 | Low | 1 | 1 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 71 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.21

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Southern California — Total Score: 178
Cumulative Deferral

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 1 | 0.8 | High | 225 | 1.8 |
| Sandy Beaches | 106 | 82.8 | Low | 45 | 37.3 |
| Rocky Beaches | 21 | 16.4 | Moderate | 135 | 22.1 |
| TOTAL | 128 | | | | 61.2 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 19,450 | 0.18 | High | 225 | 0.41 |
| Submarine Canyons | | | Low | 45 | |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 44.92 |
| TOTAL | 10,900,000 | | | | 45.33 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Moderate | 3 | Moderate | 3 | 9 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Low | 1 | High | 5 | 5 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | Low | 1 | Low | 1 | 1 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 71 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.22

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Central California
Secretary's Deferrals

Total Score: 229

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 5 | 4.6 | High | 225 | 10.4 |
| Sandy Beaches | 26 | 23.9 | Low | 45 | 10.8 |
| Rocky Beaches | 78 | 71.6 | Moderate | 135 | 96.7 |
| TOTAL | 109 | | | | 117.9 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 15,000 | 0.21 | High | 225 | 0.52 |
| Submarine Canyons | 144,000 | 2.00 | Low | 45 | 0.90 |
| Coral Reefs | 19,000 | 0.26 | High | 225 | 0.59 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 43.88 |
| TOTAL | 7,200,000 | | | | 45.89 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Low | 1 | High | 5 | 5 |
| Marine Birds | Low | 1 | High | 5 | 5 |
| Marine Turtles | Low | 1 | Low | 1 | 1 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 65 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.23

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Central California
Governor's Proposal

Total Score: 113

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | None | 0.0 | High | 225 | 0.0 |
| Sandy Beaches | None | 0.0 | Low | 45 | 0.0 |
| Rocky Beaches | None | 0.0 | Moderate | 135 | 0.0 |
| TOTAL | | | | | 0.0 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | Negligible | 0.00 | High | 225 | 0.00 |
| Submarine Canyons | 247,680 | 4.27 | Low | 45 | 1.92 |
| Coral Reefs | 85,200 | 1.47 | High | 225 | 3.31 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 42.42 |
| TOTAL | 5,800,000 | | | | 47.65 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Low | 1 | High | 5 | 5 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | Low | 1 | Low | 1 | 1 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 65 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.24

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Central California
Congressman Regula's Proposal

Total Score: 100

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | Negligible | 0.0 | High | 225 | 0.0 |
| Sandy Beaches | Negligible | 0.0 | Low | 45 | 0.0 |
| Rocky Beaches | Negligible | 0.0 | Moderate | 135 | 0.0 |
| TOTAL | | | | | 0.0 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | Negligible | 0.00 | High | 225 | 0.00 |
| Submarine Canyons | 144,000 | 8.62 | Low | 45 | 3.88 |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 41.12 |
| TOTAL | 1,670,000 | | | | 45.00 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Low | 1 | High | 5 | 5 |
| Marine Birds | Low | 1 | High | 5 | 5 |
| Marine Turtles | Low | 1 | Low | 1 | 1 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 55 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.25

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Central California
Congressman Panetta's Proposal

Total Score: 110

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | None | 0.0 | High | 225 | 0.0 |
| Sandy Beaches | None | 0.0 | Low | 45 | 0.0 |
| Rocky Beaches | None | 0.0 | Moderate | 135 | 0.0 |
| TOTAL | | | | | 0.0 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | Negligible | 0.00 | High | 225 | 0.00 |
| Submarine Canyons | Negligible | 0.00 | Low | 45 | 0.00 |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 45.00 |
| TOTAL | 12,200,000 | | | | 45.00 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Low | 1 | High | 5 | 5 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | Low | 1 | Low | 1 | 1 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 65 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.26a

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Central California — Total Score: 229
February 1987 Amalgamated Proposal (Military Areas Included)

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| **Coastal Habitats** | Miles | | | | |
| Estuaries/Wetlands | Negligible | 0.0 | High | 225 | 0.0 |
| Sandy Beaches | 1 | 7.7 | Low | 45 | 3.5 |
| Rocky Beaches | 12 | 92.3 | Moderate | 135 | 124.6 |
| TOTAL | 13 | | | | 128.1 |
| **Marine Habitats** | Acres | | | | |
| Submerged Vegetation | 1,000 | 0.05 | High | 225 | 0.11 |
| Submarine Canyons | Negligible | 0.00 | Low | 45 | 0.00 |
| Coral Reefs | 11,400 | 0.57 | High | 225 | 1.29 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 44.72 |
| TOTAL | 1,993,000 | | | | 46.12 |
| **Biota** | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Low | 1 | High | 5 | 5 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Low | 1 | High | 5 | 5 |
| Marine Birds | Low | 1 | High | 5 | 5 |
| Marine Turtles | Low | 1 | Low | 1 | 1 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 55 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.26b

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Central California — Total Score: 229
February 1987 Amalgamated Proposal (Military Areas Excluded)

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| **Coastal Habitats** | Miles | | | | |
| Estuaries/Wetlands | Negligible | 0.0 | High | 225 | 0.0 |
| Sandy Beaches | 1 | 7.7 | Low | 45 | 3.5 |
| Rocky Beaches | 12 | 92.3 | Moderate | 135 | 124.6 |
| TOTAL | 13 | | | | 128.1 |
| **Marine Habitats** | Acres | | | | |
| Submerged Vegetation | 1,000 | 0.06 | High | 225 | 0.14 |
| Submarine Canyons | Negligible | 0.00 | Low | 45 | 0.00 |
| Coral Reefs | 11,400 | 0.70 | High | 225 | 1.56 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 44.66 |
| TOTAL | 1,640,000 | | | | 46.36 |
| **Biota** | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Low | 1 | High | 5 | 5 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Low | 1 | High | 5 | 5 |
| Marine Birds | Low | 1 | High | 5 | 5 |
| Marine Turtles | Low | 1 | Low | 1 | 1 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 55 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.27

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Central California
Cumulative Deferral

Total Score: 80

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | None | 0.0 | High | 225 | 0.0 |
| Sandy Beaches | None | 0.0 | Low | 45 | 0.0 |
| Rocky Beaches | None | 0.0 | Moderate | 135 | 0.0 |
| TOTAL | None | | | | 0.0 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | Negligible | 0.00 | High | 225 | 0.00 |
| Submarine Canyons | Negligible | 0.00 | Low | 45 | 0.00 |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 45.00 |
| TOTAL | 670,000 | | | | 45.00 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Low | 1 | High | 5 | 5 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Low | 1 | High | 5 | 5 |
| Marine Birds | Low | 1 | High | 5 | 5 |
| Marine Turtles | Low | 1 | Low | 1 | 1 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 35 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.28

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Northern California
Secretary's Deferral

Overall Total Score: 222

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 9 | 3.7 | High | 225 | 8.3 |
| Sandy Beaches | 126 | 51.4 | Low | 45 | 23.1 |
| Rocky Beaches | 110 | 44.9 | Moderate | 135 | 60.6 |
| TOTAL | 245 | | | | 92.0 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 7,000 | 0.06 | High | 225 | 0.14 |
| Submarine Canyons | 305,000 | 2.58 | Low | 45 | 1.16 |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 43.83 |
| TOTAL | 11,814,000 | | | | 45.13 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Moderate | 3 | High | 5 | 15 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | Low | 1 | Low | 1 | 1 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 85 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.29

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Northern California
Governor's Proposal

Total Score: 224

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 6 | 5.2 | High | 225 | 11.7 |
| Sandy Beaches | 58 | 50.4 | Low | 45 | 22.7 |
| Rocky Beaches | 51 | 44.3 | Moderate | 135 | 59.8 |
| TOTAL | 115 | | | | 94.2 |

| | | | | | |
|---|---|---|---|---|---|
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 7,000 | 0.20 | High | 225 | 0.27 |
| Submarine Canyons | 305,280 | 8.72 | Low | 45 | 3.92 |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 41.00 |
| TOTAL | 3,502,000 | | | | 45.19 |

| | | | | | |
|---|---|---|---|---|---|
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Moderate | 3 | High | 5 | 15 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | Low | 1 | Low | 1 | 1 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 85 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.30

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Northern California
Congressman Regula's Proposal

Total Score: 190

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | Negligible | 0.0 | High | 225 | 0.0 |
| Sandy Beaches | 49 | 39.2 | Low | 45 | 17.6 |
| Rocky Beaches | 76 | 60.8 | Moderate | 135 | 82.1 |
| TOTAL | 125 | | | | 99.7 |

| | | | | | |
|---|---|---|---|---|---|
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 2,030 | 0.13 | High | 225 | 0.29 |
| Submarine Canyons | 144,000 | 9.47 | Low | 45 | 4.26 |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 40.68 |
| TOTAL | 1,520,640 | | | | 45.23 |

| | | | | | |
|---|---|---|---|---|---|
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Low | 1 | High | 5 | 5 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Low | 1 | High | 5 | 5 |
| Marine Birds | Low | 1 | High | 5 | 5 |
| Marine Turtles | Low | 1 | Low | 1 | 1 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 45 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.31

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Northern California — Total Score: 110
Congressman Panetta's Proposal

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | None | 0.0 | High | 225 | 0.0 |
| Sandy Beaches | None | 0.0 | Low | 45 | 0.0 |
| Rocky Beaches | None | 0.0 | Moderate | 135 | 0.0 |
| TOTAL | None | | | | 0.0 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | Negligible | 0.00 | High | 225 | 0.00 |
| Submarine Canyons | 305,280 | 2.58 | Low | 45 | 1.16 |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 43.84 |
| TOTAL | 11,814,000 | | | | 45.00 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Low | 1 | High | 5 | 5 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | Low | 1 | Low | 1 | 1 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 65 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.32

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Northern California — Total Score: 208
February 1987 Amalgamated Proposal

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 2 | 2.1 | High | 225 | 4.7 |
| Sandy Beaches | 41 | 43.2 | Low | 45 | 19.4 |
| Rocky Beaches | 52 | 54.7 | Moderate | 135 | 73.8 |
| TOTAL | 95 | | | | 97.9 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 2,700 | 0.09 | High | 225 | 0.21 |
| Submarine Canyons | 119,600 | 4.06 | Low | 45 | 1.83 |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 43.13 |
| TOTAL | 2,940,000 | | | | 45.17 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Low | 1 | High | 5 | 5 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Moderate | 3 | High | 5 | 15 |
| Marine Birds | Low | 1 | High | 5 | 5 |
| Marine Turtles | Low | 1 | Low | 1 | 1 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 65 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.33

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Northern California
Cumulative Deferral

Total Score: 80

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | None | 0.0 | High | 225 | 0.0 |
| Sandy Beaches | None | 0.0 | Low | 45 | 0.0 |
| Rocky Beaches | None | 0.0 | Moderate | 135 | 0.0 |
| TOTAL | None | | | | 0.0 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | Negligible | 0.00 | High | 225 | 0.00 |
| Submarine Canyons | Negligible | 0.00 | Low | 45 | 0.00 |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 45.00 |
| TOTAL | 689,000 | | | | 45.00 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Low | 1 | High | 5 | 5 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Low | 1 | High | 5 | 5 |
| Marine Birds | Low | 1 | High | 5 | 5 |
| Marine Turtles | Low | 1 | Low | 1 | 1 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Low | 1 | High | 5 | 5 |
| TOTAL | | | | | 35 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.34

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Washington-Oregon
Secretary's Deferral

Total Score: 256

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 45 | 10.0 | High | 225 | 22.5 |
| Sandy Beaches | 86 | 19.0 | Low | 45 | 8.6 |
| Rocky Beaches | 322 | 71.0 | Moderate | 135 | 95.9 |
| TOTAL | 453 | | | | 127.0 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | | | Moderate | 135 | |
| Submarine Canyons | | | Low | 45 | |
| Coral Reefs | | | High | 225 | |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | |
| TOTAL | 26,200,000 | | | | 45 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Moderate | 3 | High | 5 | 15 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | Negligible | 0 | Low | 1 | 0 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 84 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.35

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Washington/Oregon Governor's (Washington) Proposal — Total Score: 256

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 30 | 10.0 | High | 225 | 22.5 |
| Sandy Beaches | 56 | 19.0 | Low | 45 | 8.6 |
| Rocky Beaches | 210 | 71.0 | Moderate | 135 | 95.9 |
| TOTAL | 296 | | | | 127.0 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | | | Moderate | 135 | |
| Submarine Canyons | | | Low | 45 | |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | |
| TOTAL | 34,000,000 | | | | 45 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Moderate | 3 | High | 5 | 15 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | Negligible | 0 | Low | 1 | 0 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 84 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.36

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Washington/Oregon Governor's (Oregon) Proposal — Total Score: 256

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 27 | 10.0 | High | 225 | 22.5 |
| Sandy Beaches | 51 | 19.0 | Low | 45 | 8.6 |
| Rocky Beaches | 191 | 71.0 | Moderate | 135 | 95.9 |
| TOTAL | 269 | | | | 127.0 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | | | Moderate | 135 | |
| Submarine Canyons | | | Low | 45 | |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | |
| TOTAL | 17,400,000 | | | | 45 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Moderate | 3 | High | 5 | 15 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | Negligible | 0 | Low | 1 | 0 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 84 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.37

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Washington/Oregon — Cumulative Deferral. Total Score: 216

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 11 | 10.0 | High | 225 | 22.5 |
| Sandy Beaches | 21 | 19.0 | Low | 45 | 8.6 |
| Rocky Beaches | 80 | 71.0 | Moderate | 135 | 95.9 |
| TOTAL | 112 | | | | 127.0 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | | | Moderate | 135 | |
| Submarine Canyons | | | Low | 45 | |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | |
| TOTAL | 3,600,000 | | | | 45 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | Low | 1 | High | 5 | 5 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Low | 1 | High | 5 | 5 |
| Marine Birds | Low | 3 | High | 5 | 5 |
| Marine Turtles | Negligible | 0 | Low | 1 | 0 |
| Marine Mammals | Low | 1 | High | 5 | 5 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 44 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.38

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: St. George Basin — Unimak Pass Deferral. Total Score: 267

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | | 0.3 | High | 225 | 0.7 |
| Sandy Beaches | | 26.3 | Low | 45 | 11.9 |
| Rocky Beaches | | 67.5 | Moderate | 135 | 91.1 |
| TOTAL | | | | | 103.7 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | | 1.58 | Moderate | 135 | |
| Submarine Canyons | | | Low | 45 | |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 45.00 |
| TOTAL | 69,300,000 | | | | 45.00 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | High | 5 | High | 5 | 25 |
| Adult Fish/Shellfish | High | 5 | Moderate | 3 | 15 |
| Mud/Sand Benthos | Moderate | 3 | Low | 1 | 3 |
| Coastal Birds | Moderate | 3 | High | 5 | 15 |
| Marine Birds | High | 5 | High | 5 | 25 |
| Marine Turtles | None | 0 | Low | 1 | 0 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 118 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.39

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: St. George Basin — Total Score: 143
Institute for Resource Management Proposal

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | Negligible | 0.0 | High | 225 | 0.0 |
| Sandy Beaches | Negligible | 0.0 | Low | 45 | 0.0 |
| Rocky Beaches | Negligible | 0.0 | Moderate | 135 | 0.0 |
| TOTAL | | | | | 0.0 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | Negligible | 0.0 | Moderate | 135 | 0.0 |
| Submarine Canyons | | | Low | 45 | |
| Coral Reefs | Negligible | 0.0 | High | 225 | 0.0 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | |
| TOTAL | 23,700,000 | | | | 45.0 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | High | 5 | High | 5 | 25 |
| Adult Fish/Shellfish | High | 5 | Moderate | 3 | 15 |
| Mud/Sand Benthos | Moderate | 3 | Low | 1 | 3 |
| Coastal Birds | Low | 1 | High | 5 | 5 |
| Marine Birds | Moderate | 3 | High | 5 | 15 |
| Marine Turtles | None | 0 | Low | 1 | 0 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 98 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.40

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: North Aleutian Basin — Overall Total Score: 326
Unimak Pass Deferral

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | | 32.6 | High | 225 | 73.4 |
| Sandy Beaches | | 13.1 | Low | 45 | 5.9 |
| Rocky Beaches | | 54.3 | Moderate | 135 | 73.3 |
| TOTAL | | | | | 152.6 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | | | Moderate | 135 | |
| Submarine Canyons | None | 0.0 | Low | 45 | 0.0 |
| Coral Reefs | None | 0.0 | High | 225 | 0.0 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | Negligible | 0.0 | Low | 45 | 0.0 |
| Mud/Sand Bottom | | | Low | 45 | |
| TOTAL | 31,650,000 | | | | 45.0 |
| Biota | | | | | |
| Phytoplankton | High | 5 | Low | 1 | 5 |
| Juvenile Fish/Shellfish | High | 5 | High | 5 | 25 |
| Adult Fish/Shellfish | High | 5 | Moderate | 3 | 15 |
| Mud/Sand Benthos | Moderate | 3 | Low | 1 | 3 |
| Coastal Birds | High | 5 | High | 5 | 25 |
| Marine Birds | High | 5 | High | 5 | 25 |
| Marine Turtles | None | 0 | Low | 1 | 0 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 128 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.41

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Navarin Basin — Institute for Resource Management Proposal — Total Score: 141

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | None | 0.0 | High | 225 | 0.0 |
| Sandy Beaches | None | 0.0 | Low | 45 | 0.0 |
| Rocky Beaches | None | 0.0 | Moderate | 135 | 0.0 |
| TOTAL | | | | | 0.0 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | Negligible | 0.0 | Moderate | 135 | 0.0 |
| Submarine Canyons | | | Low | 45 | |
| Coral Reefs | Negligible | 0.0 | High | 225 | 0.0 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | |
| TOTAL | 21,800,000 | | | | 45.0 |
| Biota | | | | | |
| Phytoplankton | Moderate | 3 | Low | 1 | 3 |
| Juvenile Fish/Shellfish | Moderate | 3 | High | 5 | 15 |
| Adult Fish/Shellfish | High | 5 | Moderate | 3 | 15 |
| Mud/Sand Benthos | Moderate | 3 | Low | 1 | 3 |
| Coastal Birds | Low | 1 | High | 5 | 5 |
| Marine Birds | High | 5 | High | 5 | 25 |
| Marine Turtles | None | 0 | Low | 1 | 0 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 96 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.42

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Norton Basin — Yukon Delta Coastal Buffer Deferral — Total Score: 259

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | 544 | 30.4 | High | 225 | 68.6 |
| Sandy Beaches | 382 | 21.4 | Low | 45 | 9.6 |
| Rocky Beaches | 859 | 48.1 | Low | 45 | 21.7 |
| TOTAL | 1785 | | | | 99.9 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 218,000 | 0.89 | Moderate | 225 | 2.00 |
| Submarine Canyons | Negligible | 0.0 | Low | 45 | 0.00 |
| Coral Reefs | Negligible | 0.0 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 44.60 |
| TOTAL | 24,500,000 | | | | 46.60 |
| Biota | | | | | |
| Phytoplankton | Moderate | 3 | Low | 1 | 3 |
| Juvenile Fish/Shellfish | Low | 1 | High | 5 | 5 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | High | 5 | High | 5 | 25 |
| Marine Birds | High | 5 | High | 5 | 25 |
| Marine Turtles | None | 0 | Low | 1 | 0 |
| Marine Mammals | High | 5 | High | 5 | 25 |
| Whales | High | 5 | High | 5 | 25 |
| TOTAL | | | | | 112 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.43

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Norton Basin — Total Score: 137
Institute for Resource Management Proposal

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | None | 0.0 | High | 225 | 0.0 |
| Sandy Beaches | None | 0.0 | Low | 45 | 0.0 |
| Rocky Beaches | None | 0.0 | Low | 45 | 0.0 |
| TOTAL | | | | | 0.0 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | Negligible | 0.00 | Moderate | 135 | 0.00 |
| Submarine Canyons | Negligible | 0.00 | Low | 45 | 0.00 |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 45.00 |
| TOTAL | 3,500,000 | | | | 45.00 |
| Biota | | | | | |
| Phytoplankton | Moderate | 3 | Low | 1 | 3 |
| Juvenile Fish/Shellfish | Low | 1 | High | 5 | 5 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | Low | 1 | High | 5 | 5 |
| Marine Birds | High | 5 | High | 5 | 25 |
| Marine Turtles | None | 0 | Low | 1 | 0 |
| Marine Mammals | High | 5 | High | 5 | 25 |
| Whales | High | 5 | High | 5 | 25 |
| TOTAL | | | | | 92 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE I-3.44

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Beaufort Sea — Total Score: 257
Point Barrow Deferral

| | Distribution of Resource (1) | (2) | Sensitivity Coefficient (3) | (4) | Score (5) |
|---|---|---|---|---|---|
| Coastal Habitats | Miles | | | | |
| Estuaries/Wetlands | | 52.9 | High | 225 | 119.0 |
| Sandy Beaches | | 46.9 | Low | 45 | 21.1 |
| Rocky Beaches | | 0.2 | Moderate | 135 | 0.1 |
| TOTAL | | | | | 140.2 |
| Marine Habitats | Acres | | | | |
| Submerged Vegetation | 250,000 | 0.51 | Moderate | 135 | 0.69 |
| Submarine Canyons | | | Low | 45 | |
| Coral Reefs | Negligible | 0.00 | High | 225 | 0.00 |
| Hard Bottoms | | | Low | 45 | |
| Shelf Break Zone | | | Low | 45 | |
| Mud/Sand Bottom | | | Low | 45 | 44.77 |
| TOTAL | 49,100,000 | | | | 45.46 |
| Biota | | | | | |
| Phytoplankton | Low | 1 | Low | 1 | 1 |
| Juvenile Fish/Shellfish | Low | 1 | High | 5 | 5 |
| Adult Fish/Shellfish | Low | 1 | Moderate | 3 | 3 |
| Mud/Sand Benthos | Low | 1 | Low | 1 | 1 |
| Coastal Birds | High | 5 | High | 5 | 25 |
| Marine Birds | Low | 1 | High | 5 | 5 |
| Marine Turtles | None | 0 | Moderate | 3 | 0 |
| Marine Mammals | Moderate | 3 | High | 5 | 15 |
| Whales | Moderate | 3 | High | 5 | 15 |
| TOTAL | | | | | 70 |

(1) Linear or areal extent of habitat; relative abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

# APPENDIX J

## AVAILABILITY OF TRANSPORTATION NETWORKS TO BRING OIL AND GAS TO REGIONAL ENERGY MARKETS

AVAILABILITY OF TRANSPORTATION NETWORKS TO BRING OIL AND GAS TO REGIONAL ENERGY MARKETS

CONTENTS





AVAILABILITY OF TRANSPORTATION NETWORKS TO BRING OIL AND GAS TO REGIONAL ENERGY MARKETS

## I. Introduction

Section 18(a)(2)(C) requires that the timing and location of Outer Continental Shelf (OCS) oil and gas operations be based upon a consideration of the location of oil and gas bearing physiographic regions with respect to, and the relative needs of, regional and national energy markets. To provide for such consideration, an analysis of the availability of transportation networks has been prepared.

A previous analysis was included as Appendix 4 of the 1982 Secretarial Issue Document (SID) prepared for the 5-year Oil and Gas Leasing Program. The analysis divided the transportation issue into two parts--bringing oil and gas resources to shore and transporting landed resources to refinery and demand centers. The transportation analysis presented below uses the same framework to review and analyze the availability of oil and gas transportation networks.

In analyzing the availability of transportation networks to deliver oil and gas to demand areas, both current and proposed networks were reviewed for all OCS planning areas. In addition, data submitted by State and local governments, Federal Agencies, industry, and the public in response to letters to the Governors of affected States and to the heads of relevant Federal Agencies, dated July 5, 1984, a July 11, 1984, Federal Register Request for Comments, and comments on the February 1986 Proposed Program were also used. The results of this analysis have confirmed that the decision of whether to use pipelines, barges, or tankers to transport OCS oil and gas to shore is dependent on a number of factors, including technological constraints, environmental preferences, and economic considerations. The exact mode of transport cannot be determined until the amount of recoverable reserves is known and judgments are made as to what is environmentally preferable and technically and economically feasible.

Further, it is understood that in order for a hydrocarbon find to be economically feasible, an accessible transportation system must be in existence or a new one must be created. Transportation systems are not built in anticipation of hydrocarbon discoveries. This is especially true in frontier areas where knowledge of hydrocarbon resources is spotty or nonexistent and anticipated transportation costs are generally very high due to the lack of existing infrastructure.

Based on previous analysis and completed projects, pipelines are generally preferred by the oil companies for transporting oil and gas to processing facilities when economics and other considerations justify their construction. Where pipelines cannot be justified, tankers or barges are necessary. In California, although pipelines have almost always been used over tankers, in some instances tankers are preferred by the oil industry. Tankers, in some cases, allow greater flexibility in terms of getting oil to refineries and market centers. Not all of the oil companies have local refineries or local refineries with the capability of handling high sulfur or heavy crude like that being found off California.

The present analysis is limited to examination of issues related to transport of product among domestic market areas. There has been extensive public debate for and against sale and transport of Alaskan crude oil to Japan. Such sales currently are prohibited by Federal law. If authorized, OCS oil and gas resources could be delivered more cheaply to Japan than to many domestic market areas.

II. Transporting Oil and Gas Resources to Shore

At present, pipelines are generally used to bring oil and gas ashore in both the Gulf of Mexico and Southern California planning areas. The Gulf of Mexico is the only area with an extensive pipeline system, including a network of oil and gas gathering systems and trunk lines. In Southern California, the only other commercially producing OCS area, pipelines are desirable because, once installed, they generally do not adversely affect air quality commonly associated with tanker terminal use. The State of California also prefers pipelines due to their belief that there is a lower risk of oil spills. However, tankers are employed in Southern California in a variety of situations to transport oil to refineries.

Expansion of the offshore oil and gas pipeline systems in Southern California and the Gulf of Mexico is continuing as needed to extend pipelines into new production areas. For example, a number of discoveries have been announced in the Santa Maria Basin on the California OCS. As as result, several large production projects are expected to be coming on line in the near future and are likely to transport oil and gas ashore by new pipelines to a consolidated onshore processing facility. Also, OCS development support facilities within California are being consolidated to minimize the number of pipeline landfalls. Similarly, any new production in the Central and Western Gulf of Mexico is also expected to use pipelines. In many cases, only new gathering lines are likely to be required in the Gulf of Mexico region to connect with existing trunk systems.

In areas where there is currently no production, such as the Atlantic OCS, an alternative transportation system may be required. Because of both the size and location of potential Atlantic OCS fields, it is expected that all Atlantic OCS crude would be transported to shore by tankers. The same is likely to be true for any oil found where the resources may not economically justify pipelines, for example in Central and Northern California and in the Eastern Gulf of Mexico.

As there is not yet any oil and gas production on the Alaska OCS, transportation systems there are still speculative. However, three basic networks have been identified based on geography. The first involves oil and gas transportation from the Beaufort Sea, Chukchi Sea, and Hope Basin planning areas. Produced crude oil is expected to be transported through subsea and overland pipelines to the Trans-Alaskan Pipeline System (TAPS), where it would be routed to the Valdez tanker terminal.

Ice-breaking tankers are still being considered as a viable option to pipelines in many of the planning areas in Alaska including the western portion of the Chukchi Sea and Hope Basin. Tankering may be economically viable and may be the form of transportation selected by industry in Alaska as it was selected, for example, in the North Sea for marginal fields in their initial stage of production.



Anticipated OCS production is not likely to exceed TAPS capacity and is expected to actually replace production from the Alaskan North Slope (ANS) which is estimated to decline rapidly in the late 1990's.

The TAPS began transporting crude oil from the ANS to Valdez on June 10, 1977. TAPS is a 48-inch diameter line designed to have a potential capacity of 2.0 million barrels per day, although 1.7 million barrels per day has been set as the maximum efficient rate by the Alaska Oil and Gas Conservation Commission.

The terminal at Valdez is able to handle four tankers at one time and has an average turnaround time of 24 hours. TAPS is presently delivering crude oil from Prudhoe Bay which initially had an estimated 9.6 billion barrels of recoverable oil reserves and from Kuparuk which had an estimated 1.6 billion barrels of recoverable oil reserves.

There is currently no system available to transport natural gas from the Prudhoe Bay area of the Alaska OCS to the contiguous United States. Based on current cost/price relationships and foreseeable technological advances, the gas resources estimated for the Beaufort Sea and Chukchi Sea planning areas are assumed in the SID analysis to be uneconomic. The Alaskan Natural Gas Transportation System (ANGTS) had been proposed to carry North Slope and Canadian natural gas to the lower 48 States. The pipeline is currently delivering gas from north of Calgary, Alberta to Iowa and Oregon. However, the Alaskan and northern Canadian sections of the pipeline remain unbuilt. Sponsors of the ANGTS have announced delay in the target date for completion of the line, citing inability to obtain funding. Some analysts argue that the pipeline's estimated cost makes completion of the project economically impractical. Others contend that current economic conditions have only delayed its completion. If completed, the pipeline would carry North Slope and Canadian natural gas to markets as far away as Chicago and San Francisco. Another pipeline, the All Alaska Natural Gas Pipeline, has been proposed to transport the North Slope gas to Kenai, Alaska for processing and transportation.

In the absence of a pipeline, other gas transportation systems are being considered including liquefaction of natural gas (LNG) and conversion of gas to methanol. Industry indicates that the technology exists to use gathering lines to a grounded barge with prefabricated facilities for processing, storage, and utilities and to then tanker LNG to a terminal. The major problems lie in operating tankers in a hostile environment. Tankers designed with ice breaking capability and otherwise modified for operations in an arctic environment are believed to be feasible.

LNG terminals could also be mounted on an offshore platform, although offshore fixed storage and loading facilities are only in the conceptual stage of development. The technology for an LNG transfer system from a fixed platform to floating storage or tankers appears to be available for Alaskan offshore waters but has not been proven. Onshore LNG terminals now exist in Quincy, Massachusetts; Cove Point, Maryland; and Savannah, Georgia.

The second oil transportation scenario for Alaska encompasses possible production within the St. George Basin, Norton Sound, Navarin Basin and the North Aleutian Basin planning areas. Transportation projections for these planning areas feature a series of gathering and trunk lines feeding into a central offshore or onshore terminal. Ice-breaking shuttle tankers would be used to move the crude to an ice-free deepwater port on the Southern Alaskan peninsula for transshipment. As an alternative, it is possible that potential OCS production from the North Aleutian Basin would be piped directly to the transshipment terminal.

As another alternative, industry is currently indicating that ice-breaking tankers could be used to transport the product directly to market, without using any shuttle tankers, which minimizes the problems with potential spills associated with unloading and reloading. The vessels can use a variable pitch propeller system, which will give them power in the ice and speed in the open water.

The transportation of crude oil from OCS operations in the Bering Sea would require the construction of new tanker facilities. While weather conditions are severe in these areas, sea conditions would not preclude the use of conventional tankers during most of the year. The supply of tankers is not expected to pose a constraint on development of leases issued during the 1987-1992 time period.

The third scenario includes the Shumagin Basin, Kodiak, Cook Inlet, and Gulf of Alaska planning areas. If production from these OCS areas were to occur, it would likely be moved through subsea pipelines to storage facilities prior to being tankered directly to market. Some new tanker facilities would likely be required.

III. Transporting Landed Resources to Refinery and Demand Centers

The existing refinery and continental pipelines system in the Gulf Coast imposes no constraint on processing and distribution of anticipated OCS production. It is assumed that all Gulf OCS production will be landed in the Gulf and processed and distributed in response to market conditions. For a variety of reasons, more detailed analysis is required for West Coast OCS production.

Transportation networks do not pose a major constraint to further subarctic OCS production, as they will be modified to serve economically viable hydrocarbon discoveries. The availability of current transportation networks will, in fact, facilitate the development of OCS resources which can make use of those networks. The factors restricting transportation network availability and, potentially, OCS production, will be the environmental and economic costs associated with establishing and operating the necessary transportation systems. Transportation costs and availability are carefully considered when evaluating the economic feasibility of every hydrocarbon discovery. Resource development will not occur unless the hydrocarbons can be economically transported to regional and national markets.



As an example, the economic benefits analysis presented in Appendix F does not include benefits from the production of natural gas resources in the Beaufort or Chukchi planning areas due to expected high production costs, consisting largely of transportation costs. In addition, the economic benefits analysis in Appendix F arrives at the net economic value of production of the oil and gas resources by subtracting from it the costs of developing and transporting those resources to market. Environmental costs associated with transportation of production are taken into account in the calculation of social costs (Appendix G).

Specific assumptions are made to allocate OCS oil production between West and Gulf Coast refineries. Forecast Petroleum Administration for Defense District (PAD) V (Alaska, Hawaii, Washington, Oregon, California, Arizona, and Nevada) refining capacity is used as an upper bound on deliveries of OCS oil. Both onshore and OCS production from California, Oregon, and Washington are allocated to PAD V refineries. Alaska OCS oil and other Alaskan oil are allocated to excess PAD V refinery capacity proportionately. The excess PAD V refinery capacity is calculated by subtracting the estimated production in California, Oregon, and Washington from the PAD V refining capacity. Most Alaskan and West Coast production not refined in PAD V is expected to be delivered to the Gulf Coast area for refining. An extensive pipeline system originating in the Gulf along with transport of refined products by barge and tanker will allow delivery to market centers throughout much of the country.

In 1984, there were 47 operating refineries in PAD V with 4 idle refineries. Six refineries in PAD V became inoperable between 1983 and 1984. The 47 operating refineries in PAD V produced 2.460 million b/d of products during 1984 and the total capacity of operating and idle refineries was 2.995 million b/d. The decline in PAD V refinery capacity during 1984 was consistent with a nation-wide pattern of reduced refinery capacity which started in 1981. Over the 5-year period, national refining capacity dropped by almost 22 percent (Oil and Gas Journal, March 18, 1985).

Explicit assumptions concerning future refining capacity and demand for petroleum in PAD V will provide a basis for estimating how much West Coast OCS oil will likely be refined and consumed on the West Coast and how much West Coast OCS oil will likely be shipped to the Gulf Coast for refining and use. The Department of Energy was consulted to obtain a forecast of future petroleum consumption in PAD V. Across all petroleum consuming sections the demand for refined products in PAD V is estimated to be approximately 2.75 million b/d in the year 2000 and 2.6 million b/d in the year 2010.

The PAD V consumption forecast must be augmented by a forecast of future export of refined products to have an estimate of total future PAD V refining capacity. In 1984, PAD V had net product export of 122.7 thousand b/d. Thus, net exports amount to approximately 4.5 percent of total refinery production. Increasing the forecast demand for petroleum production in the years 2000 and 2010 by 4.5 percent would increase the refinery production estimate to 2.87 million b/d in 2000 and 2.7 million b/d in 2010. The Department of Energy has not forecast expected future product exports from PAD V. Estimates of approximately 2.9 million b/d in 2000 and 2.7 million b/d in 2010 will be used in allocating Alaskan and West Coast OCS oil between PAD V refineries and refineries in the Gulf of Mexico.

It is perhaps, relevant to note that the estimate of 2.9 million b/d for the year 2000 is slightly less than the total capacity of operating and idle refineries in PAD V during 1984. Between 1984 and 2000 PAD V refining capacity is assumed to equal 2.9 million b/d and a straight line decline is used between 2000 and 2010.

The estimated total production in PAD V exceeds expected PAD V refining capacity past the year 2010. Transportation of part of the PAD V surplus by pipelines is expected. There are presently three pipelines in various stages of planning and development which may be available for delivery of West coast oil to Gulf coast refining centers. The proposed projects include the recently completed All-American Pipeline from Santa Barbara, California, to Midland, Texas, with a 300,000 b/d capacity; the Pacific-Texas pipeline from Long Beach, California, to Midland, Texas, with a proposed throughput of 900,000 b/d; and the expansion of the existing Four Corners pipelines to a proposed capacity of 150,000 b/d from Long Beach to New Mexico. For purposes of this analysis, it is assumed that pipeline transportation for PAD V oil will be operational by 1995. The capacity of pipeline transportation assumed in this analysis is 500,000 b/d.

Demonstration of the method for allocating Alaskan oil to West and Gulf coast refineries is provided by explaining the calculations for the year 2000 which use $29/barrel resource estimates. PAD V refining capacity is estimated to be 2.9 million b/d. Additionally, 0.5 million b/d of pipeline capacity is assumed. Production for the Pacific OCS (all three California planning areas plus Washington and Oregon) is estimated to be 0.377 million b/d and onshore production is estimated to be 2.384 million b/d. Subtracting these estimates of 2000 production from the estimate of PAD V refining and pipeline capacity provides an estimate of surplus PAD V refining capacity--0.639 million b/d. This surplus is allocated between Alaska OCS and Alaska onshore oil proportionately which results in 0.048 million b/d of the estimated 0.134 million b/d being allocated to PAD V refineries with the rest going to the Gulf of Mexico PAD III refineries. Similar calculations were made for each year between 1995 and 2010. After 2010 all Alaskan OCS oil production can be refined in PAD V. Summing across the period 1995 - 2020 produces an estimate of the total amount of Alaska OCS oil that is allocated to West and Gulf Coast refineries. The results for $29/barrel oil price estimates are that 486 million barrels of Alaska OCS oil production can be delivered to PAD V refineries and 270 million barrels will have to be shipped to PAD III for refining.*

In the past, concern has been expressed that the low gravity, high sulfur crude oil found on the California OCS and the low gravity oil from the Alaska North Slope could not be refined in most California refineries without violating California air quality standards. Retrofitting refineries to allow operations to meet air quality standards while processing lower quality crudes is expensive. Still, some California refineries are currently being modified to handle the lower quality crude oil expected to be produced in the near future.

* When $24/barrel or lower price scenario resource estimates are used in these calculations, the results are that all Alaskan and Pacific OCS oil production would most likely remain on the West Coast.



No additional refineries are expected for the Gulf of Mexico region or the Atlantic Coast. In 1982, refineries in the Gulf were operating at approximately 65 percent of total capacity; Atlantic Coast refineries are currently (October 1984) operating at about 66 percent of capacity. Some retrofitting of existing facilities has occurred in the Gulf to accommodate low quality Alaska and California crude oil.

# APPENDIX K

# FAIR MARKET VALUE

## FAIR MARKET VALUE

CONTENTS



Appendix K

# FAIR MARKET VALUE

## I. Introduction

The Secretary of the Interior, in formulating an Outer Continental Shelf (OCS) oil and gas leasing program, is required to assure the receipt of fair market value for the lands leased and the rights conveyed by the Federal Government. Such an assessment requires an analysis of the term "fair market value." This is a term with both legal and economic meaning. "Market value" has its origin in the world of economics--the marketplace, an exchange of goods and services at a price determined by a willing buyer and a willing seller. The term "fair" is more elusive and is subject to interpretation. The question arises as to whether "fair" modifies the term "market" or the term "market value." An examination of both meanings of the term, however, is not mutually exclusive; rather, it is sequential: (1) What are the determinants of a fair market? (2) Does the existence of a fair market assure the receipt of fair market value?

One of the many factors the Secretary must weigh in creating a leasing program is the principle that "leasing activities shall be conducted to assure receipt of fair market value for the lands leased and the rights conveyed by the Federal Government." (See 43 U.S.C. 1344(a)(4)1.) This is distinct from the economic principles around which the 5-year program is designed, including maximizing the Nation's income.

This appendix discusses how the Department assures receipt of fair market value and the economic concepts and mechanisms which provide the foundation for generating fair market value for OCS oil and gas leases. Section II presents the legal requirements and judicial interpretations of fair market value under the OCS Lands Act. Section III focuses on the OCS oil and gas lease market and the role of competition in generating value. Section IV discusses the factors and methodology which are considered by both Government and the private sector in evaluating OCS oil and gas for potential exploration and development. Section V discusses the Government's procedures to assure receipt of fair market value and Section VI indicates the context in which the fair market value requirement must be considered with the other requirements of the OCS Lands Act governing the management of these resources. It discusses the issue of fair market value not being synonymous with maximization of government receipts.

## II. Legal Requirements and Judicial Interpretations of Fair Market Value

Section 18(a)(4) of the OCS Lands Act requires the formulation of an OCS oil and gas leasing program consistent with the following principle:

> Leasing activities shall be conducted to assure receipt of fair market value for the lands leased and the rights conveyed by the Federal Government.

Section 2(o) of the act defines "fair market value" as it applies to the value of "any mineral" but not to the value of the lands leased and the rights conveyed. The Conference Report on S.9 states that the term as so defined "is only used in the Act in relation to the purchase and distribution of oil and gas under Section 27." That section pertains to Federal purchase and disposition of royalty oil and gas in kind. "Fair market value," as it applies to lands leased and rights conveyed, is thus not explicitly defined by the OCS Lands Act.

In the 1982-1987 5-year program, the Secretary adopted the following definition:

> "Fair market value" is defined as the amount in cash, or in terms reasonably equivalent to cash, for which in all probability the property would be sold by a knowledgeable owner willing but not obligated to sell to a knowledgeable purchaser who desired but is not obligated to buy.

The U.S. Court of Appeals for the District of Columbia Circuit was asked to determine whether the Secretary could meet the statutory requirement "to assure receipt of fair market value for the lands leased and the rights conveyed" by OCS oil and gas leases, in light of the fact that the "accelerated rate of leasing might ordinarily result in less intense competition and lower bids for some tracts." (See California v. Watt, 712 F.2d at 584, U.S. Court of Appeals, District of Columbia Circuit, July 5, 1983.) The court ruled that, despite the lower bids expected, "the proposed evaluation process, coupled with the Secretary's reasonable reliance on the integrity of the competitive bid process, is sufficient to assure that the fair market value is received. The statute requires nothing more." (See 712 F.2d at 608.)



## III. Characteristics of the OCS Lease Market

Drawing upon the definition of fair market value provided by the Interagency Land Acquisition Conference (Interagency Land Acquisition Conference, Uniform Appraisal Standards for Federal Land Acquisitions, 1973) which states in part: "Fair market value is defined as the amount in cash . . . for which in all probability the property would be sold by a knowledgeable owner willing but not obligated to sell to a knowledgeable purchaser who desired but is not obligated to buy.", we analyze its application to the OCS lease market in terms of:

- what is the "property" being sold; and
- what characterizes knowledgeable buyers and sellers willing but not obligated to buy or sell.

The property (product) being sold in the OCS lease market, characterized by numerous private buyers and one public seller, is the right to explore, develop, and produce oil and gas on designated offshore lands in an expeditious manner and in accordance with other restrictions imposed on the lessee, some of which may be imposed after the lease is issued. There is no guarantee that the property leased will contain oil and gas; if oil and gas are found and the quantities discovered are economic to produce, their production and the resulting cash flows may extend from 5 to 25 years into the future.

The structure of the lease market for the exchange of these rights between buyers and sellers is established by the OCS Lands Act.

The act provides that oil and gas leases are to be sold by competitive sealed bidding and thus establishes the requirement of a competitive market structure to generate the value of OCS oil and gas leases. In practice, the determination of fair market value for the high bid is based only on the amount of the bid (relative to the MMS quantitative measures of bid adequacy) given that the high bidder is qualified to conduct OCS operations.

One characteristic of a competitive (i.e., fair) market is the ability of the market to generate a competitively determined value among buyers and sellers not operating under coercion or restraints to entry and without the imposition of artificial barriers to competition. A competitive market is thus characterized by "knowledgeable buyers and sellers willing but not obligated to buy or sell."

Knowledgeability of buyers and sellers in a competitive market does not equate with a perfect and equal level of knowledge, rather, it pertains to buyers and sellers having reasonable knowledge of the relevant facts. In the case of OCS oil and gas leases, there are high levels of uncertainity associated with the variables affecting the value of a lease (section IV discusses this in more detail). In addition, interpretation of that knowledge differs from bidder to bidder and from the Government to the private sector. If there are no artificial constraints or barriers to acquiring that knowledge, the competitive market mechanism will not be hampered. The Government, as seller, combines its knowledge of the working of the market along with geological, geophysical, engineering, and economic interpretations to assure fair market value.

Markets in which coercion or entry restraints are operative will generate values which may be artificially constrained. The OCS Lands Act provides for a review prior to the final award of leases to help assure that the OCS market is free from collusion. Under section 8(c), the Federal Trade Commission and the Antitrust Division of the Department of Justice review pending lease awards for effects on competition, and the Attorney General is authorized to make recommendations to the Secretary to prevent any situation inconsistent with the antitrust laws. Based on such recommendations or on his own motion, the Secretary may refuse to accept a high bid or issue a lease. (These reviews have never identified collusive behavior among bidders for OCS leases.)

In the OCS lease market, the potential competition for individual leases is an important factor in bid formulation. Bidding theory recognizes that, in addition to the tract-specific evaluations (discussed in section IV), expected competition is a factor that should be taken into account in bid formulation (E. C. Copen, R. V. Clapp, and W. M. Campbell. "Competitive Bidding in High Risk Situations," Journal of Petroleum Technology, 23, 1971, pp. 641-653, and J. G. Riley and W. F. Samuelson. "Optimal Auctions," American Economic Review, 71, June 1981, pp. 381-392). Although it may seem counterintuitive, theory indicates that bidders generally should reduce their bid when the expected number of competitors increases beyond two. Thus, the tendency for the high bid to increase as competition increases is, at least in theory, not necessarily due to each bidder bidding higher, but rather because there are more bids from which the high bid will emerge.

Both theoretically and empirically, the high bid tends to increase as the number of bids increases on a tract with a given value estimate. The OCS Task Force Report on Fair Market Value (February 1983) concluded, based on the historical average of recorded competition (as measured by the number of bids received), that when three or more prospective buyers submit a bid for an oil and gas lease, competition in the marketplace is sufficient to assure a fair return to the seller. (This conclusion was qualified in the event that a sale had an average number of bids in excess of three and for wildcat and proven tracts, on which one prospective buyer may have a large information advantage over other prospective buyers.

The Secretary's "reasonable reliance on the integrity of the competitive bid process" to generate fair market value is reflected in the procedures used to determine bid adequacy and assure fair market value on a lease-specific basis. The following section examines the method and factors which are considered in assessing value for OCS oil and gas leases.



## IV. Factors Affecting Value: Methodology Used in Determining Value

The Interagency Land Acquisition Conference went on to state regarding fair market value that "In ascertaining that figure, consideration should be given to all matters that might be brought forward and reasonably be given substantial weight in bargaining by persons of ordinary prudence . . . ."

There are a series of factors exogenous to the OCS lease market, itself, which are considered in evaluating specific tracts or in "ascertaining that figure.". The standard methodology used in petroleum evaluations is a probabilistic discounted cash flow model. The methodology incorporates assessments of all major factors affecting the value of a lease over its potential life; namely, the timing of exploration and development activities, future prices of oil and gas, costs of exploration, development and production, inflation rates, and tax considerations.

Furthermore, all of the major inputs used in assessing the value of OCS oil and gas leases change over time. For example, knowledge of the physical or geological nature of the resource, based on geological and geophysical data, changes as information is acquired from leases and permits, thus affecting positively or negatively the value of tracts remaining to be leased. The costs and the timing of exploration, development, and production are influenced by the location of the resource--whether it is located in remote locations with no current means of transportation or in unusually deep water hundreds of miles from shore. The value of OCS oil and gas leases is also influenced by current and expected future prices of the end product--oil and gas. These prices are critical in determining the amount that bidders will pay for OCS leases, regardless of the size and timing of tract offerings. The domestic price of oil and gas is largely determined in the international market, strongly influenced by the OPEC nations because of their control over large quantities of low cost reserves. Individual companys' investment portfolios and capital budgets are also factors which they consider in valuing OCS oil and gas leases.

The end result of these assessments is a range of potential values for an oil and gas lease which reflects the uncertainties of the input factors. From the buyers' point of view, the residual value resulting from this type of evaluation represents the potential profitability of a lease. From the Government's point of view, the measures developed using the same type of technique result in an estimate of a value which, on a lease-specific basis, is used as an initial step in estimating the minimum acceptable bid in order to judge whether the high bid received meets the fair market value requirement. Simultaneously, this approach provides for the consideration of important factors to "be given substantial weight" in determining market value.

The competitive sealed bidding process of the OCS lease market is the market mechanism which is used to interpret market value at a specific point in time (i.e., a sale). However, there are possibilities in the OCS lease market which could allow bids to be submitted which, without the exercise of a prudent assessment by the Government, could result in less than a fair market value. Where information asymmetry exists, such as on drainage and development tracts on which the adjacent owner has privileged information or on wildcat and proven tracts that involve development technologies unique or limited to selected companies, the corresponding bid may be skewed and other parties may choose not to bid. In order to assure fair market value as the law requires and the courts have interpreted, the Secretary has developed a set of procedures which reflect an understanding of the workings of the OCS lease market in generating values and bids. He has structured the procedures to assure receipt of fair market value by relying on the fair market to generate fair market value and by relying on Government evaluations to assure that market values being generated for certain categories of tracts are indeed fair; otherwise, the high bids are rejected and the tracts reoffered at a later date.

The Government, as seller of the leases and controller of the rate of leasing (size and timing of lease sales), may have some capability to influence the overall level of bidder activity (competition) in the OCS oil and gas lease market. Section V examines this influence and the procedures established for assuring fair market value.

The assurance of fair market value is relevant to lease sale schedule formulation only to the extent that the timing of lease sales can be shown to result in a market that does not operate competitively. For example, since bidders on OCS tracts must gather data, prepare bids, and be ready to conduct exploration efforts, sale timing could limit their ability to participate, thus hampering competition and the receipt of fair market value. Also, if sales were too rapid or made on very short notice, competition could be hampered because of industry's inability to budget or plan for lease sales, including the acquisition of geological and geophysical data and evaluation of tracts.

One important objective considered in formulating a leasing schedule is to maximize national income from leasing activities. The methodology used in Appendix F provides information on net economic value for each planning area to use for relative comparisons for scheduling purposes. This conceptual framework and the factors which it takes into consideration require an understanding of existing and projected market conditions affecting OCS oil and gas leasing rates. Fair market value assurance, however, takes the world market conditions as given and has as its primary objective the assurance that the conditions within the U.S. OCS oil and gas lease market, itself, generate a fair return to the Government. Procedures to assure the receipt of fair market value which reflect an understanding of the competitive mechanism of the OCS lease market are discussed in the following section.



## V. Discussion of Procedures to Assure Fair Market Value

Throughout the history of the OCS leasing program, assuring receipt of fair market value has been a constantly evolving process. In the late 1960's, the Department of the Interior began placing an independent cash value on every tract offered for lease. During the mid-1970's, the Department began using market information in the bids received along with the Government's estimated independent tract evaluation to make accept/reject decisions. This gave recognition to the concept that fair market value, as a price in a competitive market, should reflect values offered by prospective buyers operating in the economic climate prevailing at the time of the lease sale as well as the seller's value.

In July 1982, a Department-wide task force was established to develop and test various methods for determining bid adequacy in light of the Secretary's legal requirement to assure receipt of fair market value in conjunction with the new leasing program proposed at that time. In February 1983, the Department adopted the recommended procedures of the task force which consisted of a two-phase bid adequacy process which used tract classification and actual bid data to evaluate tracts receiving bids in order to determine which tracts required detailed analysis and which tracts the competitive market forces could be relied upon to assure receipt of fair market value. Phase 1 includes market-oriented evaluation criteria for accepting some bids on some blocks and determining what other bids will receive further evaluation in Phase 2. Phase 1 is composed of criteria designed to partition tracts receiving bids into three general categories:

- those receiving bids which MMS has identified as being nonprospective for commercial accumulations of hydrocarbons;
- those where opportunities for strategic underbidding, information asymmetry, collusion, and other noncompetitive practices might most likely occur and where the Government has detailed and reliable data; and
- those where the competitive market forces can be relied upon to assure fair market value.

Phase 2 provides for the application of criteria designed to further determine bid adequacy on a tract-specific basis and uses independent Government evaluations in addition to the bid data to determine bid acceptance/rejection.

In 1984 and 1985, modifications were made to the OCS bid adequacy procedures to incorporate knowledge gained from their actual use in areawide lease sales. On the surface, there has been an observable overall decrease in the average bonus bid per acre in recent years. This trend actually began in price of oil and the overall quality and location of tracts being offered for 1982 in tract selection-type sales. There has also been an increase in the number of one-bid tracts. Analysis of these observations was due to myriad of factors, the most significant ones appear to be the decrease in the expected price of oil and the overall quality and location of tracts being offered for lease. A 50-percent drop in the real world price of oil, along with projections of lower rates of future price growth, have significantly influenced the present value of tracts being offered. Further, the sales and leasing of tracts in areawide sales have seen industry moving into deepwater, high-cost, high-risk areas of mature OCS planning areas and into high-cost, high-risk frontier areas--a trend which barely began when tract selection-type sales were held. Market forces are operating to reflect these conditions. (See Appendix P.)

Because many of the tracts offered for sale recently have marginal potential for hydrocarbon resources (they have been offered before and not leased or have been leased and relinquished), more one-bid tracts have been generated. In order to continue to assure fair market value within the changing conditions of the OCS lease market, technical adjustments in the bid adequacy procedures have been made based on the Government's analysis of these changing market conditions. For example, in the initial areawide lease sales a geomean rule was used as one of the market-oriented bid criteria for bid acceptance in Phase 1. This rule provided for the acceptance of bids on wildcat and proven tracts if the geometric mean of the bids received on the tracts was greater than the median of the geometric means of bids received on prospective wildcat and proven tracts. This rule is no longer used as a market-oriented criteria for bid acceptance based on analysis indicating that the geometric mean is a considerably less useful statistical measure of bidding behavior when there is a greater proportion of tracts receiving fewer bids. As a result, more tracts now receive further evaluations. Nevertheless, the basic conceptual framework of the bid adequacy procedure has not been modified and satisfies the legal requirement of assuring fair market value by instituting a process which assesses the workings of the market on a tract-specific basis in determining a fair return. Reliance is placed on the marketplace as well as the Government's independent assessment.

Based on analyses, studies, and experience with the oil and gas leasing market, categories of tracts for which the bids may not assure fair market value are subjected to additional independent Government evaluation. All evaluations incorporate the use of the latest geological, geophysical, and economic evaluation methodologies and account for the inherent uncertainties of all the major variables. The 1985, GAO study of MMS's procedures for tract evaluation titled "Interior Has Taken Steps to Improve the Adequacy of Data Used for Making Outer Continental Shelf Leasing Decisions," recognized MMS's continuing improvement of its procedures and data for tract evaluation purposes.

The following procedures for OCS bid adequacy are currently in effect for all OCS lease sales. They provide for the application of criteria in a two-phased process for bid adequacy determination.

Phase 1

Phase 1 provides for the application of criteria designed to partition tracts receiving bids into three general categories:



- those tracts receiving bids which MMS has identified as being nonprospective for commercial accumulations of hydrocarbons (nonviable),
- those where opportunities for strategic underbidding, information asymmetry, collusion, and other noncompetitive practices might most likely occur and where the Government has the most detailed and reliable data; and
- those where the competitive market forces can be relied upon to assure fair market value.

Based on these categories, the following three Phase 1 criteria are applied to all tracts receiving bids:

1. High bids on all tracts classified by MMS as being either development or drainage will be referred directly for further evaluation in Phase 2.
2. All legal high bids for tracts judged by MMS not to be located on a viable prospect will be accepted.
3. After screening for anomalous bids,1/ all legal high bids will be accepted for wildcat and proven tracts receiving three or more bids and more than the average number of bids for viable wildcat and proven tracts receiving one or two adjusted bids and all wildcat and proven tracts receiving three or more adjusted bids, i.e., whichever is more.

After applying the Phase 1 criteria for bid acceptance, the Regional Director, if he should determine that an unusual bidding pattern exists and affects tracts which would be accepted by the Phase 1 criteria, and if the unusual bidding pattern can be documented, has the discretionary authority, after consultation and coordination with the Solicitor, to pass those tracts so identified to Phase 2 for further analysis.

Phase 1 is conducted tract-by-tract and is generally completed within 3 days of the bid opening.

Phase 2

Phase 2 provides for the application of criteria designed to further determine bid adequacy on a tract-specific basis. All prospective wildcat and proven tracts whose high bids are not accepted in Phase 1 are passed to Phase 2 for further evaluation. After further mapping and/or analysis are completed in Phase 2, the viability determinations of these tracts can be reviewed, using the same procedures to determine viability that were applied in Phase 1.

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1/Anomalous bids will not be included in the adjusted bid number in either Phase 1 or Phase 2. Anomalous bids include all but the highest bid submitted for a tract by the same company (bidding alone or jointly) and the lowest bid on a tract when it is less than one-eighth of the next lowest bid. The "one-eighth rule" can exclude no more than one bid for a given tract.

Those wildcat and proven tracts which are subsequently determined to be nonviable can be eliminated from the set of tracts undergoing a full-scale MONTCAR run and the high bids on them accepted. All of the remaining tracts, including all drainage and development tracts, receive further evaluation by comparing the high bids with the Government's analysis of mean range of values (MROV) and the Discounted Mean Range of Values (DMROV). All tracts in Phase 2 which received three or more adjusted bids and wildcat and proven tracts which received two adjusted bids will be compared to the Geometric Average Evaluation of the Tract (GAEOT). In addition, if in the judgment of the Regional Director a tract is or may be subject to drainage, the relevant costs due to delays associated with bid rejection are considered in the bid adequacy determination. While it is expected that most evaluations would be undertaken based upon geological and geophysical data and analyses available at the time of the sale, additional analyses can be undertaken postsale at the discretion of the Regional Director.

The bid adequacy recommendations developed in Phase 2 are normally completed sequentially over a period ranging between 3 and 60 days after the sale. The Regional Director has the discretionary authority to extend this period up to 90 days after the sale when necessary to assure a thorough evaluation.

Statistics on the use of these procedures in OCS lease sales (April 1983 through April 1986) indicate that 51 percent of the tracts receiving bids (67 percent of the high bids) were accepted using Phase 1 criteria, and 49 percent were passed to Phase 2 for further evaluation. In the 1985-1986 period 67 to 72 percent of the tracts receiving bids were passed to Phase 2 for further evaluation; 28 to 33 percent were accepted by Phase I criteria reflecting both changes in the lease market and modifications in the use of the procedures. Seven percent of the total tracts receiving bids or 14.6 percent of the tracts passed to Phase 2 for further evaluation were rejected.

Table 1 contains statistics on the use of the two-phase bid adequacy procedures since they were adopted in 1983. In the 1983-1986 time period, 3,531 tracts received bids in areawide lease sales; 1,797 of these tracts were leased using Phase 1 criteria; 1,734 tracts were passed to Phase 2 for further evaluation. Two hundred and fifty three tracts with high bids totaling $505 million were rejected because the bids were determined to be inadequate. Two tracts were reneged on with high bids of $3.725 million. The 3,278 tracts leased yielded a return of $10.7 billion in bonuses for the lands leased and the rights conveyed. Included in this total are the high bids for 52 tracts in Sale 94 subject to Military Stipulation 5.

Minimum Bid Requirements

As part of the last 5-year program decision on fair market value, the Department increased the minimum bid from $25 to $150 per acre. In conjunction with the two-phase procedures, the minimum bid may help to assure fair market value by substantially increasing the bonus amounts bid on many one-bid tracts. The minimum bid represents an across-the-board Government evaluation standard with which all OCS high bids are compared--it provides the initial step in the overall bid adequacy process.



TABLE 1

Fair Market Value Procedures Statistics (1 of 3)

| Lease Offering | Mid-Atlantic (April 1983) Number of Tracts | Mid-Atlantic (April 1983) High Bids (000) | Central GUM (May 1983) Number of Tracts | Central GUM (May 1983) High Bids (000) | So.-Atlantic (July 1983) Number of Tracts | So.-Atlantic (July 1983) High Bids (000) | Western GOM (August 1983) Number of Tracts | Western GOM (August 1983) High Bids (000) | California Sale 73 Number of Tracts | California Sale 73 High Bids (000) | Eastern GOM (January 1984) Number of Tracts | Eastern GOM (January 1984) High Bids (000) | Subtotal Number of Tracts | Subtotal High Bids (000) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total of Tracts Receiving Bids | 40 | $71,141 | 656 | $ 3,469,215 | 11 | $13,362 | 436 | $1,549,262 | 8 | $16,022 | 156 | $310,586 | 1,307 | $5,429,588 |
| Phase 1 | | | | | | | | | | | | | | |
| Tracts Accepted By | | | | | | | | | | | | | | |
| Criterion 1 | 3 | $ 3,620 | 245 | $ 943,020 | 4 | $ 4,060 | 138 | $392,633 | 2 | $ 1,930 | 70 | $112,817 | 462 | $1,458,080 |
| Criterion 2-only | 2 | 4,510 | 73 | 936,082 | 0 | 0 | 55 | 358,647 | 1 | 3,131 | 13 | 100,171 | 144 | 1,402,541 |
| Criterion 3 (unduplicated) | 17 | 44,459 | 127 | 1,094,246 | 3 | 5,171 | 95 | 514,244 | - | - | 31 | 56,114 | 273 | 1,714,234 |
| Criteria 2 & 3 | 19 | 48,969 | 200 | 2,030,328 | 3 | 5,171 | 150 | 872,891 | 1 | 3,131 | 44 | 156,285 | 417 | 3,116,775 |
| Subtotal (a) | 22 | 52,589 | 445 | 2,973,348 | 7 | 9,231 | 288 | 1,265,524 | 3 | 5,061 | 114 | 269,102 | 879 | 4,574,855 |
| Percent of Total(%) | 55 | 74 | 68 | 86 | 64 | 69 | 66 | 82 | 38 | 32 | 73 | 87 | 67 | 73 |
| Tracts Passed to Phase 2 | | | | | | | | | | | | | | |
| Drainage or Dev. | 0 | $ 0 | 53 | $ 272,587 | 0 | $ 0 | 33 | $ 135,162 | 4 | $ 9,854 | 0 | $ 0 | 90 | $417,603 |
| Remaining Viable Tracts in Ph. 1 | 18 | 18,552 | 158 | 223,280 | 4 | 4,131 | 115 | 148,577 | 1 | 1,108 | 42 | 41,484 | 338 | 437,132 |
| Subtotal | 18 | 18,552 | 211 | 495,867 | 4 | 4,131 | 148 | 283,739 | 5 | 10,962 | 42 | 41,484 | 428 | 854,735 |
| Percent of Total(%) | 45 | 26 | 32 | 14 | 36 | 31 | 34 | 12 | 63 | 68 | 27 | 13 | 33 | 14 |
| Phase 2 | | | | | | | | | | | | | | |
| Tracts Evaluated | 18 | $18,552 | 211 | $ 495,867 | 4 | $ 4,131 | 148 | $ 283,739 | 5 | $10,962 | 42 | $ 41,484 | 428 | $854,735 |
| Accepted | 15 | 15,821 | 178 | 394,258 | 4 | 4,131 | 120* | 239,169* | 5 | 10,962 | 42 | 41,484 | 364 | 705,825 |
| Rejected | 3 | 2,731 | 33 | 101,609 | 0 | 0 | 28 | 44,570 | 0 | 0 | 0 | 0 | 64 | 148,910 |
| Rejected as Percent of Total (%) | 8 | 4 | 5 | 3 | 0 | 0 | 6 | 2 | 0 | 0 | 0 | 0 | 5 | 2 |

* The lessee refused to accept two tracts which received high bids of $3,725,000.
Criterion 1 is the non-viable prospect rule.
Criterion 2 is the number of bids rule.
Criterion 3 is the median of the geometric average rule.

TABLE 1

Fair Market Value Procedure Statistics (2 of 3)

| Lease Offering | Sale 83 Navarin (April 1984) Number of Tracts | Sale 83 High Bids (000) | Sale 81 Central GOM (April 1984) Number of Tracts | Sale 81 High Bids (000) | Sale 84 Western GOM (July 1984) Number of Tracts | Sale 84 High Bids (000) | Sale 87 Diapir (August 1984) Number of Tracts | Sale 87 High Bids (000) | Subtotal Number of Tracts | Subtotal High Bids (000) |
|---|---|---|---|---|---|---|---|---|---|---|
| Total of Tracts Receiving Bids | 186 | $631,228 | 529 | $1,446,585 | 402 | $945,717 | 232 | $877,131 | 1,349 | $3,900,661 |
| **Phase 1** | | | | | | | | | | |
| Tracts Accepted By | | | | | | | | | | |
| Criterion 1 | 68 | $204,025 | 155 | $319,586 | 91 | $175,251 | 179 | $524,003 | 493 | $1,222,865 |
| Criterion 2 only | 51 | 323,777 | 45 | 295,392 | 32 | 134,594 | 33 | 315,029 | 161 | 1,068,792 |
| Criterion 3 (unduplicated) | 21 | 54,961 | 128 | 450,597 | 115 | 389,480 | 3 | 12,188 | 267 | 907,226 |
| Criteria 2 & 3 | 72 | 377,738 | 173 | 745,989 | 147 | 524,074 | 36 | 327,217 | 428 | 1,975,018 |
| Subtotal (a) | 119 | 528,203 | 200 | 614,978 | 238 | 699,327 | 212 | 839,033 | 769 | 2,681,541 |
| Percent of Total(%) | 64 | 84 | 38 | 42 | 59 | 74 | 91 | 96 | 57 | 69 |
| Tracts Passed to Phase 2 | | | | | | | | | | |
| Drainage or Dev. | 0 | $ 0 | 40 | $46,432 | 35 | $10,209 | 1 | $5,167 | 76 | $ 61,808 |
| Remaining Viable Tracts in Ph. 1 | 67 | $103,625 | 289 | 785,174 | 129 | 236,181 | 19 | 32,931 | 504 | $1,157,911 |
| Subtotal | 67 | 103,625 | 329 | 831,606 | 164 | 246,390 | 20 | 38,098 | 580 | 1,219,719 |
| Percent of Total(%) | 36 | 16 | 62 | 58 | 41 | 26 | 9 | 4 | 43 | 31 |
| **Phase 2** | | | | | | | | | | |
| Tracts Evaluated | 67 | $103,625 | 329 | $831,606 | 279 | $635,871 | 20 | $38,098 | 695 | 1,609,200 |
| Accepted | 61 | 96,888 | 253 | 708,058 | 238 | 535,004 | 19 | 32,931 | 571 | 1,372,881 |
| Rejected | 6 | 6,737 | 76 | 123,548 | 41 | 100,867 | 1 | 5,167 | 93 | 236,319 |
| Rejected as Percent of Total (%) | 3 | 1 | 14 | 8 | 10 | 11 | 0 | 1 | 7 | 6 |



TABLE 1

Fair Market Value Procedures Statistics (3 of 3)

| Lease Offering | Sale 80 California (October 1984) Number of Tracts | Sale 80 High Bids (000) | Sale 98 Central GOM (April 1985) Number of Tracts | Sale 98 High Bids (000) | Sale 102 Western GOM (August 1985) Number of Tracts | Sale 102 High Bids (000) | Sale 94 Eastern GOM (December 1985) Number of Tracts | Sale 94 High Bids (000) | Sale 104 Central GOM (April 1986) Number of Tracts | Sale 104 High Bids (000) | Subtotal Number of Tracts | Subtotal High Bids (000) | Total Number of Tracts | Total High Bids (000) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total of Tracts Receiving Bids | 25 | $66,231 | 444 | $ 1,147,434 | 210 | $391,138 | 82* | $124,022** | 114 | $146,368 | 875 | $1,875,193 | 3,531 | $11,205,442 |
| **Phase 1** | | | | | | | | | | | | | | |
| Tracts Accepted By | | | | | | | | | | | | | | |
| Criterion 1 | 7 | $ 7,644 | 103 | $ 167,879 | 48 | $ 69,206 | 18 | $ 24,288 | 37 | $47,080 | 213 | $ 316,097 | 1,168 | $2,997,043 |
| Criterion 2 only | 2 | 10,995 | 29 | 211,119 | 11 | 46,949 | 9 | 28,183 | 0 | 0 | 51 | 297,246 | 356 | 2,768,379 |
| Criterion 3 (unduplicated) | | | | | | | | | | | | | | |
| Criteria 2 & 3 | | | | | | | | | | | | | | |
| Subtotal (a) | 9 | 18,639 | 132 | 378,998 | 59 | 116,155 | 27 | 52,471 | 37 | 47,080 | 264 | 613,343 | 1,524 | 5,765,422 |
| Percent of Total(%) | 36 | 28 | 30 | 33 | 28 | 30 | 33 | 42 | 32 | 32 | 30 | 33 | 43 | 51 |
| Tracts Passed to Phase 2 | | | | | | | | | | | | | | |
| Drainage or Dev. | 3 | $23,709 | 48 | $ 126,058 | 21 | $ 86,163 | 0 | $ 0 | 23 | $28,181 | 95 | $ 264,111 | 261 | $ 743,522 |
| Remaining Viable Tracts in Ph. 1 | 13 | 23,884 | 264 | 642,378 | 130 | 188,820 | 55 | 71,551 | 54 | 71,107 | 516 | 997,740 | 1,473 | 2,982,264 |
| Subtotal | 16 | 47,593 | 312 | 768,436 | 151 | 274,983 | 55 | 71,551 | 77 | 99,288 | 611 | 1,261,851 | 1,734 | 3,725,786 |
| Percent of Total(%) | 64 | 72 | 70 | 67 | 72 | 70 | 67 | 58 | 68 | 68 | 70 | 67 | 49 | 33 |
| **Phase 2** | | | | | | | | | | | | | | |
| Tracts Evaluated | 16 | $47,593 | 312 | $ 768,436 | 151 | $274,983 | 55 | $ 71,551 | 77 | $99,288 | 611 | $1,261,851 | 1,734 | $3,725,786 |
| Accepted | 14 | 43,483 | 277 | 700,379 | 136 | 243,021 | 55 | 71,551 | 64 | 83,197 | 546 | 1,141,631 | 1,481 | 3,220,337 |
| Rejected | 2 | 4,110 | 35 | 68,057 | 15 | 31,962 | 0 | 0 | 13 | 16,091 | 65 | 120,220 | 253 | 505,449 |
| Rejected as Percent of Total (%) | 8 | 6 | 8 | 6 | 7 | 8 | 0 | 0 | 11 | 11 | 7 | 6 | 7 | 5 |

* These are 52 tracts subject to military stipulation 5. As of February 1986, 30 leases had actually been issued. Adjustments will be made as they occur.

** This figure represents the high bids on all 82 tracts. As of February 1986, bonus receipts equalled $52,426 million. (1/5 bonus subject to military stipulation 5 plus total bonuses for 30 tracts leased). For bid acceptance purposes, no high bids were rejected.

Criterion 1 is the non-viable prospect rule.
Criterion 2 is the number of bids rule.
Criterion 3 is the median of the geometric average rule.

The analytical basis for the change was an empirical and theoretical study which focused on the effects of a higher minimum bid on bidding behavior and Government receipts for medium-sized sales which were scheduled for 1982. (Marshall Rose, Minimum Dollar Bid Requirements for Moderately-Sized OCS Lease Sales: The Case of 1982 Offerings, U.S. Department of the Interior, Office of Policy Analysis (OPA), December 1981.) A bidding model was developed and originally applied to 1,689 tracts offered for lease between 1978 and 1980. The findings were then extended to tracts scheduled to be offered in 1982 sales to determine the Government revenue effects (focused on one- and two-bid tracts). The quantitative results indicated that increasing the minimum bid amount from $25 to approximately $150 per acre would enhance the expected present value of Government receipts from those sales. The increase in Government receipts was estimated to be in the range of $35 to $50 million per 1,000 tracts leasable in 1982 at a minimum bid of $25 per acre. The results of the analysis also indicated that increasing the minimum bid to $150 per acre would generally not significantly affect competition and the number of tracts receiving bids. It was estimated that the reduction in the number of tracts receiving bids would be only 16 percent for one-bid tracts and 10 percent for two-bid tracts that would ordinarily receive a bid when the minimum was set at $25 per acre.

Figure 1 graphically illustrates the results of the analysis of the estimated effect of increased minimum bids on aggregate Government receipts for one-bidder tracts in 1982 sales. The minimum bid amounts charted are: $0.5 million (equivalent to $86 per acre); $1.0 million (equivalent to $172 per acre); and $2.0 million (equivalent to $344 per acre). The aggregate effect on Government receipts took into consideration the number of tracts not sold in 1982 and the resulting cost of delay, and the higher bids on tracts sold in 1982. The graph illustrates that as the minimum bid is increased to $172 per acre, there was estimated to be a positive incremental effect on Government receipts; beyond that amount, the effect on Government receipts was estimated to decrease.

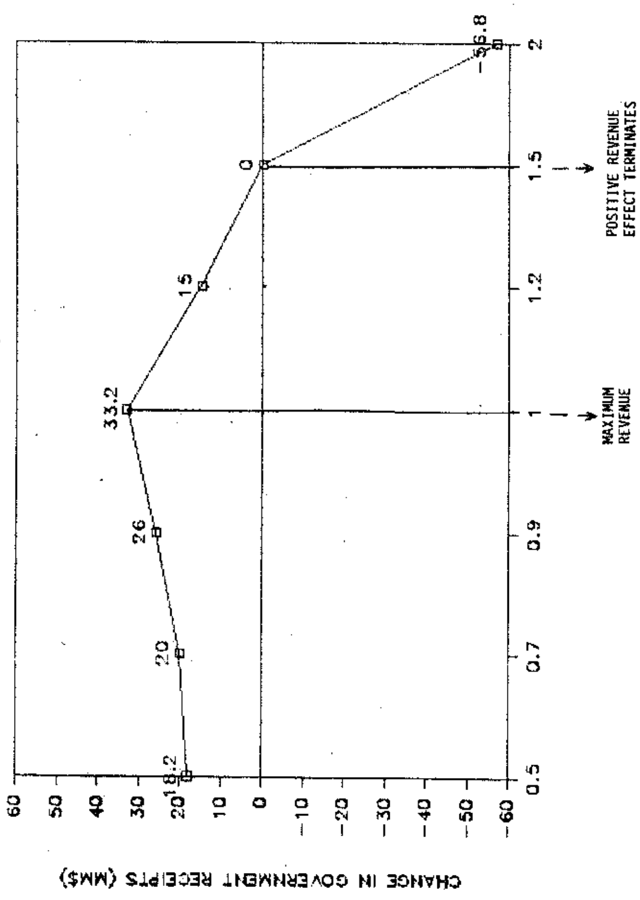
Recently, MMS analyzed empirical bidding data for 19 OCS lease sales, held offshore Alaska and in the Gulf of Mexico (GOM), to assess the effects of the change of the minimum bid policy on the level of bidding interest.

The analysis found that the effects predicted in the OPA analysis appeared to be largely confirmed in practice, namely that raising the minimum would increase the high bids on the vast majority of affected tracts up to the new minimum. The most striking finding was that in the five GOM sales held prior to the policy change, only 4 percent of the high bids were between $150 to $200 per acre, while only 8 percent of the high bids fell between $150 to $300 per acre. In the four GOM sales held immediately following the policy change, 24 percent of the high bids fell in the $150 to $200 per acre range, while 46 percent of the high bids were between $150 to $300 per acre. (See Tables 1 and 2.) The Alaskan sales showed a similar pattern. Using the



FIGURE 1

Effects on Net Present Value of Federal Budget Receipts ($Millions) from Application of Minimum Bid Amount Requirements in 1982 on Tracts Receiving One Bid




MINIMUM BID: MILLIONS OF DOLLARS/TRACT

Source: Estimates derived from: Marshall Rose, Minimum Dollar Bid Requirements for Moderately Sized OCS Lease Sales: The Case of 1982 Offerings, U.S. Department of the Interior, Office of Policy Analysis, December 1981.

**TABLE 1**

**Distribution of High Bids for Gulf of Mexico Offerings Using $25/Acre Minimum Bid for Bonus Bid, Fixed Royalty Tracts**

| Offering Date | Total No. High Bids | Percent of Number of All High Bids: $25-$150/Acre | $150-$200/Acre | $200-$300/Acre | $300+/Acre |
|---|---|---|---|---|---|
| 9/30/80 C&E Gulf A-62 | 77 | 5 | -- | 1 | 94 |
| 11/18/80 W. Gulf 62 | 44 | 5 | -- | 5 | 91 |
| 7/21/81 C&W Gulf A-66 | 144 | 8 | 4 | 6 | 82 |
| 10/20/81 C&E Gulf 66 | 59 | 8 | 2 | 3 | 86 |
| 2/9/82 C&W Gulf 67 | 127 | 24 | 6 | 5 | 65 |
| Total | 451 | 11 | 4 | 4 | 81 |

**TABLE 2**

**Distribution of High Bids for Gulf of Mexico Offerings Using $150/Acre Minimum Bid for Bonus Bid, Fixed Royalty Tracts**

| Offering Date | Total No. High Bids | Percent of Number of All High Bids: $25-$150/Acre | $150-$200/Acre | $200-$300/Acre | $300+/Acre |
|---|---|---|---|---|---|
| 11/17/82 C&W Gulf 69 I | 64 | -- | 22 | 12 | 66 |
| 3/8/83 C&E Gulf 69 II | 13 | -- | 31 | 15 | 54 |
| 5/25/83 C. Gulf 72 | 635 | -- | 20 | 17 | 62 |
| 8/24/83 W. Gulf 74 | 432 | -- | 22 | 22 | 56 |
| 1/5/84 E. Gulf 79 | 156 | -- | 49 | 27 | 24 |
| 4/24/84 C. Gulf 81 | 529 | -- | 24 | 29 | 47 |
| 7/18/84 84 | 402 | -- | 31 | 25 | 44 |
| Total | 2231 | -- | 25 | 20 | 53 |



**TABLE 3**

**Distribution of High Bids for Alaska Offerings Using $25/Acre Minimum Bid for Bonus Bid, Fixed Royalty Tracts**

| Offering Date | Total No. High Bids | Percent of Number of All High Bids: $25-$150/Acre | $150-$200/Acre | $200-$300/Acre | $300+/Acre |
|---|---|---|---|---|---|
| 12/11/79 Diapir Fld. BF | 25 | 24 | -- | 8 | 68 |
| 10/21/80 Gulf of Alaska 55 | 16 | 63 | -- | 6 | 31 |
| 9/29/81 Cook Inlet 60 | 6 | 83 | -- | -- | 17 |
| Total | 47 | 45 | -- | 6 | 49 |

**TABLE 4**

**Distribution of High Bids for Alaska Offerings Using $150/Acre Minimum Bid fpr Bonus Bid, Fixed Royalty Tracts**

| Offering Date | Total No. High Bids | Percent of Number of All High Bids: $25-$150/Acre | $150-$200/Acre | $200-$300/Acre | $300+/Acre |
|---|---|---|---|---|---|
| 10/13/82 Diapir Fld. 71 | 108 | -- | 19 | 22 | 58 |
| 3/15/83 Norton Basin 57 | 54 | -- | 43 | 13 | 44 |
| 4/12/83 St. Geo. Basin 70 | 82 | -- | 23 | 20 | 57 |
| 4/17/84 Sale 83 Navarin | 186 | -- | 37 | 22 | 41 |
| Total | 430 | -- | 30 | 20 | 50 |

$25 per acre minimum, Alaskan sales held prior to the policy change had no high bids in the $150 to $200 per acre interval. After the policy change to a $150 minimum bid, 30 percent of all high bids fell in the $150 to $200 per acre interval. (See Tables 3 and 4.) The decline in the percentage of bids offered in the $300+ per acre range is indicative of the decreasing quality, lower prices, and increased cost/risk associated with the tracts being offered. However, it is not likely that this could fully explain the revised distribution of bids, wherein 30 percent of the tracts received bids within $50 per acre of the revised minimum bid of $150 per acre.

Drawing upon the earlier OPA study, further analysis was conducted to estimate the average and total bid amounts which would have been received with a $25 acre minimum and compared the results to empirical bidding data for six OCS lease sales beginning with the first areawide lease sale in the GOM. Figure 2 graphically illustrates for each of the six sales the actual aggregate bonus bids at $150 per acre and the estimated aggregate bonus bids at $25 per acre and $300 per acre. In these sales, the higher minimum bid of $150 per acre was estimated to have increased aggregate bonuses by as little as $50 million and as much as $84 million per sale. The total aggregate bonus increase was $415 million. The bidding results in Sale 79 (Eastern GOM) and Sale 83 (Navarin) did not substantiate earlier concerns that the higher minimum bid might preclude bidding interest in these high-risk and/or high-cost areas.

Additional analysis of the same six sales was conducted to estimate the retrospective revenue effects of a $300 per acre minimum compared to the $150 per acre minimum. The actual bid data from the sales were modified to incorporate assumptions inferred from the previously cited OPA study that such a change would preclude about 75 percent of the high bids observed below $200 per acre and 25 percent of those received between $200 to $300 per acre. The remaining high bids would be raised to the revised minimum bid. The effect of raising the minimum bid from $150 per acre to $300 per acre was estimated to be a decline of about 5 percent in the aggregate high bids received per sale (See Figure 2).

The original study focused on Gulf of Mexico leases under tract selection sales when oil was selling at $30 per barrel, so its applicability in today's environment may be limited.

In conjunction with the development of the net economic value estimates for this 5-year program the minimum bid also has been analyzed and identified as a sale-planning area specific policy tool which could be used to encourage efficient exploration and development. Appendix F presents the conceptual basis for using the minimum bid to accomplish these objectives.

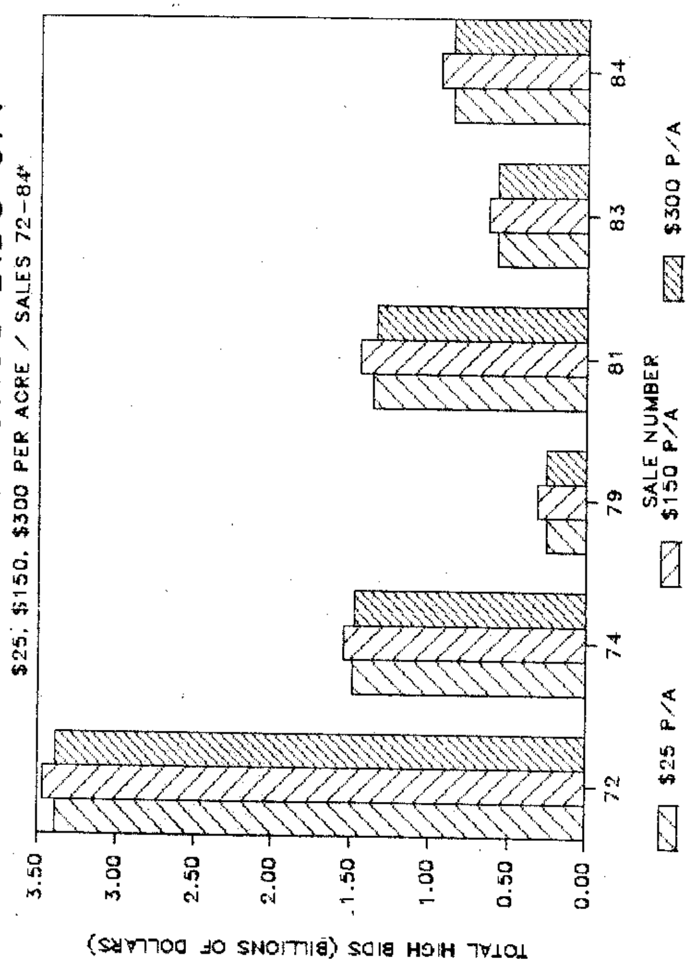
Alternative bidding systems have currently not been addressed in terms of their effects on competition and fair market value. Based on past analysis of these systems the Department has found that the effects on competition have been negligible. (See: DOI, MMS: "Report to Congress on Fiscal Year 1983 Outer Continental Shelf Lease Sales and Evaluation of Alternative Bidding Systems", April 1983).



FIGURE 2

AGGREGATE BONUS BIDS OF:

$25, $150, $300 PER ACRE / SALES 72-84*




*The $150 per acre bonuses are actual bonuses received; $25 and $300 per acre aggregate bonuses are estimated.

## VI. Conclusions

An objective of the offshore leasing program is to increase the contribution to national income from leasing activities, including exploration, development, and production. It takes into consideration existent and projected market conditions affecting OCS oil and gas leasing rates. The Secretary's continuing assessment of the OCS lease market and the resultant policies and procedures developed for considering bid adequacy are also the measures used to assure the receipt of fair market value. These policies and procedures are not static and change in response to an assessment of the market conditions over time. The description of bid adequacy procedures in section V reflects an understanding of the lease market and procedures necessary to assure that fair market value is being received.

The Secretary, in formulating an OCS leasing schedule is also required to consider and balance other factors which are important to the Nation in the management of the resources of the OCS. Included are national security benefits, environmental costs and benefits, equitable sharing among regions, Government receipts, etc. Many of these factors cannot easily or necessarily be quantified but must be considered in the formulation of an oil and gas leasing program.

It is worth noting that the Secretary is not required to maximize any one of these elements, such as Government receipts. The U.S. Court of Appeals for the District of Columbia in its decision on the 5-year leasing program in July 1983 states:

> Section 18(a)(4)'s requirement that the program assure receipt of fair market value does not mandate the maximization of revenues, it only requires receipt of a fair return.

The court thus distinguished between meeting the legal requirement and the broader policy question about distribution of benefits between lessees and the Government.

# APPENDIX L

## STEPS IN OFFSHORE LEASING FOR STANDARD SALES

## STEPS IN OFFSHORE LEASING FOR STANDARD SALES

### EARLY COORDINATION

Before the preparation of the Call for Information and Nominations, various contacts are made by Minerals Management Service (MMS) officials with the governments of affected coastal States. These contacts are tailored for each sale and can include the following: a letter to the Governor of each affected State announcing the commencement of the planning process, including a description of the steps in the prelease process with an indication of points at which the Governor's comments will be solicited, a commitment to provide specific time and locations of scoping meetings and draft environmental impact statement (EIS) hearings as soon as possible, and a copy of the most recent planning schedule; letters or phone calls to appropriate State members of the OCS Advisory Board Policy Committee and the Regional Technical Working Group (RTWG); and discussions concerning the potential Call area.

### IDENTIFY AREA OF HYDROCARBON POTENTIAL

About two months before the Call for Information and Nominations is published, the MMS determines the area of hydrocarbon potential for the upcoming sale. This is the area considered by MMS to have potential for the discovery of oil and gas.

### CALL FOR INFORMATION AND NOMINATIONS; NOTICE OF INTENT TO PREPARE AN EIS

The Call, approved by the Assistant Secretary--Land and Minerals Management (ASLM), is published in the Federal Register. The Call invites potential bidders to nominate areas and indicate levels of interest in leasing. The Call also solicits comments from States and all interested parties on any environmental effects and use conflicts as well as coastal zone consistency concerns. States and others have the opportunity to comment on areas or topics of concern that should be considered in planning the lease sale. Comments are normally due 45 days after the Call is published. At the time the Call is published, consultation is begun concerning possible multiple use conflicts with Department of Defense (DOD) and other activities in the sale area. Also, information is provided to affected States under section 8(g) of the OCS Lands Act.



A Notice of Intent to prepare an EIS is also published. It announces the initiation of EIS scoping and invites public assistance in determining the significant issues, including coastal zone consistency issues, and alternatives to be analyzed in the EIS on the lease sale.

The Call and Notice of Intent are sent to the Governor of each affected State by the Regional Director with a letter which invites comments on the Call. In the letter, the Governor is asked to identify issues and areas of concern which should be considered in the development of the initial leasing proposal. The Regional Director's letter also indicates interest in meeting with representatives of the State to discuss the State's comments on the Call. Possible mitigating measures to accommodate concerns may be identified at this step. Conflicts which may arise during State consistency concurrence review of plans of exploration and development and production (per section 307(c)(3) of the Coastal Zone Management Act [CZMA]) may also be identified at this meeting.

### AREA IDENTIFICATION

About 4 months after the Call is published, the analysis of nominations and comments is completed. The Director, MMS, recommends the identification of an area where leasing is to be studied as the proposed Federal action in an EIS. When the ASLM approves this proposal it becomes the Area Identification. Areas may be deleted at this stage from further study where significant multiple use conflicts exist and the potential for hydrocarbon discovery is low. After any area identification is made, the MMS provides the affected States with more detailed information concerning section 8(g) blocks if appropriate. Consultation with a State over potential section 7 boundary issues may be initiated if appropriate.

Following the announcement of Area Identification the Regional Director provides the Governor with an explanation of what was done with the State's comments--how the comments were employed in the Area Identification process and how they will be employed in the development of alternatives and mitigating measures to be analyzed in the EIS.

In addition to providing the Governor of each affected State with an explanation of how his recommendations were used in the decision process on Area Identification and how they will be used elsewhere in the prelease process, the letter invites additional comments from the State for use in the development of the EIS. These comments are incorporated into the scoping process. (Scoping meetings to further define issues and receive comments relating to the proposed sale and EIS may occur before and after Area Identification).

## DRAFT ENVIRONMENTAL IMPACT STATEMENT

About one year after the Call is published, a draft EIS is issued which describes the entire planning area and focuses on the potential environmental effects of oil and gas activities in the area proposed for leasing. The EIS includes evaluation of possible future CZMA conflicts concerning section 307(c)(3). For sales in the Alaska Region, the EIS also evaluates the effects on subsistence uses that could occur from leasing, exploration, and development/production of OCS oil and gas, as required by court cases interpreting section 810 of the Alaska National Interest Lands Conservation Act (ANILCA). The document also analyzes alternatives to the proposed action. The availability of the draft EIS is announced in the Federal Register.

## PUBLIC COMMENT PERIOD

A 60-day comment period follows public availability of the draft EIS, during which time public hearings are held in the affected region. Comments received either at public hearings or in writing are considered in preparation of the final EIS.

Public hearings on the draft EIS are announced by means of a letter from the MMS Regional Director to the Governor of each affected State as well as by Federal Register Notice. Copies of the letter to the Governor of each affected State are sent to the appropriate Policy Committee and RTWG members.



The MMS Regional Director transmits the draft EIS to the Governor of each affected State and solicits comments on the EIS as well as substantive comments on the proposal. The MMS transmittal letter also invites the State to request a meeting with MMS to discuss State comments. Copies of the letter to the Governor are provided to the appropriate Policy Committee and RTWG members.

## FINAL ENVIRONMENTAL IMPACT STATEMENT; PROPOSED NOTICE OF SALE

The final EIS is prepared, which considers and assesses comments received during the draft EIS public comment period. These include further State and local comments on coastal zone consistency matters and, for Alaska sales, subsistence uses. When final, the EIS is filed with the Environmental Protection Agency. A Secretarial Issue Document (SID) is prepared to analyze all issues involved in the proposed sale, again including possible coastal zone consistency conflicts that could be expected at the exploration and development stages. By this time in the leasing process, the MMS and other Federal agencies have usually reached agreement on mitigating measures and deferrals to assure compatible mutual use of a sale area. The proposed Notice, signed by the ASLM, and contains the proposed terms and conditions of the sale. Blocks proposed for leasing, stipulations, and other mitigating measures are listed, along with proposed bidding systems and lease terms.

As required by section 19 of the OCS Lands Act, the proposed Notice is sent to Governors of affected States with a letter requesting comments on size, timing, or location of the sale. This letter also explains how State coastal zone management program policies have been considered in decisionmaking and invites any further comment the State wishes to make. A copy of this letter is sent to the States' official contact in the coastal zone management agency and to the appropriate Policy Committee members. If there is a litigated Federal/State jurisdictional dispute involving blocks proposed for leasing in a sale, an agreement offer is made to the State at this time under section 7 of the OCS Lands Act.

| | |
|---|---|
| SUPPLEMENTAL NOTICES | Supplemental Notices highlighting specific questions on a proposed sale may also be published for public response at various points in the presale process. |
| GOVERNORS' COMMENTS | The Governors of affected States have 60 days in which to comment on size, timing, or location of the sale. These comments are used to develop recommendations to the Secretary regarding the final Notice. |
| FINAL NOTICE OF SALE | After comments on the proposed Notice are received from the Governors, a final decision memorandum which analyzes all issues is prepared for the Secretary. Section 19 of the OCS Lands Act provides that the Secretary is to accept recommendations of a Governor if the Secretary determines that they provide for a reasonable balance between the national interest and the well being of the affected State. The rationale for the Secretary's determination is to be communicated to the Governor in writing. About 90 days after the proposed Notice is published and after consideration of comments from the Governors, the Secretary issues a final Notice of Sale, if he decides to proceed. The date, timing, location, blocks to be offered, terms, and conditions of the sale are published in the <u>Federal Register</u> not less than 30 days before the sale is conducted. |
| SALE | Not less than 30 days after the final Notice is published, a sale is conducted by the appropriate MMS regional office. A public opening and reading of sealed bids submitted by qualified bidders occurs. |
| BID ADEQUACY REVIEW | High bids for each block are evaluated after the sale to assure receipt of fair market value. The Justice Department and Federal Trade Commission also review the results to ensure that awarding leases does not create a situation inconsistent with antitrust laws. |
| LEASES ISSUED | The Secretary has up to 90 days after receipt of bids to either accept or reject a bid. Bid acceptance has been delegated to the MMS Regional Director Normally, bids are accepted and leases issued within 1-2 months after the sale. |

APPENDIX M

FEDERAL REGISTER NOTICES ON THE

DEVELOPMENT OF THE NEW 5-YEAR PROGRAM

Federal Register Notices on the Development of the New 5-Year Program

1. Request for Comments on the Proposed 5-year Outer Continental Shelf (OCS) Oil and Gas Leasing Program for 1987 through 1991 (51 FR 4816, February 7, 1986)

2. Request for Comments on Appendix P: Analysis of Tract Selection and Areawide Leasing Approaches (an Appendix to the Secretarial Issue Document for the upcoming Proposed 5-Year Outer Continental Shelf (OCS) Oil and Gas Leasing Program) (50 FR 33418, August 19, 1985).

3. Extension of Period of Confidentiality for Privileged or Proprietary Data Submitted in Response to the Request for Comments on the Draft Proposed 5-Year Outer Continental Shelf (OCS) Oil and Gas Leasing Program for Mid-1986 through Mid-1991 (50 FR 20140, May 14, 1985).

4. Request for Comments on the Draft Proposed 5-Year Outer Continental Shelf (OCS) Oil and Gas Leasing Program for Mid-1986 through Mid-1991 (50 FR 11565, March 22, 1985).

5. 5-Year Outer Continental Shelf Oil and Gas Leasing Program; Development and Request for Comments (49 FR 28332, July 11, 1984).



4816 Federal Register / Vol. 51, No. 26 / Friday, February 7, 1986 / Notices

**Minerals Management Service**

**Proposed 5-Year Outer Continental Shelf Oil and Gas Leasing Program for 1987 Through 1991**

**AGENCY:** Minerals Management Service, Interior.

**ACTION:** Request for comments on the proposed 5-Year Outer Continental Shelf (OCS) Oil and Gas Leasing Program for 1987 through 1991.

**SUMMARY:** The Secretary of the Interior is issuing for review and comment the Proposed 5-Year OCS Oil and Gas Leasing Program for 1987–1991. The Proposed Program is an intermediate stage in the development of the new 5-year program pursuant to section 18 of the OCS Lands Act, as amended, and consists of a proposed delineation of OCS planning areas, a proposed schedule of sales to be held during the period 1987–1991, and a selection of proposed leasing policies. The Proposed Program is described and analyzed in a Secretarial Issue Document and a draft Environmental Impact Statement (EIS)

A copy of this Notice and other documents explaining the Proposed Program are being sent to the Governors of affected coastal States, to the Congress, and to the heads of affected Federal Agencies.

The proposed Program for 1987–1991 proposes a number of changes to slow the pace and reduce the scope of leasing as compared with the current program: lengthening the period between sales in most areas from 2 to 3 years; and reducing the acreage to be offered for lease by adopting the approach of focusing on promising acreage. This approach incorporates the policy of emphasizing consultation with coastal States and other affected parties with a view to the early resolution of conflicts. In 21 of the 26 OCS planning areas, the Proposed Program schedules 27 standard sales, 10 frontier exploration sales, and 5 small supplemental sales. The Proposed Program has the flexibility to satisfy the statutory requirements to meet national energy needs under a variety of conditions. It responds to recent declines in hydrocarbon prices while at the same time retaining the ability to meet national energy needs under changing geopolitical or economic circumstances. In addition, the Proposed Program continues policies and procedures which assure the receipt of fair market value.

This Notice invites public comment on the Proposed Program. Responses to this Notice will be considered for the Secretarial decision on the adoption of a Proposed Final Program in late 1986/early 1987. After a 60-day congressional and Presidential notification period, the Secretary can give final approval to the new program.

**DATE:** Comments must be received by May 8, 1986.

**ADDRESSES:** Comments should be submitted to the Deputy Associate Director for Offshore Leasing, Minerals Management Service (MMS), Mail Stop 641, 18th & C Streets, NW., Washington, DC 20240. Hand deliveries to the Department of the Interior may be made to Room 2525 at that address. If any privileged or proprietary information which the respondent wishes to be treated as confidential is attached to comments, the envelope should be marked, "Contains Confidential Information".

**FOR FURTHER INFORMATION CONTACT:** Telephone contact may be made with Chris Oynes, Chief, Offshore Leasing Management Division, MMS, at (202) 343–6906 or Paul Stang, Chief, Branch of Program Development and Planning, MMS, at (202) 343–1072. Copies of descriptions of planning area boundaries, maps and block and acreage counts of subareas deferred from leasing, and maps of subareas highlighted for further analysis and comments can be obtained by calling Tim Redding at (202) 343–1072.

Author: Robert Samuels, Branch of Program Development and Planning, MMS.

**SUPPLEMENTARY INFORMATION:** The Proposed Program is the second of three preparatory versions of the new program prescribed by section 18 of the OCS Lands Act. Initiation of development of the first stage was announced in a July 11, 1984, request for comments published in the Federal Register (49 FR 28332). Completion of the first stage, the Draft Proposed Program, was announced in the Federal Register on March 22, 1985 (50 FR 11565). The consideration of public comments in response to those announcements was an important part of developing the Proposed Program.

Pursuant to section 18, the schedule and policies selected for the Proposed Program were based on a consideration of the factors specified by the act and provide "to the maximum extent practicable, a proper balance between the potential for environmental damage, the potential for the discovery of oil and gas, and the potential for adverse impact on the coastal zone." The Proposed Program is also designed to allow all parties to plan for OCS leasing activities while providing sufficient flexibility to meet national energy needs under changing circumstances affecting the price and supply of oil and gas.

The proposals which comprise the Proposed Program will be reviewed at two later program development stages: the Proposed Final Program, planned for late 1986/early 1987; and final approval, following appropriate consultation and a 60-day congressional and Presidential notification period.

The following explanatory items appear at the end of this Notice: Figure 1, which depicts the leasing schedule selected for the Proposed Program; and Maps 1 and 2, depicting the planning areas.

### 1. Planning Area Boundaries for the Proposed Program

The proposed configuration of OCS planning areas is depicted on Maps 1 and 2.

The configuration of several of those planning areas was further revised by the Secretary's decision to include in the Proposed Program a provision that would defer from leasing the following 15 portions of OCS planning areas ("subareas"): offshore California—the area offshore Pt. Reyes Wilderness, Pt. Reyes-Farallon Islands National Marine Sanctuary, the area offshore San Francisco Bay, the area in the immediate vicinity of Cordell Bank, the area offshore Monterey Bay, the area offshore Big Sur, the Santa Barbara Federal Ecological Preserve and Buffer Zone, Channel Islands National Marine Sanctuary, and the Coordinated Anti-Submarine Warfare Area (San Nicolas Basin); offshore Florida—Seagrass Beds, the Florida Middle Ground, and the Atlantic coast portion of the Straits of Florida planning area extending to 25°07′ N. latitude; offshore Georgia—Gray's Reef National Marine Sanctuary; offshore North Carolina—the U.S.S. Monitor National Marine Sanctuary and Buffer Zone; and offshore Texas—the Flower Garden Banks. Maps depicting these subareas will appear in the draft EIS. Separate copies of those maps and a list of block and acreage counts for those subareas can be obtained by calling the contact person indicated above.

In addition, the Secretary highlighted the following 13 subareas for further analysis and comments: three subareas extending 15 nautical miles offshore, in the North, South, and Mid-Atlantic planning areas; the Gulf of Maine; the National Aeronautics and Space Administration Flight Clearance Zone offshore Cape Canaveral (extending to 170 nautical miles offshore); a subarea extending between 20 and 30 nautical miles offshore the Florida Gulf Coast from Naples to Apalachicola; the subarea south of 26° N. latitude and east of 82° W. longitude in the "Miami" official protraction diagram offshore Florida in the Eastern Gulf of Mexico; the three subareas estimated by MMS to be beyond the area of hydrocarbon potential in the Washington-Oregon, Northern California, and Central California planning areas; two subareas totaling approximately 210 blocks adjacent to Unimak Pass, Alaska, in the St. George Basin and the North Aleutian Basin planning areas; and a subarea of approximately 59 blocks offshore Point Barrow, Alaska.

Maps depicting these subareas will appear in the draft EIS. Separate copies of those maps can be obtained by calling the contact person indicated above.

### 2. The Leasing Schedule for the Proposed Program

*a. General*

Over the 5-year period 1987–1991, the Proposed Program provides for 27 standard sales, 10 frontier exploration sales, and 5 small supplemental sales. These sales are scheduled in 21 of the 26 OCS planning areas. The Proposed Program schedules annual standard sales in the two highest-value, highest-interest areas, the Central and Western Gulf of Mexico. It proposes 27 standard or frontier exploration sales in 19 other areas, with approximately 3 years or longer between sales. The Proposed Program does not schedule any sales in Aleutian Arc, Aleutian Basin, Bowers Basin, St. Matthew-Hall, or the Straits of Florida. A question about whether a sale should be scheduled in the southern portion of the Straits of Florida planning area for the Proposed Final Program appears at the end of this Notice.

The basic determinants of the sale schedule depicted in Figure 1 are the pace of leasing decided upon by the Secretary, the date of the last sale held or scheduled in a planning area, and other administrative considerations. Thus, on the one hand, a single sale is scheduled for Norton Basin in 1989 because that is 3 years after the 1986 Norton Sale (Sale 100) and the 5-year period of the program ends before the subsequent 3-year cycle. On the other hand, two sales are scheduled in the Beaufort Sea (1987 and 1990) because the 3-year cycle starts with the 1984 Beaufort Sea Sale.

*b. Flexibility Provisions*

The Proposed Program contains three flexibility features: frontier exploration sales; supplemental sales; and the acceleration provision.

Frontier exploration sales are proposed for areas where incomplete geological data, MMS estimates of lower value, or current industry indications of lower interest call for an early decision point on whether to proceed with the standard presale process. For these sales, a Request for Interest soliciting industry interest in holding the sale will be published in the Federal Register approximately 4 months prior to the Call. Responses to that request, as well as the annual review of the program under section 18(e), will be used to help determine whether to proceed with the presale process. If interest is insufficient to justify proceeding with the sale, it can be delayed or cancelled. If delayed, a Request for Interest can then be reissued on a perennial or less frequent basis until interest is determined to be sufficient to hold the sale or the sale is cancelled. Ten frontier exploration sales are proposed: two in the North Atlantic and one in the Mid-Atlantic, the South Atlantic, Washington-Oregon, and the same five Alaska areas where such sales were scheduled in the Draft Proposed Program (Shumagin, Kodiak, Cook Inlet, Gulf of Alaska, and Hope Basin).

Supplemental sales on an annual basis are included in the Proposed Program for a small number of blocks in areas other than the Central and Western Gulf of Mexico in either of the following categories: blocks on which bids were rejected in the preceding year (i.e., the year preceding the one in which the supplemental sale is scheduled by the 5-year program); or drainage and development blocks.

The reoffering of rejected bid blocks would diminish the cost of delay of leasing blocks demonstrated to be of interest to industry. This provision would reintroduce the concept of drainage sales on a basis compatible with the requirements of the OCS Lands



Act Amendments of 1978 and similar to procedures of the State of Alaska (set forth in Alaska Statutes 38.05.180(d)). These blocks will only be offered after compliance with the requirements of the National Environmental Policy Act, the OCS Lands Act, and other applicable statutes. The environmental assessment documentation for each of these sales would be released prior to the proposed Notice of Sale. If it is determined that an EIS is required for one or more blocks to be offered in one of these sales, revised presale milestones would be issued.

The acceleration provision responds to the need to plan for an unknown future with limited information. Changes in the world energy market as well as exploration results in frontier areas can dramatically affect the demand for offshore leases. Thus, the 5-year program needs to have flexibility to adjust to major unforeseen developments. One means of providing such flexibility is the provision to permit the acceleration of leasing from triennial to biennial, if carefully defined criteria are met (but not so as to increase the total number of sales in any planning area in the approved program). The areas where such acceleration could be considered include: Southern California; Eastern Gulf of Mexico; Central California; Northern California; Navarin Basin; Beaufort Sea; North Aleutian Basin; and St. George Basin.

The question of whether to accelerate a sale in an area would be made on a sale-by-sale basis. Consideration of accelerating a particular sale would be initiated by any one of four criteria: (1) A finding by the Secretary that a new discovery in a planning area indicates that biennial leasing there is in the national interest; (2) activation of the International Energy Agency's oil sharing agreement; (3) drawdown of the Strategic Petroleum Reserve because of a severe oil supply disruption; or (4) a major disruption in Mideast oil shipments. Comments on possible economic criteria in particular are solicited at the end of this Notice.

The concept of acceleration, which was introduced in the Draft Proposed Program to provide flexibility, is still under development. Comments are requested on appropriate means of implementing acceleration, including criteria for considering it in a particular planning area. Such criteria would identify a necessary component of the decision for accelerating leasing. A decision by the Secretary that acceleration is appropriate would be based on close consultation with affected States and consideration of the Nation's energy needs, environmental factors—including the results of the Environmental Studies Programs, and multiple-use factors.

The purpose of including the acceleration provision in an approved leasing program is so that its exercise would be the implementation of part of the program approved pursuant to section 18 rather than a significant revision of it.

### 3. Size of Lease Sales

The proposed presale process, focusing on promising acreage, determines the size of lease sales. The Department uses an extensive consultation and balancing process to offer acreage where OCS leasing would be environmentally sound and has a potential to lead to exploration for oil and gas resources. In this process, the Department uses information and nominations obtained from affected States, local governments, Federal Agencies, the public, and potential bidders, as well as MMS analyses. Focusing on promising acreage aims at the resolution of conflicts early in the presale process by the achievement of consensus on key issues—especially concerning acreage with low MMS resource estimates and low industry interest.

Early steps in the presale process include the Call for Information and Nominations and the Area Identificaion. The Call depicts the area of hydrocarbon potential projected by MMS. The Call may be tailored on a case-by-case basis to exclude portions of the planning area (as in the exlusion of the Flower Garden Banks from the 1987 Western Gulf of Mexico Sale). In area Identification, responses to the Call are used in structuring the area to be analyzed in the EIS. In addition to these early steps, consultation also occurs at later steps in the presale process.

### 4. Assurance of Receipt of Fair Market Value in the Proposed Program

Section 18(a)(4) of the OCS Lands Act provides that leasing activities are to be conducted so as to assure receipt of fair market value for lands leased and rights conveyed. The Proposed Program maintains both the current procedures for assuring the receipt of fair market value and the current flexible policy for reconsidering the basic approach of $150/acre as the minimum bid on a sale-by-sale basis. The proposed program also provides for a review of the criteria to be used in that reconsideration of the minimum bid level.

### Information Requested

This Notice has been prepared to obtain public views on the above proposals. Comments may be submitted on any topic related to the new 5-year program. Comments are requested in particular on the following specific topics.

(1) The proposed configuration of planning area boundaries, including the deferral of leasing in the 15 subareas described above.

(2) The 13 subareas highlighted for further analysis and comment: three subareas extending 15 nautical miles offshore in the North, South, and Mid-Atlantic planning areas; the Gulf of Maine; the National Aeronautics and Space Administration Flight Clearance Zone offshore Cape Canaveral (extending to 170 nautical miles offshore); a subarea offshore the Florida Gulf Coast extending between 20 and 30 nautical miles from shore from Naples to Apalachicola; the subarea south of 26° N. latitude and east of 82° W. longitude in the "Miami" official protraction diagram offshore Florida in the Eastern Gulf of Mexico; the three subareas estimated by MMS to be beyond the area of hydrocarbon potential in the Wahington-Oregon, Northern California, and Central California planning areas; two subareas totaling approximately 210 blocks adjacent to Unimak Pass, Alaska, in the St. George Basin and North Aleutian Basin planning areas; and a subarea of approximately 59 blocks offshore Point Barrow, Alaska. Maps depicting these subareas will appear in the draft EIS and separate copies of them can be obtained by calling the contact person indicated above.

(3) The appropriateness of the number of proposed sales and the interval between proposed sales; and, in particular, whether there should be biennial rather than triennial sales in the Eastern Gulf of Mexico.

(4) The appropriateness of the location of proposed sales; and, in particular, whether there should be a sale in 1991 in the portion of the Straits of Florida planning area south of 25°07′ N. latitude.

(5) The proposed presale process of focusing on promising acreage; and, in particular, the following possible techniques for implementing that approach:

(A) The recommendation of Massachusettes that nomination procedures be revised so as to request more detailed information from industry on areas of interest prior to the issuance of the Call (to be displayed in the Call), and again after the issuance of the draft EIS.

(B) The recommendations of the American Petroleum Institute, the National Ocean Industries Association, and a number of oil and gas producers that nomination procedures be revised so as to request more detailed information concerning "negative nominations."

(C) A sale-by-sale decision on whether to publish a notice in the **Federal Register** announcing the availability of the MMS proposed Call area for industry interest review prior to the issuance of the Call.

(6) The proposed means of pursuing flexibility in the new program in light of national energy needs and uncertainty over future oil and gas supplies and prices; and, in particular, the following possible economic criteria for the acceleration provision—

(I) Activation of the International Energy Agency's oil sharing agreement;

(II) Drawdown of the Strategic Petroleum Reserve (SPR) because of a severe oil supply disruption;

(III) Major disruption in Mideast oil shipments;

(IV) Imports of crude oil and refined petroleum products (excluding those for the SPR) reach a specific percentage of the trade deficit over a specified period;

(V) Imports of crude oil and refined petroleum products (excluding those for the SPR) reach a specific percentage of total domestic consumption of petroleum products over a specified period;

(VI) The price of imported crude oil (U.S. refiners' acquisition cost as computed by the Energy Information Administration (EIA)) rises by a specified amount or percent over a specified period;

(VII) Net imports of petroleum (excluding those for the SPR) are projected by EIA to equal or exceed a specified percent of U.S. consumption of refined petroleum products;

(VIII) Oil prices are projected by EIA to increase by a specified amount or percent or reach a specified level.

In light of the reconfiguration of planning areas resulting from the 15 subarea deferrals proposed by the Secretary, industry respondents in particular are requested to re-rank all 26 planning areas of the OCS. Separate rankings are requested for: (i) Hydrocarbon potential; and (ii) exploration and development interest. Both rankings should be based on estimates of resources expected to be unleased as of January 1987. Industry respondents are also asked to indicate those areas in which they intend to operate or have serious interest in leasing or operating so that their rankings can be interpreted most usefully by MMS. Industry respondents are also requested to indicate whether the deferral of leasing in any of the subareas highlighted in comment topic 2, above, would result in a significant decrease in the rank of the affected planning area(s).

Confidential treatment of privileged or proprietary information is authorized under section 18(g) of the OCS Lands Act. In order that only rankings be treated as confidential, they should be submitted as an attachment to the other comments which a respondent submits. An attachment to a response containing privileged or proprietary information will, upon request, be treated as confidential from the time of receipt by MMS until 5 years after final approval of the next leasing program. However, summaries of rankings submitted to MMS, the names of respondents submitting rankings, and comments other than rankings will not be treated as confidential information.

Dated: February 4, 1986.

**William D. Bettenberg,**

*Director, Minerals Management Service.*

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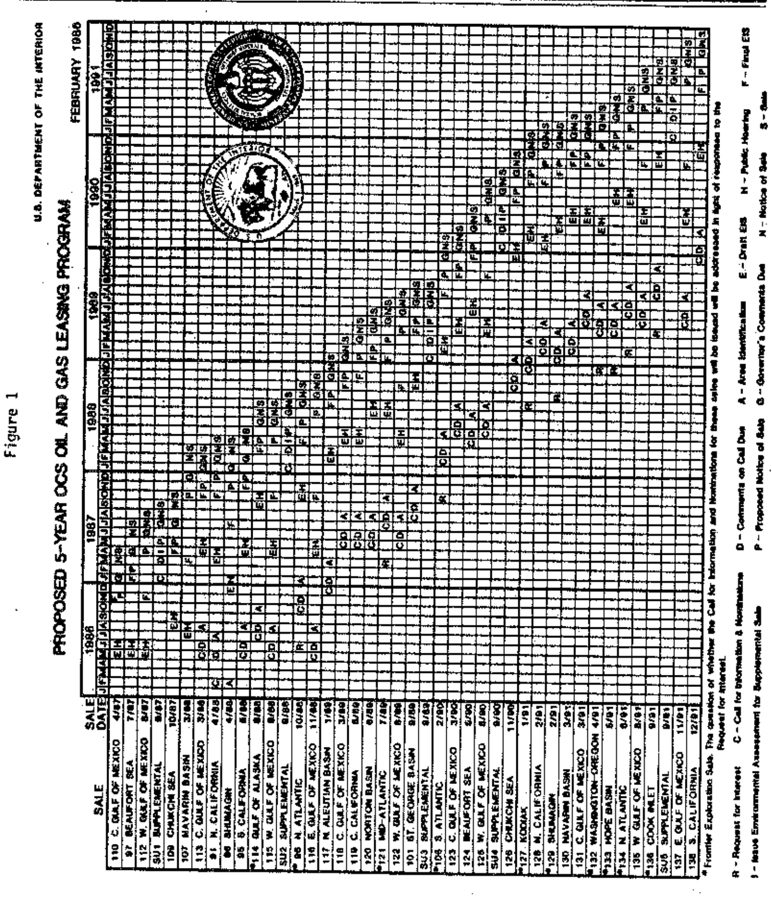
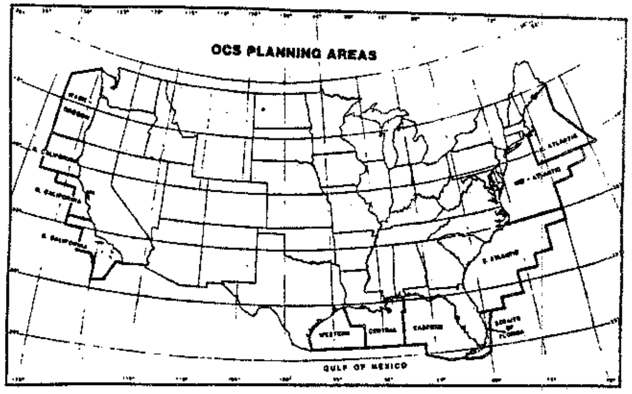
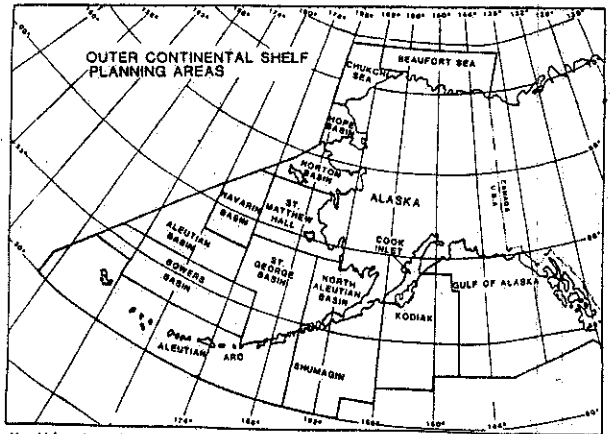



Figure 1

Map 1




Map 2




Maritime boundaries and limits depicted on the maps and divisions shown between planning areas are for initial planning purposes only and do not prejudice or affect United States jurisdiction in any way.

[FR Doc. 86-2750 Filed 2-6-86; 8:45 am]

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Minerals Management Service

**Request for Comments on Appendix P: Analysis of Tract Selection and Areawide Leasing Approaches (an Appendix to the Secretarial Issue Document for the Upcoming Proposed 5-Year Outer Continental Shelf (OCS) Oil and Gas Leasing Program)**

**DATES:** Comments must be received by September 13, 1985.

**ADDRESSES:** Comments should be submitted to the Deputy Associate Director for Offshore Leasing, Minerals Management Service, Room 4229, Mail Stop 641, 18th and C Streets, NW., Washington, D.C. 20240.

**FOR FURTHER INFORMATION CONTACT:** Copies of the Appendix may be requested by writing to the above address or by contacting Tim Redding at (202) 343-1072. Questions on the substance of the Appendix may be directed to Don Sant at (202) 343-3526 or Ted Heintz at (202) 343-7258.

**SUPPLEMENTARY INFORMATION:** An initial version of the Secretarial Issue Document for the new 5-year program (including Appendix P) was issued on March 21, 1985. Based on comments received on that initial version and additional analysis, a revised version of Appendix P has been prepared and is now available for further public comment. Comments on the revised version of Appendix P have been requested from the Governors of all coastal States.

**SUMMARY:** The change in 1983 from tract selection to areawide OCS lease sales caused considerable controversy on several grounds. This appendix analyzes those aspects of the controversy concerning investment and revenues. It evaluates the extent to which experience with areawide leasing has achieved its objectives and borne out the concerns expressed about its effects. It also discusses the implications of the new 5-year leasing program.

The most important conclusions from this analysis are that areawide leasing may have caused:

- Substantial increases in the investments in leasing and exploration needed to reap the energy and economic benefits of OCS resources;
- A relatively small part of the total decline in bonuses observed in leasing during 1983 and 1984; and
- A substantial increase in the total return to the U.S. treasury from accelerated leasing of OCS oil and gas.

Central to the analysis is the concept of the OCS lands as an inventory of investment opportunities. An analytic

framework is developed which accounts for changes in the inventory of unleased tracts that can occur as a result of changing economic conditions (particularly oil price expectations), changing geologic knowledge, and the different leasing rates that can occur. The status of the inventory depends not only on the economic and geologic conditions that make prospects valuable, but on the way in which tracts have been sold from the inventory in previous years. Changes in the Government's inventory of unleased tracts are reflected in changes in the characteristics of the tracts sold in subsequent sales. Thus, as sales proceed, the amount of acreage leased, its value, the cash bonus revenue collected by the Government, and the subsequent level of investment in exploration would be expected to change as the nature of the unleased inventory changed.

Two key objectives of areawide leasing were to expand the amount and location of acreage leased and to increase the rate of investment in exploration. Critics expressed related concerns that industry did not have the capital to expand its investment and that leases would be acquired, but not explored or developed until years later. This appendix examines data on the experience under tract selection and areawide leasing. It shows that during the 1976–1982 period leasing and investment in exploration did not expand as price increases made more tracts attractive for investment. As a result, the Government's inventory of unleased acreage worth investing in grew in size and value. Areawide leasing in 1983 and 1984 substantially increased industry's investment in lease acquisition and exploration, particularly in the Gulf of Mexico. There is also evidence that there will continue to be increased exploration investment in the future, based on the exploration plans that have been submitted in recent years.

The buildup of the inventory in the 1976–1982 period and its drawdown in 1983–1984 also had important revenue consequences. Critics of areawide leasing charged that competition would be so thinned by offering much more acreage that bonus bids would decline and the fair market value requirement of section 18(a)(4) would be violated. This appendix shows that the restricted leasing in tract selection sales of the 1976–1980 period increased average bonus bids per acre, primarily by withholding tracts from sale while their value appreciated. Total revenues from bonuses in that period were limited because of the limited amount of acreage leased.

In contrast, areawide leasing in 1983 and 1984 drew down the inventory rapidly. This accelerated leasing resulted in receiving revenues much earlier than would have been the case under tract selection procedures. Bonuses have been received in the 1983–1984 period that would otherwise have been spread out over the 1983–1991 period. Ultimately, royalties and taxes will also be received earlier. This paper estimates that, under the actual leasing rates in the Central and Western Gulf of Mexico in 1983 and 1984, bonuses would have to have been increased, perhaps by as much as $8.3 million higher per tract, under the leasing rates of tract selection procedures to yield the same present value of revenues as will be realized by the Federal Government from areawide lease sales in those areas.

The drawdown in the inventory also resulted in decreasing average bids although total revenues from bonuses increased, particularly in 1983. Fewer high value tracts and more low value tracts were leased in subsequent sales. The trend of decreasing average bids began, however, in 1980, well before the start of areawide leasing. This appendix concludes that such variations in the average [illegible] indicate a violation of the fair market value requirement. This provision does not require the Secretary to maximize bonus revenues by withholding tracts while their value appreciates [illegible] the value of many tracts [illegible] decreasing during the 1983–1984 period because of declining oil price expectations and may have continued to decline in 1985.

Critics of areawide leasing charged that it would thin competition by spreading a limited number of bidders and their limited capital over too much acreage. Less competition, they claimed, would mean lower bids and violation of the fair market value requirement of section 18(a)(4) of the OCS Lands Act. The Secretary and the courts recognized in 1982 that bonuses might decline under areawide leasing. The court rejected the claim that this meant a violation of the fair market value requirement. Nevertheless, the relationship between the pace of leasing, the number of bids, and the amount paid in bonuses remains a matter of controversy.

This appendix shows that the average number of bids per tract declined during the 1980–1984 period as average bids declined. The percentage of tracts receiving one bid increased while the percentage receiving two or more bids decreased. These trends began before the implementation of areawide leasing [illegible] areawide sales. In addition, [illegible] should increase [illegible] minimum bid implemented in 1982 would be expected to lead to fewer [illegible] per tract on average. It is difficult, however, to isolate the effects of fewer bids on the bid levels from the effects of declining tract values on the number of bids. Since average bids declined more on tracts receiving more than two bids than on tracts receiving only one or two bids, it is reasonable to conclude that most of the decline in average bids was caused by factors other than competition.

A statistical analysis of leasing and bidding data was performed to determine whether and to what extent the implementation of areawide leasing caused a reduction in bonuses. The conclusion from an approach using [illegible] accepted statistical techniques is that there is little evidence that areawide leasing was the primary cause of the substantial decline in bonuses. Further analysis using improved data and more sophisticated methods is needed to overcome important limitations identified in this analysis. The results at this stage in the analysis, however, indicate that the bonus declines associated with areawide leasing were, in all likelihood, much smaller than the [illegible] gains from earlier leasing [illegible] evidence that the [illegible] will come out ahead.

[illegible] the [illegible] concept, this appendix shows that if oil prices are expected to be stable and past areawide leasing has drawn down the inventory of unleased acreage, then areawide and tract selection procedures could cause similar types and amounts of acreage to be leased in future sales. The patterns of competition, the levels of bids, and the implications for meeting the fair market value requirement would also be similar. If oil prices and price expectations rise, however, tract selection and areawide leasing procedures could yield different results. If tract selection sales withheld leasable tracts while tract values were appreciating, competition would tend to increase as the value of tracts offered rose. Areawide procedures would allow less appreciation in tract values before they drew bids, thus would cause a smaller increase in the number of bidders.

Dated: August 14, 1985.

William D. Bettenberg,

*Director, Minerals Management Service.*

[FR Doc. 85-19864 Filed 8-16-85; 8:45 am]

BILLING CODE 4310-MR-M





**Extension of Period of Confidentiality for Privileged or Proprietary Data Submitted in Response to the Request for Comments on the Draft Proposed 5-Year Outer Continental Shelf (OCS) and Gas Leasing Program for Mid-1986 through Mid-1991.**

**SUMMARY:** The Request for Comments on the Draft Proposed 5-Year OCS Oil and Gas Leasing Program for Mid-1986 through Mid-1991 was published in the **Federal Register** on March 22, 1985 (50 FR 11585).

In that Notice, it was stated that "Industry respondents in particular are requested to rank all planning areas of the OCS which now number 26 instead of 24. In order to encourage the frankest response, each respondent's ranking, upon request, will be deemed to be privileged or proprietary information to be treated as confidential for a period of 2 years after receipt by MMS (the Minerals Management Service). Confidential treatment of information is authorized under section 18(g) of the OCS Lands Act."

Section 18(g) of the OCS Lands Act does not specify any period for confidentiality. Two years was chosen so as to cover the period of development of the new program. Based upon preliminary response to the Request for Comments published in the **Federal Register**, it has been determined that the period for confidentiality should correspond to the period to be covered by the new program.

Consequently, upon request, individual rankings of planning areas will be treated as confidential privileged or proprietary data for a period of 5 years after final approval of the new 5-year program. Any other privileged or proprietary data submitted with comments on the Draft Proposed 5-Year Program will be treated as confidential for the period provided by the OCS Lands Act and regulations in Chapter II of Title 30 of the Code of Federal Regulations.

While each ranking attachment will be treated as confidential information for a period of 5 years after final approval of the new 5-year program, summaries of rankings prepared by MMS, the names of respondents submitting rankings, and comments other than rankings will not be treated as confidential information.

**DATES:** No comments are requested on this notice. Comments on the Draft Proposed 5-Year Program, as indicated in Notice published in the Federal Register on March 22, 1985, must be received by May 20, 1985.

**ADDRESSES:** Comments on the Draft Proposed 5-Year Program should be submitted to the Deputy Associate Director for Offshore Leasing, Minerals Management Service (MMS), Mail Stop 641, 12203 Sunrise Valley Drive, Reston, Virginia 2091. Hand deliveries to the Department of the Interior may be made to Room 2525, 18th & C Streets, NW., Washington, D.C. 20240. Envelopes or packages should be marked "Comments on the Draft Proposed 5-Year OCS Leasing Program." If any privileged or proprietary information which the respondent wishes to be treated as confidential is attached to comments, the envelope or package should be marked "Contain confidential information."

**FOR FURTHER INFORMATION CONTACT:** Telephone contact may be made with Chris Oynes, Chief, Offshore Leasing Management Division, MMS, at (202) 343-6906, or Paul Stang, Chief, Branch of Program Development and Planning, MMS, at (202) 343-1072.

Dated: May 10, 1985.

William D. Bettenberg,

*Director, Minerals Management Service.*

[FR Doc. 85-11747 Filed 5-13-85; 8:45 am]

BILLING CODE 4310-MR-M

**Outer Continental Shelf Oil and Gas Leasing Program; Mid-1988 Through Mid-1991; Inquiry**

**AGENCY:** Minerals Management Service, Interior.

**ACTION:** Request for Comments on the Draft Proposed 5-Year Outer Continental Shelf (OSC) Oil and Gas Leasing Program for Mid-1988 through Mid-1991.

**SUMMARY:** The Secretary of the Interior has just transmitted to the Governors of the affected coastal States and to the heads of affected Federal Agencies for review and comment the Draft Proposed 5-Year OCS Oil and Gas Leasing Program, prepared pursuant to section 18 of the OCS Lands act, as amended. That transmission is a formal but early step on the approximately 2-year process of analysis and consultation required for development of a new 5-year OSC oil and gas leasing program. The process was begun in July 1984 with letters to coastal State Governors and affected Federal Agencies and a **Federal Register** Notice (49 FR 28332, July 11, 1984) requesting initial comments and information on development of the new 5-year program. The Draft Proposed Program consists of a preliminary schedule of sales including presale milestones for the period July 1988 through June 1991 and a selection of leasing policies. These policies concern the configuration of OCS planning areas, the size of sales as determined by the presale process, and the means of assuring the receipt of fair market value for lands leased and rights conveyed. A Notice of intent to prepare an environmental impact statement (EIS) also appears in today's **Federal Register**. This Notice seeks public comments on the schedule and policies selected as the Draft Proposed Program. The responses to this Notice will be considered for the Secretarial decision on the adoption of a Proposed 5-Year OCS Oil and Gas Leasing Program planned for release in the summer of 1985. That release will be followed by a further 90-day comment period and further evaluation.

**DATES:** Comments must be received by May 20, 1985.

**ADDRESSES:** Comments should be submitted to the Deputy Associate Director for Offshore Leasing, Minerals Management Service (MMS), Mail Stop 641, 12203 Sunrise Valley Drive, Reston, Virginia 22091. Hand deliveries to the Department of the Interior may be made to Room 2525, 18th & C Streets NW., Washington, D.C. 20240. Envelopes or packages should be marked "Comments on the Draft Proposed 5-Year OCS Leasing Program." If any privileged or proprietary information which the respondent wishes to be treated as confidential is attached to comments, the envelope or package should be marked "Contains confidential information."

**FOR FURTHER INFORMATION CONTACT:** Telephone contact may be made with Chris Oynes, Chief, Offshore Leasing Management Division, MMS, at (202) 343–6906, or Paul Stang, Chief, Branch of Program Development and Planning, MMS, at (202) 343–1072.

Author: Robert Samuels, Branch of Program Development and Planning, MMS.

**SUPPLEMENTARY INFORMATION:** The Department of the Interior (DOI) has developed the Draft Proposed Program within the framework of section 18 of the OCS Lands Act, as amended. Section 18 requires that the 5-year program be designed to meet national energy needs. Thus, one objective of the program is to allow all parties to plan for OCS leasing activities while providing sufficient flexibility to meet national energy needs.

Pursuant to section 18, the schedule and policies selected for the Draft Proposed Program were based on a consideration of a number of factors, specified by the act and provide "to the maximum extent practicable, a proper balance between the potential for environmental damage, the potential for the discovery of oil and gas, and the potential for adverse impact on the coastal zone."

The preliminary decisions made for the Draft Proposed Program are described below. This is the first of several steps in the development of the new program. The proposals which comprise the Draft Proposed Program will be reviewed at the later program development stages: the Proposed Program, schedule for release in the summer of 1985; the Proposed Final Program, planned for the spring of 1986; and final approval. Secretarial approval of a final new 5-Year OSC Oil and Gas Leasing Program will follow appropriate consultation and a 60-day notification period before Congress.

Maps and a table showing the planning areas and their geographic boundaries appear at the end of this Notice along with Figure 1 which depicts the leasing schedule selected for the Draft Proposed Program.

### 1. Planning Area Boundaries for the Draft Proposed Program

In the July 1984 **Federal Register** Notice requesting comments on the development of the new program, 24 OCS planning areas were depicted. The Draft Proposed Program selection revises the July 1984 description by establishing outer boundaries for planning areas and reconfiguring the OCS into 26 planning areas.

This reconfiguration has two parts: the division of the South Atlantic into two areas (South Atlantic and Straits of Florida) to allow a more concentrated review of those areas under the provisions of section 18; and the reconfiguration of planning areas offshore California from two to three to allow a more concentrated section 18 review of those areas as well as to respond to public comments.

The key factor in the reconfiguration of the areas offshore California is that there are discoveries in the basin on both the south and west sides of Santa Barbara County. It will thus be better for planning and administrative purposes to treat them together for the scheduling of lease sales and analyzing in a single EIS potential impacts on air quality, transportation of oil and gas, and other environmental factors. The other four basins offshore California are divided equally, i.e., two and two, to form the new Central and new Northern California planning areas.

In addition to the above reconfiguration of planning areas, outer boundaries have been selected. The outer boundaries of the Washington-Oregon and Northern California areas are being set at 128° W. longitude so as to encompass the area of hydrocarbon potential in those regions. In the Beaufort Sea, Official Protraction Diagram NS 7–8 is being added so as to include that area for consideration for leasing in the new program.

### 2. The Leasing Schedule for the Draft Proposed Program

Over the period mid-1988 through mid-1991, the Draft Proposed Program provides for 33 standard sales, 5 frontier exploration sales, and 5 supplemental sales.

This contrasts with the current program (as approved in July 1982), which provided for 40 standard sales and 1 reoffering sale. The new draft schedule proposes the continuation of annual sales in the two highest-value, highest-interest areas: the Central and Western Gulf of Mexico. It proposes triennial sales in 15 other areas. This triennial pacing of sales contrasts with the biennial pace in the current 5-year program. Other features of the proposed schedule are described below.

The first OCS sale in 27 years is proposed for 1991 offshore Washington and Oregon given the value of that area's resources and industry interest. The schedule also proposes the first sale in Hope Basin, offshore Alaska, also in 1991. The sales for these areas are proposed late in the 5-year period to allow time for the necessary environmental studies to be performed.

*a. The Base Schedule*

The base schedule proposes 33 standard sales in 17 planning areas. The 11 sales numbered in Figure 1 are sales carried over from the current to the new program.

*b. Frontier Exploration Sales Offshore Alaska*

Five frontier exploration sales have been proposed offshore Alaska to increase the flexibility of the schedule to respond to changes in prices and other economic conditions or improved geologic and geophysical data. These five sales are proposed for the Gulf of Alaska (1988), Cook Inlet (1989), Shumagin (1990), Hope Basin (1991), and Kodiak (1991). The 1987 Shumagin sale, Sale 86, is carried over from the current schedule as a standard sale. In these frontier areas, the assessment of oil and gas resources is incomplete, and at this time, industry interest appears low.

These frontier exploration sales will include an additional presale step: a Request for Interest scheduled for 4 months prior to the Call for Information and Nominations. Responses to each Request will be used to help determine whether the approximately 2-year sale process should proceed in those areas. The annual review of the program under section 18(e) will also be used to determine whether to proceed with these sales.

*c. Supplemental Sales*

The schedule also includes an annual sale for a limited number of selected blocks in areas other than the Central and Western Gulf of Mexico: drainage and development blocks; and blocks on which bids were rejected in the preceding calendar year. These sales will provide for: (1) The expeditious offering of blocks in which serious industry interest can reasonably be anticipated; (2) orderly development of OCS resources (increasing the potential for actual development and reducing the time necessary to bring new fields into production); and (3) minimization of costs of delay. These blocks will only be offered after compliance with the requirements of the National Environmental Policy Act, the OCS Lands act, and other applicable statutes. The environmental assessment documentation for each of these sales would be released at approximately the same time as the Proposed Notice of Sale. If it is determined that an EIS is required for one of these sales, revised presale milestones will be issued.

*d. Areas in Which no Sales Are Proposed in the Draft Proposed Program*

The schedule proposes no sales in St. Matthew-Hall, Aleutian Arc, Aleutian Basin, and Bowers Basin so as to concentrate management resources on other areas with higher resource potential and industry interest. Comments are requested on this part of the proposal in the final section of this Notice. No sale has been scheduled for the Straits of Florida since this area has not yet been analyzed as a separate planning area. Section 18 analysis of and comments on the Straits of Florida as a new planning area will be available for the decision on the Proposed Program.

*e. Flexibility Provision*

The DOI must plan for an unknown future with limited information. Changes in the world energy market as well as exploration results in frontier areas can dramatically affect the demand for offshore leases. The statutory requirement to develop "a schedule of proposed lease sales indicating, as precisely as possible, the size, timing, and location of leasing which [the Secretary] determines will best meet national energy needs for the 5-year period following its approval . . ." must be applied with due recognition that what will be known tomorrow may well be very different from what is known today.

To comply fully with the statutory requirement to meet national energy needs over the 5 years of the program, the schedule should have the flexibility to respond to changing conditions. Thus, the new program includes a provision to accelerate sales in areas of higher value and/or higher interest (but not so as to increase the total number of sales in any planning area in the approved program). The areas where such acceleration would be considered include: Southern California; Eastern Gulf of Mexico; Central California; Northern California; Navarin Basin; Beaufort Sea; North Aleutian Basin; and St. George Basin. Specific guidelines for the implementation of the acceleration provision will be developed for the Proposed Program and available for public comment before final approval of the program.

Such a provision would be used only if warranted by changes in economic conditions (for example, substantially higher oil price expectations such as might result from a serious oil supply disruption) or geologic data (such as could come from major new discoveries). The question of whether to accelerate a sale in an area would be made on a sale-by-sale basis, as part of the required annual review of the program under section 18(e). No new sales would be added to the program in any planning area under this provision.

### 4. Size of Lease Sales

It is proposed that the size of lease sales be determined by a presale process which results in the offering of promising acreage. Promising acreage is that which is reasonably determined to be likely to lead to exploration and/or development of oil and gas resources. That determination will be made by means of a consultative process which will provide for the early resolution of conflicts based on information and nominations obtained from affected Federal Agencies, State and local governments, the public, and potential bidders, as well as Minerals Management Service analysis.

The offering of promising acreage will give effect to DOI's desire to make available for lease areas of hydrocarbon potential as identified by industry and MMS, while remaining cognizant of the particular circumstances relevant to each sale. The various OCS areas and the adjacent onshore regions vary significantly in terms of exploration and development history, onshore support capability, and possible multiple-use conflicts. In preparing for leasing activity, regional differences will be taken into account on a case-by-case, sale-by-sale basis, and the emphasis will be on consultation, and, wherever possible, consensus.

### 5. Assurance of Receipt of Fair Market Value in the Draft Proposed Program

Section 18(a)(4) provides that leasing activities are to be conducted so as to assure receipt of fair market value for lands leased and rights conveyed. The policy option selected for the Draft Proposed Program maintains current procedures for assuring the receipt of fair market value. In 1984, a number of adjustments were made to improve fair market value procedures based upon evaluations of these procedures conducted by MMS independent of the formulation of the new leasing program. The policy option selected also provides for a review under the auspices of the development of the new 5-year program of the question of whether the minimum bid level should be changed either in general or on a variable basis for different planning areas.

Information requested

This Notice has been prepared to obtain public views on the above proposals. Comments may be submitted on any topic related to the new 5-year program.

Comments are requested on the following specific topics:

(1) The proposed configuration of planning area boundaries.

(2) The appropriateness of the number of proposed sales and the interval between proposed sales.

(3) The appropriateness of the location of proposed sales.

(4) The proposed presale process.

(5) The proposed means of pursuing flexibility in the new program in light of uncertainty over future oil and gas prices and national energy needs.

(6) Whether considerations such as the following concerning the level of the minimum bid would warrant varying the current minimum bid level of $150 per acre on a nationwide or planning area basis: (1) Changes in economic conditions such as oil prices; or (2) potential effects on the number of tracts leased or the rate of exploration and development.

(7) Whether the tract size limit of 5,760 acres ought to be expanded; and whether enlargement of the maximum tract size is an alternative which would achieve effects comparable to varying the minimum bid. Under section 8(b)(1) of the OCS Lands Act, the Secretary of the Interior has the authority to enlarge the maximum tract size if necessary to comprise a reasonable economic production unit.

(8) Whether there are subareas within planning areas which should be subject to special considerations, either in the presale planning process for each sale or, more generally, within the 5-year program itself, and what those considerations should be.

Industry respondents in particular are requested to rank all planning areas of the OCS which now number 26 instead of 24. In order to encourage the frankest response, each respondent's ranking, upon request, will be deemed to be privileged or proprietary information to be treated as confidential for a period of 2 years after receipt by MMS. Confidential treatment of information is authorized under section 18(g) of the OCS Lands Act. In order that only rankings be treated as confidential, they should be submitted as an attachment to the other comments a respondent submits. While each ranking attachment will be treated as confidential information for a period of 2 years, statistical summaries of rankings



prepared by MMS, the names of respondents submitting rankings, and comments other than rankings will not be treated as confidential information.

Separate rankings are requested for: (i) Hydrocarbon potential; and (ii) exploration and development interest. Both rankings should be based on estimates of resources expected to be [illegible] Industry respondents are also asked to indicate those areas in which they have intentions to operate or serious interest in operating so that their rankings can be interpreted most usefully by MMS.

The following maps and Table 1 depict and describe the planning area [illegible] selected as part of the Draft Proposed Program. Figure 1 depicts the leasing schedule selected for the Draft Proposed Program.

Dated: March 19, 1985.

**William D. Bettenberg,**

*Director, Minerals Management Service*

BILLING CODE 4310-MR-M

U.S. Department of the Interior
Minerals Management Service

Figure 1
DRAFT PROPOSED PROGRAM

MARCH 1985

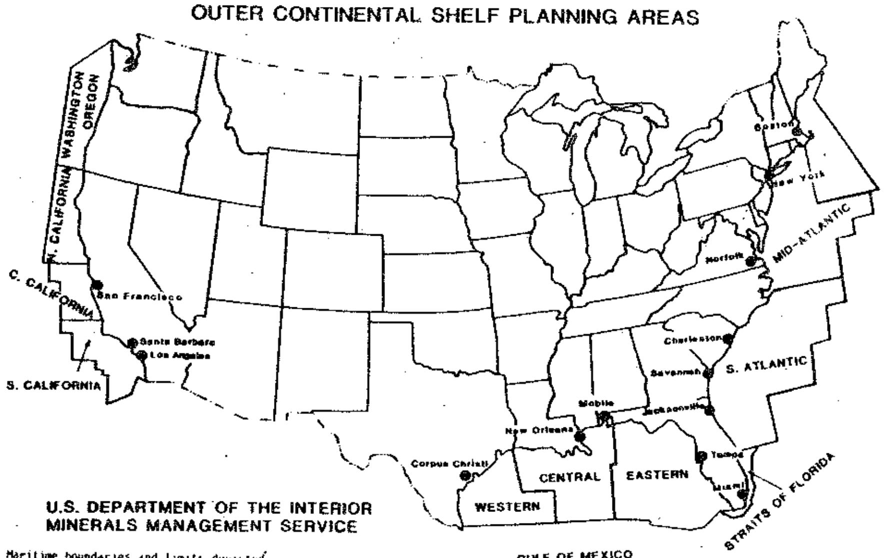
| SALE | AREA | PROPOSED DATE | 1985 JFMAMJJASOND | 1986 JFMAMJJASOND | 1987 JFMAMJJASOND | 1988 JFMAMJJASOND | 1989 JFMAMJJASOND | 1990 JFMAMJJASOND | 1991 JFMAMJ |
|---|---|---|---|---|---|---|---|---|---|
| 105 | W. Gulf of Mexico | 7/86 | EH F | P G NS | | | | | |
| | Supplemental 1 | 8/86 | | P GNS | | | | | |
| 107 | Navarin Basin | 9/86 | EH | FP GNS | | | | | |
| 97 | Beaufort Sea | 12/86 | A EH | FP G NS | | | | | |
| 95 | S. California | 4/87 | C A | EH FP | GNS | | | | |
| 110 | C. Gulf of Mexico | 4/87 | C A | EH FP | GNS | | | | |
| 109 | Chukchi Sea | 5/87 | C A | EH F | P GNS | | | | |
| | W. Gulf of Mexico | 8/87 | C A | EH F | P GNS | | | | |
| | Supplemental 2 | 8/87 | | | P GNS | | | | |
| 96 | N. Atlantic | 11/87 | | C A E | H FP GNS | | | | |
| 86 | Shumagin | 12/87 | C | A | EH FP GNS | | | | |
| 91 | N. California | 12/87 | | C A | EH FP GNS | | | | |
| | C. Gulf of Mexico | 2/88 | | C A | EH FP G | NS | | | |
| | Gulf of Alaska | 3/88 | R | C A | EH FP | GNS | | | |
| | E. Gulf of Mexico | 5/88 | | C A | EH F | P GNS | | | |
| 101 | St. George Basin | 7/88 | | C A | EH | FP GNS | | | |
| | W. Gulf of Mexico | 8/88 | | C A | EH F | P GNS | | | |
| | Supplemental 3 | 8/88 | | | | F GNS | | | |
| | Mid-Atlantic | 10/88 | | C | A EH | FP GNS | | | |
| | N. Aleutian Basin | 12/88 | | C | A | EH FP GNS | | | |
| | C. Gulf of Mexico | 2/89 | | | C A | EH FP G | NS | | |
| | Norton Basin | 3/89 | | | C A | EH FP | GNS | | |
| | C. California | 6/89 | | | C A | EH F | P GNS | | |
| 108 | S. Atlantic | 7/89 | | | C A | EH | FP GNS | | |
| | W. Gulf of Mexico | 8/89 | | | C A | EH F | P GNS | | |
| | Supplemental 4 | 8/89 | | | | | P GNS | | |
| | Navarin Basin | 9/89 | | | C A | EH | FP GNS | | |
| | Beaufort Sea | 12/89 | | | C | A | EH FP GNS | | |
| | C. Gulf of Mexico | 2/90 | | | | C A | EH FP G | NS | |
| | Chukchi Sea | 3/90 | | | | C A | EH FP | GNS | |
| | S. California | 4/90 | | | | C A | EH FP | GNS | |
| | Cook Inlet | 6/90 | | | | R C A | EH | FP GNS | |
| | W. Gulf of Mexico | 8/90 | | | | C A | EH F | P GNS | |
| | Supplemental 5 | 8/90 | | | | | | F GNS | |
| | Shumagin | 9/90 | | | | R C A | EH | FP GNS | |
| | N. Atlantic | 10/90 | | | | C | A EH | FP GNS | |
| | N. California | 12/90 | | | | | C A | EH FP GNS | |
| | Kodiak | 1/91 | | | | R C | A | EH FP GN | S |
| | C. Gulf of Mexico | 2/91 | | | | | C A | EH FP G | NS |
| | St. George Basin | 4/91 | | | | | C A | EH FP | GNS |
| | Washington-Oregon | 4/91 | | | | | C A | EH FP | GNS |
| | E. Gulf of Mexico | 5/91 | | | | | C A | EH F | P GNS |
| | Hope Basin | 6/91 | | | | | R C A | EH | FP GNS |

R - Request for Interest C - Call for Information & Nominations A - Area Identification
E - Draft EIS H - Public Hearing F - Final EIS P - Proposed Notice of Sale
G - Governor's Comments Due N - Notice of Sale S - Sale





OUTER CONTINENTAL SHELF PLANNING AREAS

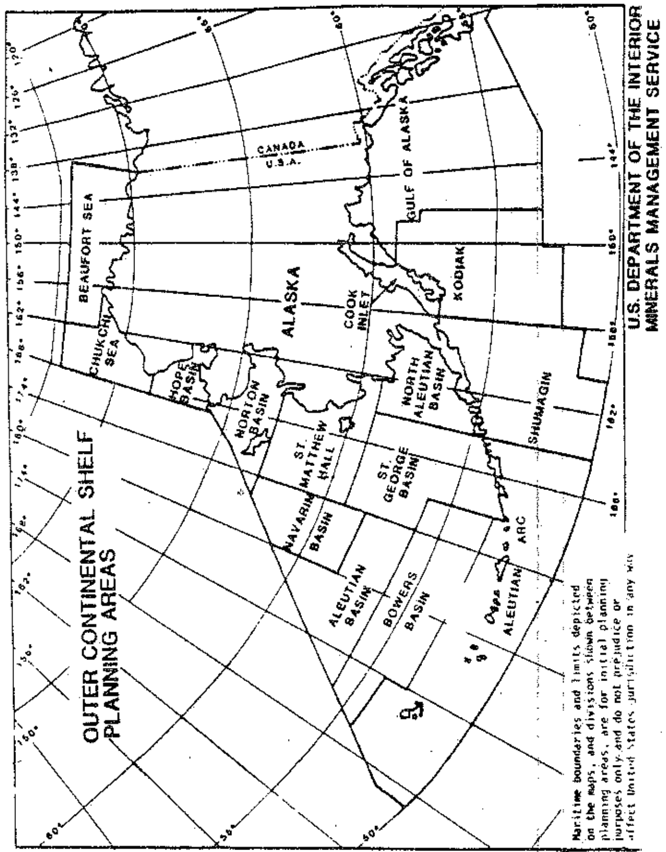



U.S. DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE

Maritime boundaries and limits depicted on the maps, and divisions shown between planning areas, are for initial planning purposes only and do not prejudice or affect United States jurisdiction in any way

Map 1

Map 2




BILLING CODE 4310-MR-C



**Table 1—Description of Planning Areas**

1. North Atlantic: Extends south from the juncture of the territorial sea at 71° W longitude to 39° N latitude thence east to the juncture of an extension of the U.S.-Canada Maritime Boundary thence north along that extension to the territorial sea thence following the territorial sea to the point of origin.

2. Mid-Atlantic: Extends east from the juncture of the territorial sea at approximately 35° N latitude to 70° W longitude thence north to approximately 37° N latitude thence east to 68° W longitude thence north to approximately 38° N latitude thence east to 66° W longitude thence north to 39° N latitude thence west to 71° W longitude thence north to the territorial sea thence along the territorial sea to the point of origin.

3. South Atlantic: East from the juncture of the territorial sea at approximately 35° N latitude to 70° W longitude thence south to 34° N latitude thence west to 72° W longitude thence south to 32° N latitude thence west to 74° W longitude, thence south to 31° N latitude thence west to 78° W longitude thence south to 28°17′ N latitude thence west to the territorial sea limits thence north along the territorial sea to the point of origin.

4. Straits of Florida: East from the juncture of the territorial sea at 28°17′ N latitude to 78° W longitude thence south to the limits of U.S. jurisdiction thence southwest along the line of U.S. jurisdiction to approximately 81°13′ W longitude at 23°55′ N latitude thence west to 83° W longitude thence north to the territorial sea abutting the Dry Tortugas thence east to the limits of the territorial sea thence along the territorial sea to the point of origin.

5. Eastern Gulf of Mexico: South from the territorial sea at approximately 87°45′ W longitude to approximately 29° N latitude thence west to approximately 87°55′ W longitude thence south to approximately 26° N latitude thence east to approximately 85°55′ W longitude thence south to the limit of U.S. jurisdiction thence southeast to approximately 83°55′ W longitude at approximately 24° N latitude thence east to 83° W longitude thence to the limits of the territorial sea thence east to approximately 82°25′ W longitude thence north and east along the territorial sea to the limits of U.S. jurisdiction thence along the territorial sea to the point of origin.

6. Central Gulf of Mexico: South from the territorial sea at approximately 87°45′ W longitude to approximately 29° N latitude thence west to approximately 87°55′ W longitude thence south to approximately 26° N latitude thence west to approximately 91°55′ W longitude, except that between approximately 88°23′ W longitude and 91°05′ W longitude the boundary is the U.S.-Mexico Provisional Maritime Boundary, thence north to approximately 27°55′ N latitude thence generally west to approximately 93°25′ W longitude thence northwest to the juncture of the territorial sea at approximately 93°50′ W longitude thence east along the territorial sea to the point of origin.

7. Western Gulf of Mexico: East from the territorial sea along the U.S.-Mexico Provisional Maritime Boundary to approximately 25°45′ N latitude thence along approximately 26° N latitude to approximately 91°55′ W longitude thence north to approximately 27°55′ N latitude thence generally west to approximately 93°25′ W longitude thence northwest to the juncture of the territorial sea at approximately 93°50′ W longitude thence along the territorial sea to the point of origin.

8. Southern California: West along a line extending from the territorial sea at approximately 35°47′ N latitude to approximately 124° W longitude thence south to approximately 34°58′ N latitude thence east to approximately 122° W longitude thence south to approximately 32°55′ N latitude thence east to approximately 121°40′ W longitude thence south to approximately 32°40′ N latitude thence east to approximately 120°20′ W longitude thence south to approximately 32°10′ N latitude thence east to 120° W longitude thence south to the U.S.-Mexico Provisional Maritime Boundary thence along the U.S.-Mexico Provisional Maritime Boundary to the territorial sea thence along the territorial sea to the point of origin.

9. Central California: West along a line extending from the territorial sea at approximately 35°47′ N latitude to approximately 124° W longitude thence north to approximately 37°59′ N latitude thence west to approximately 126° W longitude thence north to approximately 38°46′ N latitude thence east to the territorial sea thence along the territorial sea to the point of origin.

10. Northern California: West along a line extending from the territorial sea at approximately 38°46′ N latitude to approximately 128° W longitude thence north to approximately 42° N latitude thence thence east to the territorial sea thence along the territorial sea to the point of origin.

11. Washington-Oregon: West along a line extending from the territorial sea at approximately 42° N latitude to 128° W longitude thence north to the limits of U.S. jurisdiction thence east to the territorial sea thence along the territorial sea to the point of origin.

12. Beaufort Sea: West from the juncture of U.S. jurisdiction at 73° N latitude to 162° W longitude thence south to 71° N latitude thence east to the limits of the territorial sea thence east to the limit of U.S. jurisdiction thence north to the point of origin.

13. Chukchi Sea: East from approximately 169° W longitude at 73° N latitude to 162° W longitude thence south to 71° N latitude thence east to the limits of the territorial sea thence generally southwest to approximately 68°20′ N latitude at 167° W longitude thence west to the U.S.-Russia Convention Line thence north to the point of origin.

14. Hope Basin: Extends west from the juncture of the territorial sea at 68°20′ N latitude to the U.S.-Russia Convention Line thence south along the U.S.-Russia Convention Line to 65°35′ N latitude thence east to the limits of the territorial sea thence along the territorial sea to the point of origin.

15. Norton Basin: Extending west from the juncture of 65°35′ N latitude at 168°15′ W longitude to the U.S.-Russia Convention Line thence generally southwest along that line to approximately 63° N latitude at 175° W latitude thence east to the territorial sea thence along the territorial sea to the point of origin.

16. Navarin Basin: Extends southwest from the juncture of approximately 63° N latitude at the U.S.-Russia Convention Line along that line to 180° longitude thence south to approximately 58° N latitude thence east to 174° W longitude thence north to approximately 63° N latitude thence west to the point of origin.

17. St. Matthew-Hall: West from the territorial sea at approximately 63° N latitude at 165° W longitude to 174° W longitude thence south to approximately 59° N latitude thence east to the territorial sea thence following the territorial sea to the point of origin.

18. St. George Basin: South from 59° N latitude at 174° W longitude to 56° N latitude thence east to 171° W longitude thence south to approximately 52°35′ N latitude thence east to the limits of the territorial sea thence following the territorial sea east to approximately 170°30′ W longitude at 52°40′ N latitude thence east to the limit of the territorial sea at approximately 52°46′ N latitude thence following the territorial sea to approximately 52°48′ N latitude thence east to the limit of the territorial sea thence northeast to 165° W longitude thence north to 59° N latitude thence west to the point of origin.

19. North Aleutian Basin: West from 161°52' W longitude at approximately 59° N latitude to 165° W longitude thence south to the intersection with the territorial sea thence following the territorial sea to the point of origin.

20. Shumagin: Extends south from a point at approximately 54°30' N latitude and 165° W longitude to 50° N latitude thence east to 159° W longitude thence north to 51° N latitude thence east to 158° W longitude thence north to 57° N latitude thence west to the territorial sea thence southwest along the territorial sea to the point of origin.

21. Cook Inlet: Extends east from approximately 56°57' N latitude at 156°25' W longitude to the intersection with the territorial sea thence generally northeast along the territorial sea to approximately 152°27' W longitude thence north to the territorial sea thence around the territorial sea to approximately 59° N latitude at 152° W longitude thence north to the territorial sea thence following the territorial sea to the point of origin.

22. Kodiak: Extends east from 57° N latitude at 158° W longitude to the territorial sea thence generally northeast along the territorial sea to approximately 152°27' W longitude thence north to the territorial sea thence around the territorial sea to approximately 59° N latitude thence east to 148° W longitude thence south to 58° N latitude thence east to 147° W longitude thence south to 53° N latitude thence west to 150° W longitude thence south to 52° N latitude thence west to 158° W longitude thence north to the point of origin.

23. Gulf of Alaska: Extends south from approximately 151°55' W longitude at 59°05' N latitude to the territorial sea at approximately 59° N latitude thence east to 148° W longitude thence south to 58° N latitude thence east to 147° W longitude thence south to 53° N latitude thence east to 141° W longitude thence generally northeast along the fishery conservation line to the territorial sea thence along the territorial sea to the point of origin.

24. Aleutian Basin: East from the juncture of approximately 58° N latitude at the U.S.-Russia Convention Line to 174° W longitude thence north to approximately 58° N latitude thence west to 180° longitude thence north to the juncture of the U.S.-Russia convention line thence along that line to the point of origin.

25. Bowers Basin: East from the juncture of approximately 58° N latitude at the U.S. Russia Convention line to 171° W longitude thence south to approximately 53° N latitude thence west to 174° E longitude thence north to approximately 54° N latitude thence west to the U.S.-Russia Convention Line thence along that line to the point of origin.

26. Aleutian Arc: East from the juncture of the U.S.-Russia Convention Line at approximately 54° N latitude to 174° E longitude thence south to approximately 53° N latitude thence east to 171° W longitude thence south to approximately 52°35' N latitude thence east to the limits of the territorial sea thence following the territorial sea east to approximately 170°30' W longitude at 52°40' N latitude thence east to the limit of the territorial sea at approximately 52°46' N latitude thence following the territorial sea to approximately 52°48' N latitude thence east to the limit of the territorial sea thence northeast to 165° W longitude thence south to approximately 50° N latitude thence west to approximately 167° E longitude thence north to the U.S.-Russia Convention Line thence along that line to the point of origin.

BILLING CODE 4310-MR-M



**Intent To Prepare an Environmental Impact Statement for the Proposed 5-Year Outer Continental Shelf Oil and Gas Leasing Program for Mid-1988 Through Mid-1991**

Pursuant to section 102(2)(C) of the National Environmental Policy Act of 1969, the Department of the Interior's Minerals Management Service (MMS) intends to prepare an environmental impact statement (EIS) regarding a proposed new 5-Year Outer Continental Shelf (OCS) oil and gas leasing program covering the period mid-1988 to mid-1991. The draft EIS is currently scheduled for release in the summer of 1985.

In July 1984, the Department of the Interior requested suggestions and information from the Governors of the affected coastal states, affected Federal Agencies, industry, and the public on the development of a new 5-year leasing program. Information was requested on the characteristics of the OCS planning areas, environmental sensitivity, technological feasibility of exploring and developing certain areas, and the ranking of OCS areas both by oil and gas potential and by interest in exploration and development.

The Secretary of the Interior has just transmitted to the Governors of the affected coastal States and the heads of affected Federal Agencies, for review and comment, the Draft Proposed 5-Year OCS Oil and Gas Leasing Program, prepared pursuant to section 18 of the OCS Lands Act, as amended. That transmission is a formal but early step in the approximately 2-year process of analysis and consultation required for development of a new 5-year OCS oil and gas leasing program. A Notice requesting comments on the Draft Proposed Program also appears in today's Federal Register.

Pursuant to 40 CFR 1501.7, this Notice initiates the scoping process for the EIS. The Department of the Interior hereby solicits information from Federal, State, and local agencies, and the public regarding alternatives and the issues which should be evaluated in the EIS. Respondents are requested to focus their comments on the environmental issues attendant to the proposal as defined in the Draft Proposed Program which appears elsewhere in today's Federal Register, and on alternative leasing schedules and presale processes which should be evaluated in the EIS.

**DATES:** Scoping comments should be received by May 20, 1985.

**ADDRESS:** Scoping comments should be submitted to Daniel Henry, Minerals Management Service, Mail Stop 644, 12203 Sunrise Valley Drive, Reston, Virginia 22091. Hand deliveries to the Department of the Interior may be made to Room 2516, 18th & C Streets, N.W., Washington, D.C. 20240. Envelopes or packages should be marked "Scoping Comments on the Proposed 5-Year Leasing Program EIS."

**FOR FURTHER INFORMATION CONTACT:** Daniel Henry, Branch of Environmental Evaluation, MMS, at (202) 343-6264.

Author: Daniel Henry, Branch of Environmental Evaluation, MMS.

Dated: March 19, 1985.

William D. Bettenberg,

*Director, Minerals Management Service.*

[FR Doc. 85-6916 Filed 3-21-85; 8:45 am]

BILLING CODE 4310-MR-M

**5-Year Outer Continental Shelf Oil and Gas Leasing Program; Development and Request for Comments**

**AGENCY:** Minerals Management Service, Interior.

**ACTION:** Notice of request for comments on the development of a new 5-year Outer Continental Shelf (OCS) Oil and Gas Leasing Program.

**SUMMARY:** Section 18 of the OCS Lands Act, as amended, requires the Secretary of the Interior to solicit suggestions from Federal Agencies, coastal States, and others during the preparation of a new 5-Year OCS Oil and Gas Leasing Program. The current leasing program, approved in July 1982, schedules lease sales through mid-1987. The Minerals Management Service intends to prepare a program for the period mid-1988 to mid-1991.

**DATES:** Comments and information must be received by August 27, 1984.

**ADDRESS:** Comments and information should be mailed to Deputy Associate Director for Offshore Leasing, Minerals Management Service (MS-641), 12203 Sunrise Valley Drive, Reston, Virginia 22091. Hand deliveries to the Department of the Interior may be made at 18th & C Streets NW., Room 2509, Washington, DC. Envelopes or packages should be marked "Comments on the 5-Year OCS Oil and Gas Leasing Program."

**FOR FURTHER INFORMATION CONTACT:** Telephone contact may be made with Paul R. Stang, (202) 343-1072, for information on the development of a new 5-Year leasing program.

**Author**

William J. Quinn, Offshore Leasing Management Division, Minerals Management Service, 12203 Sunrise Valley Drive, Reston, Virginia 22091.

**SUPPLEMENTARY INFORMATION:** Comments are requested from States, local governments, the oil and gas industry, Federal Agencies, and other interested individuals and groups to assist the Department of the Interior in the preparation of a 5-Year OCS Oil and Gas Leasing Program to cover the period mid-1986 to mid-1991. The program preparation effort now underway is expected to take about 2 years to complete. Approval of the new program in mid-1986 will help provide a smooth transition from the current to the new schedule.

The OCS leasing program schedule enables the Federal Government, affected States, industry, and other interested parties to plan for the steps leading to the offshore lease sales. A decision on whether to proceed with a specific sale on the schedule will be made only after all the applicable requirements of the OCS Lands Act (hereafter called the Act), National Environmental Policy Act (NEPA) of 1969, and other statutes have been met.

The program preparation process will follow all the procedural steps set out in section 18 of the Act. The purpose of this Notice is to solicit comments early in the program preparation process pursuant to section 18(c)(1) of the Act.

Your comments will be considered in the analysis required by section 18(a) of the Act. Once this analysis is completed, alternatives to the proposal will be developed which will include a range of schedules varying the timing or location of proposed offshore lease sales.

A draft proposed program will be prepared based on the section 18(a) analysis. The draft proposed program will display planning milestones and will refer to sales by name and number. Respondents should be aware that the following concepts will be considered in its development:

1. Both quantitative and qualitative information will be considered in meeting the requirements of section 18(a) of the Act;

2. Leasing activities under the program should assure receipt of fair market value for the lands leased (this is a statutory requirement of section 18(a)(4) of the Act);

3. A more flexible approach to leasing decisions will be considered for those planning areas in which the demand for additional leasing in the 1986–1991 period is expected to be limited but could be substantially increased by unexpected events.

The list of planning areas with boundaries described in Table 1 is open to comment. These areas will be subject to analysis under section 18 and will be considered as candidates for the draft proposed program. There are 18 such planning areas which are described in the current 5-year leasing schedule. Note also that the list includes planning areas which do not appear on the approved current schedule. These are: Hope Basin, St. Matthew-Hall, Aleutian Basin, Bowers Basin, Aleutian Arc, and Washington-Oregon. Note that the names of Diapir Field and Barrow Arch have been changed to Beaufort Sea and Chukchi Sea, respectively.

Precise marine boundaries between the United States and opposite or adjacent nations have not been determined in all cases. The maritime boundaries and limits depicted in Table 1 and the attached maps, as well as divisions between planning areas where shown, are for initial planning purposes only. These limits shall not affect or prejudice in any manner the position of the United States with respect to the nature or extent of the internal waters, of the territorial sea, of the high seas, or of soverign rights or jurisdiction for any purpose whatsoever.

**Information Requested**

Comments are solicited as follows:

Information and comments submitted at this stage should be general or conceptual in nature and relevant to determining the appropriate overall size, timing, and location of sales to be considered in the leasing schedule. Data and information which support these general views are also requested. As required by section 18(c)(1) of the Act, any suggestions from the executive of any affected local government in an affected State shall be first submitted to the Governor of such State.

A. As noted above, the Secretary is required by section 18(a) of the Act ot consider a number of factors in formulating a 5-year leasing program. We would like to have information and your suggestions relevent to the requirements of section 18(a). The following list provides an indication of the kind of information which would be most useful in conducting the section 18(a) analysis. Please note that not all factors may be relevant to all wishing to comment.

(1) Information on the economic, social, and environmental values of the renewable and nonrenewable resources contained in the OCS and the potential impact of oil and gas exploration on other resource values of the OCS and the marine, coastal, and human environments.

(2) Existing information concerning geographical, geological, and ecological characteristics of the regions of the OCS and nearshore eyironments.

(3) Suggested methods and information for analyzing the sharing of developmental benefits and environmental risks among the various regions (planning areas) and ways to determine what constitutes an equitable sharing.

(4) Other uses of the sea and seabed, including fisheries, navigation, existing or proposed sealanes, potential sites of deepwater ports, and other anticipated uses of the resources and space of the OCS.

(5) Methods and information for assessing relative environmental sensitivity and marine productivity of the different planning areas of the OCS.

(6) Relevant environmental and predictive information pertinent to offshore and coastal areas potentially affected by OCS developement.

(7) The location of planning areas with respect to, and the relative needs of, regional and national energy markets.

We would also like to have information on the availability of transportation networks to bring oil and gas supplies to demand areas, both on a current and projected basis.

B. Industry respondents are asked to address the following information needs in some detail. It should be emphasized that this information will be used to identify areas of potential for oil and gas development. When weighed against comments on possible environmental effects and the results of various environmental and other cost analyses, these expressions of interest play an important role in the section 18 balancing which ultimately determines the size, timing, and location of sales included in the 5-year program.

The following information is requested with respect to the OCS planning areas:

(1) Ranking of planning areas by order of oil and gas potential. To allow comparisons of responses in a consistent format, we ask that a single list be submitted showing areas ranked 1 through 24.

(2) Ranking of planning areas by order of interest in exploration and development, including reasons for any possible differences in this ranking compared to that in item (1); and

(3) Technological feasibility of conducting exploration and development within specified time periods for each planning area or, if appropriate, for specified portions of each planning area.

C. Suggestions are requested for possible revisions in the planning area boundaries described earlier in this Notice, with reasons for any such revisions.

D. Our information and knowledge of the oil and gas resources of the OCS will be more advanced in 1986 compared to 1982 when the current 5-year program was approved. We believe it may be appropriate to examine ways to help assure that we can accommodate this additional information when the new program begins and adjust the program as further knowledge of the OCS resources and national energy needs evolves. Hence, suggestions are also requested for changes in the leasing process which will allow for a more flexible program while still identifying location and timing as precisely as possible for planning purposes.

Dated: June 14, 1984.

Wm. D. Bettenberg,

*Director, Minerals Management Service.*

Dated: July 5, 1984.

Approved:

William Clark,

*Secretary.*



**Table 1—Description of Planning Areas**

1. *North Atlantic:* Lies offshore of the New England States and is bounded on the west by 71° W. longitude and on the south by approximately 30° N latitude.

2. *Mid-Atlantic:* Extends north from approximately 35° N. latitude along the coast to the intersection of 71° W. longitude thence south along 71° W. longitude to approximately 39° N. latitude, thence east along the 39th parallel.

3. *South Atlantic:* Lies offshore of the States of North Carolina, South Carolina, Georgia, and Florida and is bounded on the north by approximately 35° N. latitude.

4. *Eastern Gulf of Mexico:* Lies offshore of Florida and is bounded on the west by approximately 88° W. longitude and on the north and east by Florida.

5. *Central Gulf of Mexico:* Lies south of Louisiana, Mississippi, and Alabama and is bounded on the east by approximately 88° W. longitude. Its western boundary begins at the offshore boundary between Texas and Louisiana and proceeds southeasterly to approximately 28° N. latitude and 93° 30′ W. longitude, thence east to approximately 92° W. longitude, and thence south.

6. *Western Gulf of Mexico:* Lies south and east of Texas. It is bounded on the east by the extension of the boundary between Texas and Louisiana and proceeds southeasterly to approximately 28° N. latitude and 93° 30′ W. longitude, thence east to approximately 92° W. longitude, and thence south.

7. *Southern California:* Bounded on the north by approximately 34° 30′ N. latitude and on the south by the U.S.-Mexico provisional boundary.

8. *Central and Northern California:* Bounded on the south by approximately 34° 30′ N. latitude and on the north by approximately 42° N. latitude.

9. *Washington-Oregon:* Lies offshore of these two States and is bounded on the south by approximately 42° N. latitude and on the north by approximately 48° 30′ N. latitude.

10. *Gulf of Alaska:* It is bounded approximately on the west by 151° 55′ W. longitude, thence east along 59° N. latitude to 148° W. longitude, thence south to 58° N. latitude, thence east along 58° N. latitude to 147° W. longitude, thence south.

11. *Kodiak:* Lies generally southeast of Kodiak Island. It is bounded on the west by 156° W. longitude. From 156° W. longitude, it extends east along 57° N. latitude, thence northeast to 59° N. latitude, thence to 148° W. longitude, thence south to 58° N. latitude, thence east to 147° W. longitude, thence south.

12. *Cook Inlet:* Lies east of 156° W. longitude and north of 57° N. latitude to the Federal/State boundary south of Kalgin Island.

13. *Shumagin:* Lies southeast of the Alaskan Peninsula. It is bounded on the west by 165° W. longitude, on the east by 156° W. longitude, and on the north by 57° N. latitude.

14. *Aleutian Arc:* Bounded on the east by 165° W. longitude south of the Aleutian Islands chain, 171° W. longitude north of the Aleutian Islands chain, and on the north by 53° N. latitude thence west to 174° E. longitude thence north to 54° N. latitude thence west.

15. *North Aleutian Basin:* Lies in the eastern Bering Sea northwest of the Alaskan Peninsula and south of 59° N. latitude. It is bounded on the west by 165° W. longitude.

16. *St. George Basin:* Lies in the eastern Bering Sea northwest of the Aleutian Islands chain and is bounded on the north by 59° N. latitude and on the west by 174° W. longitude from 59° N. latitude to 58° N. latitude, thence east to 171° W. longitude, thence south. It is bounded on the east by 165° W. longitude.

17. *Bower Basin:* Lies in the Bering Sea north of the Aleutian Islands chain. It is bounded on the north by 56° N. latitude, on the east by 171° W. longitude, on the south by 53° N. latitude west to 174° E. longitude, thence north to 54° N. latitude, thence west.

18. *Aleutian Basin:* Lies in the Bering Sea north of the Bowers Basin area. It is bounded on the south by 56° N. latitude, and on the east by 174° W. longitude from 56° N. latitude to 58° N. latitude, thence west to 180° W. longitude, thence north.

19. *Navarin Basin:* Lies in the western Bering Sea west of St. Matthew Island and south of 63° N. latitude. It is bounded on the northwest by the U.S.-Russia Convention Line of 1867, on the

east by 174° W. longitude, on the west by 180° W. longitude, and on the south by 58° N. latitude.

20. *St. Matthew-Hall:* Bounded on the north by 63° N. latitude, on the west by 174° W. longitude, and on the south by 59° N. latitude.

21. *Norton Basin:* Lies south and southwest of the Seward Peninsula. It is bounded on the south by 63° N. latitude, on the west by the U.S. - Russia Convention Line of 1867, and on the north by 65° 34' N. latitude.

22. *Hope Basin:* Lies north of the Seward Peninsula and is bounded on the west by the U.S. - Russia Convention Line of 1867, on the north by 68° 17' N. latitude and on the south by 65° 34' N. latitude.

23. *Chukchi Sea:* Bounded on the south by 68° 17' N. latitude, on the west by the U.S. - Russia Convention Line of 1867. The northern boundary extends west along 71° N. latitude from the state territorial sea to 182° W. longitude, thence north from this juncture along 162° W. longitude.

24. *Beaufort Sea:* Lies offshore of Alaska in the Beaufort Sea and the Arctic Ocean. It is bounded on the west by the Chukchi Sea planning area and extends eastward to the limit of U.S. jurisdiction.

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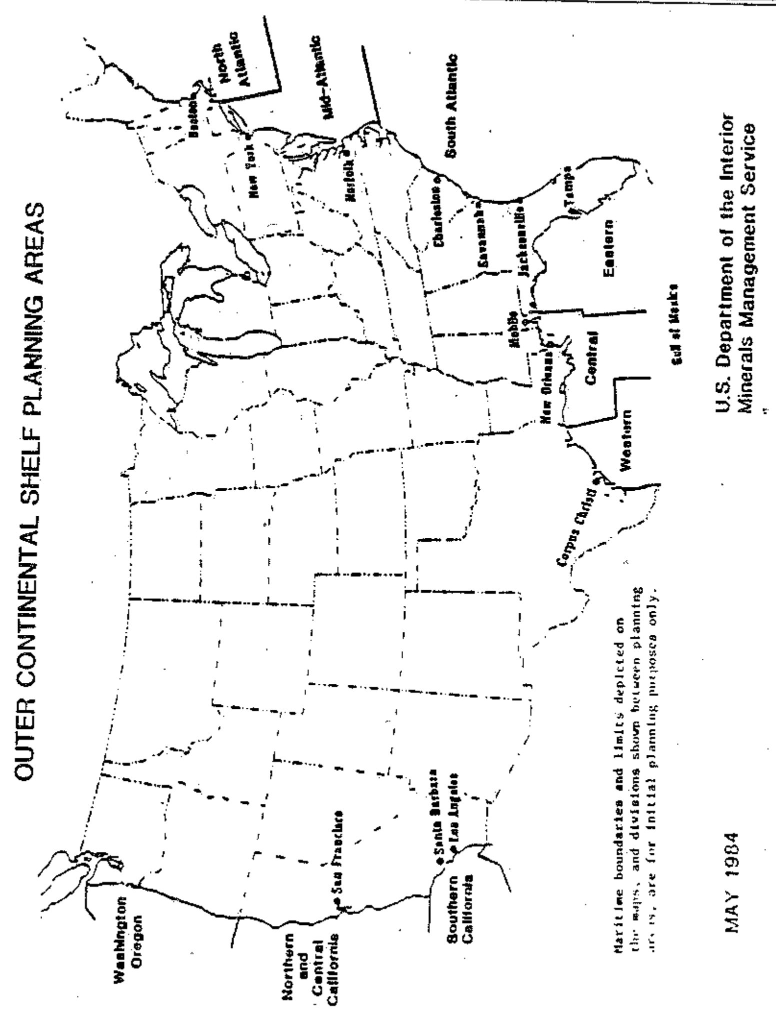

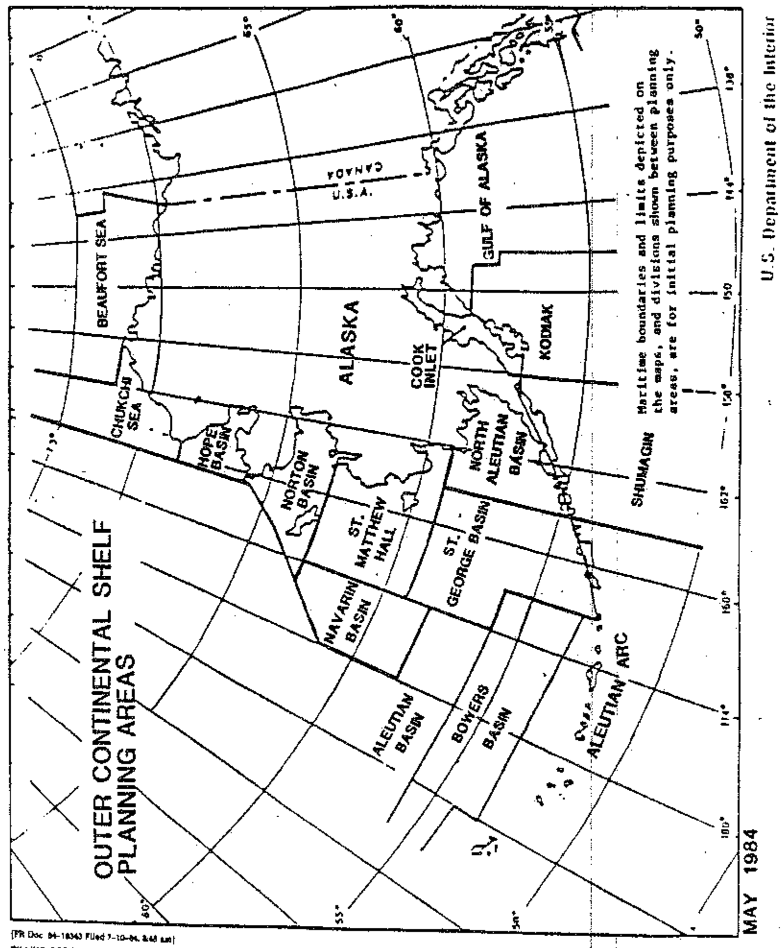


[FR Doc. 84-18343 Filed 7-10-84; 8:45 am]
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# APPENDIX N

# PLANNING AREA BOUNDARIES

## Planning Area Boundaries of the Outer Continental Shelf (OCS) /1

1. North Atlantic: South from the juncture of the SLA limit /2 at approximately 71° W longitude to approximately 39° N latitude thence east to 64°03'05" W longitude thence north to 39°58'39" N latitude at 64°04'05" W longitude thence west to 39°57'04" N latitude at 65°41'49" W longitude thence north to the intersection with the U.S.-Canada Maritime Boundary at approximately 40°28'24" N latitude at 65°43'04" W longitude thence north along the maritime boundary to the SLA limit thence following the SLA limit to the point of origin.

2. Mid-Atlantic: East from the juncture of the SLA limit at approximately 35° N latitude to 70° W longitude thence north to approximately 37° N latitude thence east to 68° W longitude thence north to approximately 38° N latitude thence east to 66° W longitude thence north to 39° N latitude thence west to 71° W longitude thence north to the SLA limit thence along the SLA limit to the point of origin.

3. South Atlantic: East from the juncture of the SLA limit at approximately 35° N latitude to 70° W longitude thence south to approximately 34° N latitude thence west to 72° W longitude thence south to approximately 32° N latitude thence west to 74° W longitude thence south to approximately 31° N latitude thence west to 76° W longitude thence south to approximately 29° N latitude thence west to 78° W longitude thence south to 28°17'10" N latitude thence west to the SLA limit thence north along to the point of origin.

4. Straits of Florida: East from the juncture of the SLA limit at 28°17'10" N latitude to 79°11'24" W longitude thence in a southerly direction along the line of U.S. jurisdiction to approximately 81°13' W longitude at 23°55' N latitude thence west to 83°W longitude thence north to the SLA limit (three league line) south of the Dry Tortugas at approximately 24°28'30" N latitude thence north and east along the SLA limit (three league line) to approximately 24°35' at approximately 82°39'15" thence east to the limits of the territorial sea at the SLA limit (three mile line) thence along the SLA limit to the point of origin.

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/1 These planning area descriptions delineate the outer boundaries of the OCS planning areas. These planning area boundaries are for planning purposes only and should have no application or effect whatsoever as to the possible extent of present or future U.S. jurisdictional claims. Subarea deferral candidates and other areal alternatives to leasing under consideration for this Proposed Final Program are discussed in detail and depicted on maps in the Subarea Attachment to the SID.

/2 The inner limit of the planning areas is a line coterminous with the seaward boundary of each of the coastal States pursuant to the Submerged Lands Act U.S.C. 1301 et sec. For convenience, this limit is described as the "SLA limit" in these planning area descriptions.



5. Eastern Gulf of Mexico: South from the SLA limit at approximately 87°45' W longitude to approximately 29° N latitude thence west to 87°53'34" W longitude thence south to 25°39'50" N latitude thence southeast to 25°36' N latitude at 87°02'42" W longitude thence southeast to 25°30' N latitude at 87°00'35" W longitude thence southeast to 25°12'25" N latitude at 86° 33'12" W longitude thence following the U.S.-Cuba Maritime Boundary to approximately 83° W longitude thence north to the three league line south of the Dry Tortugas at approximately 24°28'30" N latitude thence north and east along the three league line to approximately 24°35' at approximately 82°39'15" thence east to the three league line at approximately 82°19'30" thence north and east along the SLA limit to the point of origin.

6. Central Gulf of Mexico: South from the SLA limit at approximately 87°45' W longitude to approximately 29° N latitude thence west to 87°53'34" W longitude thence south to 25°39'50" N latitude thence northwest to 25°41'56.52" N latitude at 88°23'05.54" W longitude thence west along the U.S.-Mexico Maritime Boundary to 25°42'13.05" at 91°05'24.89" W longitude thence southwest to 25°37' N latitude at 91°40'18" W longitude thence northwest to 25°38' N latitude at 91°43'09" W longitude thence northwest to 25°38'32" N latitude at 91°55'14" W longitude thence north to approximately 27°55'N latitude thence generally west to approximately 93°25' W longitude thence northwest to the juncture of the SLA limit at approximately 93°50' W longitude thence east along the SLA limit to the point of origin.

7. Western Gulf of Mexico: East from the SLA limit along the U.S.-Mexico Maritime Boundary to 25°59'48.28" N latitude at 93°26'42.19" W longitude thence southeast to 25°48' N latitude at 93°03'52" W longitude thence southeast to 25°46' N latitude at 92°59'50" W longitude thence southeast to 25°41' N latitude at 92°56'24" W longitude thence southeast to 25°38'32" N latitude at 91°55'14" W longitude thence north to approximately 27°55' N latitude thence generally west to approximately 93°25' W longitude thence northwest to the juncture of the SLA limit at approximately 93°50' W longitude thence along the SLA limit to the point of origin.

8. Southern California: West along a line extending from the SLA limit at approximately 35°47' N latitude to approximately 124° W longitude thence south to approximately 34°58' N latitude thence east to approximately 122° W longitude thence south to approximately 32°55' N latitude thence east to approximately 121°40' W longitude thence south to approximately 32°40' N latitude thence east to approximately 120°20' W longitude thence south to approximately 32°10' N latitude thence east to 120° W longitude thence south to the U.S.-Mexico Maritime Boundary thence along the U.S.-Mexico Maritime Boundary to the SLA limit thence along the SLA limit to the point of origin.

9. Central California: West along a line extending from the SLA limit at approximately 35°47' N latitude to approximately 124° longitude thence north to approximately 37°59' N latitude thence west to approximately 126° W longitude thence north to approximately 38°46' N latitude thence east to the SLA limit thence along the SLA limit to the point of origin.

10. Northern California: West along a line extending from the SLA limit at approximately 38°46' N latitude to approximately 128° W longitude thence north to approximately 42° N latitude thence east to the SLA limit thence along the SLA limit to the point of origin.

11. Washington-Oregon: West along a line extending from the SLA limit at approximately 42° N latitude to 128° W longitude thence north to the limits of U.S. jurisdiction thence northeast along the limits of U.S. jurisdiction to 48°29'37.19" N latitude at 124°43'33.19" W longitude thence due south to the SLA limit thence along the SLA limit to the point of origin.

12. Beaufort Sea: West from 138° W longitude at 72°57' N latitude to 162° W longitude thence south to 71° N latitude thence east to the SLA limit thence east along the SLA limit to the limit of U.S. jurisdiction thence north along the limit of U.S. jurisdiction to 138° W longitude at 72°31'42.5" thence north to the point of origin.

13. Chukchi Sea: East from the U.S.-Russia Convention Line along approximately 73° N latitude to 162° W longitude thence south to 71° N latitude thence east to the limits of the SLA limit thence generally southwest along the SLA limit to approximately 68°20' N latitude at 167° W longitude thence west to the U.S.-Russia Convention Line thence north to the point of origin.

14. Hope Basin: West from the juncture of the SLA limit at 68°20' N latitude to the U.S.-Russia Convention Line thence south along the U.S.-Russia Convention Line to 65°35' N latitude thence east to the limits of the SLA limit thence along the SLA limit to the point of origin.

15. Norton Basin: West from the juncture of 65°35' N latitude at 168°15' W longitude to the U.S.-Russia Convention Line thence generally southwest along that line to approximately 63° N latitude at 175° W longitude thence east to the SLA limit thence along the SLA limit to the point of origin.

16. Navarin Basin: Southwest from the juncture of approximately 63° N latitude at the U.S.-Russia Convention Line along that line to 180° longitude thence south to approximately 58° N latitude thence east to 174° W longitude thence north to approximately 63° N latitude thence west to the point of origin.

17. St. Matthew-Hall /3: West from the limit of the territorial sea at approximately 63° N latitude at 165° W longitude to 174° W longitude thence south to approximately 59° N latitude thence east to the limit of the territorial sea thence following the limit of the territorial sea to the point of origin.

/3 No sales are scheduled in this planning area in the Proposed Final Program.



18. St. George Basin: South from 59° N latitude at 174° W longitude to 56° N latitude thence east to 171° W longitude thence south to approximately 52°35' N latitude thence east to the SLA limit thence following the SLA limit east to approximately 170°30' W longitude at 52°40' N latitude thence east to the SLA limit at approximately 52°46' N latitude thence following the SLA limit to approximately 52°48' N latitude thence east to the SLA limit thence northeast to 165° W longitude thence north to 59° N latitude thence west to the point of origin.

19. North Aleutian Basin: West from 161°52' W longitude at approximately 59° N latitude to 165° W longitude thence south to the intersection with the SLA limit thence following the SLA limit to the point of origin.

20. Shumagin: South from a point at approximately 54°30' N latitude and 165° W longitude to 50° N latitude thence east to 159° W longitude thence north to 51° N latitude thence east to 156°W longitude thence north to 57° N latitude thence west to the SLA limit thence southwest along the SLA limit to the point of origin.

21. Cook Inlet: East from approximately 56°57' N latitude at 156°25' W longitude to the intersection with the SLA limit thence generally northeast along the SLA limit to approximately 152°27' W longitude thence north to the SLA limit thence around the SLA limit to approximately 59° N latitude at 152° W longitude thence north to the SLA limit thence following the SLA limit to the point of origin.

22. Kodiak: East from 57° N latitude at 156° W longitude to the SLA limit thence generally northeast along the SLA limit to approximately 152°27' W longitude thence north to the SLA limit thence around the SLA limit to approximately 59° N latitude thence east to 148° W longitude thence south to 58° N latitude thence east to 147° W longitude thence south to 53° N latitude thence west to 150° W longitude thence south to 52° N latitude thence west to 156° W longitude thence north to the point of origin.

23. Gulf of Alaska: South from approximately 151°55' W longitude at 59°05' N latitude to the SLA limit at approximately 59° N latitude thence east to 148° W longitude thence south to 58° N latitude thence east to 147° W longitude thence south to 53° N latitude thence east to 141° W longitude thence generally northeast along the limit of U.S. jurisdiction to the SLA limit thence along the SLA limit to the point of origin.

24. Aleutian Basin /3: East from the juncture of approximately 56° N latitude at the U.S.-Russia Convention Line to 174° W longitude thence north to approximately 58° N latitude thence west to 180° longitude thence north to the juncture of the U.S.-Russia Convention Line thence along that line to the point of origin.

/3 No sales are scheduled in this planning area in the Proposed Final Program.

25. Bowers Basin /3: East from the juncture of approximately 56° N latitude at the U.S.- Russia Convention line to 171° W longitude thence south to approximately 53° N latitude thence west to 174° E longitude thence north to approximately 54° N latitude thence west to the U.S.-Russia Convention Line thence along that line to the point of origin.

26. Aleutian Arc /3: East from the juncture of the U.S.-Russia Convention Line at approximately 54° N latitude to 174° E longitude thence south to approximately 53° N latitude thence east to 171° W longitude thence south to approximately 52°35' N latitude thence generally east to the SLA limit thence following the SLA limit generally east to approximately 170°30' W longitude at 52°40' N latitude thence generally east to the SLA limit at approximately 52°46'N latitude thence following the SLA limit to approximately 52°48' N latitude thence generally east to the SLA limit thence northeast to 165° W longitude thence south to approximately 50° N latitude thence west to approximately 167° E longitude thence north to the U.S.-Russia Convention Line thence along that line to the point of origin.

/3 No sales are scheduled in this planning area in the Proposed Final Program.

# APPENDIX O

## LEASING DEFERRALS MADE BY SALE IN THE JULY 1982 5-YEAR OCS OIL AND GAS LEASING PROGRAM (JULY 1982 - JANUARY 1987)

# LEASING DEFERRALS MADE BY SALE IN THE JULY 1982 5-YEAR OCS OIL AND GAS LEASING PROGRAM (JULY 1982 - JANUARY 1987)

Since approval of the July 1982 5-Year Outer Continental Shelf (OCS) Oil and Gas Leasing Program, 38 lease sales have undergone some or all of the prelease planning which determines the size, timing, location, terms, and conditions of each sale. Leasing deferrals can be made at various steps in this process to reflect concerns about sale size and location. Many of the sales have been modified by deferrals--the removal of blocks and acreage, for a variety of reasons, from a sale. Some sales have been cancelled. This appendix delineates the deferrals which have occurred from July 1982 through January 1987 in the current leasing program. Table 1 provides a summary of deferrals to date.

The 38 sales addressed here encompass two different approaches to offshore leasing: tract selection and areawide. Table 2 shows that the bulk of leasing deferrals in tract selection sales occurred early in the prelease process, with the primary emphasis on deferrals after the Call for Nominations. Sales conducted under areawide leasing are likely to have deferrals made later or more often throughout the entire prelease planning process. Since Secretary Clark's announcement in January 1984 that early resolution of conflict would be pursued, these deferrals have tended to occur earlier and earlier.

The reasons for deferring blocks from each sale vary, but generally deferrals result from concerns expressed by affected States and by Federal Agencies, principally the Department of Defense (DOD). Problems with disputed Federal/State or international boundaries have also led to deferrals, although the number of blocks involved in these disputes is generally few.

Acreage data and block statistics in this appendix came from the Minerals Management Service (MMS) official sale files and from the records and files in the four MMS regional offices. Table 2 displays the percentage of blocks and acreage deferred at each prelease step for the 38 sales and indicates the general reason for the deferrals. Unusual characteristics of sales are also noted.

A note of caution: the reasons given here for deferrals are intended as general summaries and should not be interpreted as an official MMS or Department of the Interior explanation of those deferrals. Letters, memoranda, and press releases from each sale contain the official reasons for deferral. The summaries presented here do not supersede the official files.



Table 1: Amount of Acreage of Proposed Lease Sale Areas Deferred During Presale Process (July 1982 - January 1987)

| Sale (Area) | Beginning Acreage (in millions) | Total Deferred as of January 1987 (in millions) | Total Acreage Remaining (in millions) | Percent Acreage Deferred |
|---|---|---|---|---|
| RS-2 | 3.50 | 0.36 | 3.14 | 10.38 |
| **Atlantic Region** | | | | |
| 52 (NA) | 16.97 | Cancelled | Cancelled | Cancelled |
| 76 (MA) | 50.10 | 27.40 | 22.67 | 54.69 |
| 78 (SA) | 81.16 | 60.76 | 20.40 | 74.87 |
| 82 (NA) | 60.00 | Cancelled | Cancelled | Cancelled |
| 90 (SA) | 99.10 | Cancelled | Cancelled | Cancelled |
| 111 (MA) | 81.50 | Cancelled | Cancelled | Cancelled |
| **Gulf of Mexico Region** | | | | |
| 69 (GOM) | 134.40 | 133.10 | 1.40 | 99.03 |
| 72 (CGOM) | 38.00 | 0.20 | 37.87 | 0.53 |
| 74 (WGOM) | 33.00 | 0 | 33.00 | 0 |
| 79 (EGOM) | 58.98 | 7.97 | 50.63* | 13.50 |
| 81 (CGOM) | 45.06 | 0.22 | 34.74* | 0.49 |
| 84 (WGOM) | 35.27 | 0.59 | 30.04* | 1.70 |
| 94 (EGOM) | 58.97 | 22.80 | 36.20* | 38.60 |
| 98 (CGOM) | 45.06 | 9.05 | 24.01* | 20.10 |
| 102 (WGOM) | 35.27 | 1.60 | 27.20* | 4.54 |
| 104 (CGOM) | 45.06 | .03 | 31.40 | 0.03 |
| 105 (WGOM) | 35.27 | 0.60 | 34.67 | 1.70 |
| 110 (CGOM) | 31.70 | 0 | 31.70 | 0 |

* Totals do not add because beginning acreage figures include leased blocks which were not withdrawn until the proposed Notice of Sale.

MA = Mid-Atlantic
NA = North Atlantic
SA = South Atlantic

GOM = Gulf of Mexico
CGOM = Central Gulf of Mexico
EGOM = Eastern Gulf of Mexico
WGOM = Western Gulf of Mexico

RS-2 = Reoffering Sale 2

Table 1 (continued): Amount of Acreage of Proposed Lease Sale Areas Deferred During Presale Process (July 1982 - January 1987)

| Sale (Area) | Beginning Acreage (in millions) | Total Deferred as of January 1987 (in millions) | Total Acreage Remaining (in millions) | Percent Acreage Deferred |
|---|---|---|---|---|
| Pacific Region | | | | |
| 73 (CC) | 24.14 | 23.37 | 0.77 | 98.81 |
| 80 (SC) | 22.50 | 19.35 | 3.15 | 86.01 |
| 91 (NC) | 1.20 | 0 | 1.20 | 0 |
| Alaska Region | | | | |
| 57 (NB) | 27.20 | 24.82 | 2.38 | 91.25 |
| 70 (SGB) | 46.00 | 43.31 | 2.69 | 94.15 |
| 71 (BS) | 13.87 | 12.05 | 1.83 | 86.84 |
| 83 (NV) | 37.09 | 9.04 | 28.05 | 24.38 |
| 85 (CS) | 29.45 | Cancelled | Cancelled | Cancelled |
| 86 (SH) | 83.00 | Cancelled | Cancelled | Cancelled |
| 87 (BS) | 49.36 | 41.59 | 7.73 | 84.25 |
| 88 (GA) | 137.68 | Cancelled | Cancelled | Cancelled |
| 89 (SGB) | 70.24 | Cancelled | Cancelled | Cancelled |
| 92 (NAB) | 32.45 | 26.85 | 5.60 | 82.73 |
| 97 (BS) | 52.00 | 31.00 | 21.00 | 59.62 |
| 99 (KO) | Cancelled | Cancelled | Cancelled | Cancelled |
| 100 (NB) | 19.20 | Cancelled | Cancelled | Cancelled |
| 107 (NV) | 28.10 | 0 | 28.10 | 0 |
| 109 (CS) | 29.45 | 0 | 29.45 | 0 |

NC = Northern California
CC = Central California
SC = Southern California

BS = Beaufort Sea
CS = Chukchi Sea
GA = Gulf of Alaska/Cook Inlet
KO = Kodiak

NAB = North Aleutian Basin
NB = Norton Basin
NV = Navarin Basin
SGB = St. George Basin
SH = Shumagin



Table 2: Percent Deferred as of January 1987 by Planning Stage for Sales in the July 1982 5-Year OCS Oil and Gas Leasing Schedule

| Sale and Area | | % deferred from Call | % deferred from AID[1] | % deferred from PNS[2] | Total % deferred | Notes |
|---|---|---|---|---|---|---|
| RS-2 | Acres: | NA | 8.7 | 1.8 | 10.4 | b,e |
| | Blocks: | NA | 8.7 | 1.8 | 10.4 | |
| 52: North Atlantic | Acres: | 82.0 | 0 | 9.7 | 100.0 | a,b |
| | Blocks: | 82.2 | 0 | 9.6 | 100.0 | c,h |
| 76: Mid-Atlantic | Acres: | 49.3 | 10.6 | 0.05 | 54.7 | b,c |
| | Blocks: | 48.6 | 10.4 | 0.05 | 54.0 | e,f |
| 78: South Atlantic | Acres: | 59.2 | 0.3 | 38.8 | 74.9 | b,c |
| | Blocks: | 59.2 | 1.7 | 37.4 | 74.9 | e,f |
| 82: North Atlantic | Acres: | 59.2 | 44.9 | 51.9 | 100.0 | b,c,d |
| | Blocks: | 60.1 | 42.7 | 53.9 | 100.0 | e,f,h |
| 90: South Atlantic | Acres: | 58.8 | 69.4 | | 100.0 | c,f |
| | Blocks: | 59.2 | 69.6 | | 100.0 | g,h |
| 111: Mid-Atlantic | Acres: | 75.1 | | | 100.0 | b,c |
| | Blocks: | 73.5 | | | 100.0 | f,h |
| 69[3]: Gulf of Mexico | Acres: | 99.0 | 0 | Part I 0 | 99.0 | a,e |
| | | | | Part II 0.7 | | |
| | Blocks: | 99.0 | 0 | Part I 0 | 99.0 | |
| | | | | Part II 1.5 | | |
| 72: Central Gulf of Mexico | Acres: | 0 | 0.5 | 0 | 0.5 | e |
| | Blocks: | 0 | 0.6 | 0 | 0.6 | |
| 74: Western Gulf of Mexico | Acres: | 0 | 0 | 0 | 0 | |
| | Blocks: | 0 | 0 | 0 | 0 | |

Notes:
a - Deferral made as part of tract selection process.
b - Deferral made at request of a State.
c - Deferral made at request of the DOD/National Aeronautics and Space Administration (NASA).
d - Deferral made by congressional moratoria.
e - Deferral made for administrative reasons (boundary litigation concerns, mapping errors, etc.)
f - Deferral made because only geologically favorable acreage was considered after Call for Information (areawide lease sale).
g - Deferral made by Secretary for other reasons.
h - Sale cancelled.
i - Sale still in prelease planning stages.

1 AID = Area Identification
2 PNS = Proposed Notice of Sale

NA = Not Applicable

Table 2 (continued): Percent Deferred as of January 1987 by Planning Stage for Sales in the July 1982 5-Year OCS Oil and Gas Leasing Schedule

| Sale and Area | | % deferred from Call | % deferred from AID[1] | % deferred from PNS[2] | Total % deferred | Notes |
|---|---|---|---|---|---|---|
| 79: Eastern Gulf of Mexico | Acres: | NA | 0 | 13.5 | 13.5 | c |
| | Blocks: | NA | 0 | 14.4 | 14.4 | |
| 81: Central Gulf of Mexico | Acres: | 0 | 0 | 0.6 | 0.5 | b,d |
| | Blocks: | 0 | 0 | 1.1 | 0.8 | |
| 84: Western Gulf of Mexico | Acres: | 0 | 1.7 | 0 | 1.7 | a,d |
| | Blocks: | 0 | 2.0 | 0 | 2.0 | |
| 94: Eastern Gulf of Mexico | Acres: | 0 | 33.9 | 2.2 | 8.6 | a,e, |
| | Blocks: | 0 | 33.6 | 2.8 | 39.6 | g |
| 98: Central Gulf of Mexico | Acres: | 0 | 0 | 27.4 | 20.1 | d,e,g |
| | Blocks: | 0 | 0 | 26.3 | 19.0 | |
| 102: Western Gulf of Mexico | Acres: | 0.03 | 1.7 | 3.5 | 4.5 | a,d,g |
| | Blocks: | 0.03 | 1.9 | 3.5 | 4.7 | |
| 104: Central Gulf of Mexico | Acres: | 0 | 0 | 0.03 | 0.03 | d |
| | Blocks: | 0 | 0 | 0.03 | 0.03 | |
| 105: Western Gulf of Mexico | Acres: | 1.7 | 0 | 0 | 1.7 | |
| | Blocks: | 2.0 | 0 | 0 | 2.0 | e |
| 110: Central Gulf of Mexico | Acres: | 0 | 0 | 0 | | f |
| | Blocks: | 0 | 0 | 0 | | |

Notes:
a - Deferral made at request of a State.
b - Deferral made at request of the DOD/NASA.
c - Deferral made by congressional moratoria.
d - Deferral made for administrative reasons (boundary litigation concerns, mapping errors, etc.)
e - Deferral made by Secretary for other reasons.
f - Sale still in prelease planning stages.
g - Deferral included deepwater acreage.

1 AID = Area Identification
2 PNS = Proposed Notice of Sale

NA = Not Applicable



Table 2 (continued): Percent Deferred as of January 1987 by Planning Stage for Sales in the July 1982 5-Year OCS Oil and Gas Leasing Schedule

| Sale and Area | | % deferred from Call | % deferred from AID[1] | % deferred from PNS[2] | Total % deferred | Notes |
|---|---|---|---|---|---|---|
| 73[3]: Central California | Acres: | 62.0 | 81.5 | 54.7 | 96.8 | a,b |
| | Blocks: | 62.6 | 83.1 | 51.6 | 96.9 | c,d,e |
| 80: Southern California | Acres: | 48.4 | 66.4 | 23.1 | 86.0 | b,c,d |
| | Blocks: | 46.6 | 69.2 | 46.4 | 84.3 | e,f |
| 57: Norton Basin | Acres: | 91.0 | 0 | 2.6 | 91.3 | a,b |
| | Blocks: | 90.9 | 0 | 2.6 | 91.1 | |
| 91: Northern California | Acres: | 96.0 | | | | h,i |
| | Blocks: | 96.0 | | | | |
| 70: St. George Basin | Acres: | 94.3 | 0 | 0 | 94.2 | a |
| | Blocks: | 94.2 | 0 | 0 | 94.2 | |
| 71: Beaufort Sea | Acres: | 86.8 | 0 | 1.4 | 86.8 | a,e |
| | Blocks: | 84.9 | 0 | 3.4 | 86.3 | |
| 83: Navarin Basin | Acres: | 20.3 | 4.7 | 0.2 | 24.4 | c,f |
| | Blocks: | 20.5 | 4.7 | 0.2 | 24.4 | |
| 85: Chukchi Sea | Acres: | 0 | | | 100.0 | g |
| | Blocks: | 0 | | | 100.0 | |
| 86: Shumagin | Acres: | 0 | | | 100.0 | g |
| | Blocks: | 0 | | | 100.0 | |
| 87: Beaufort Sea | Acres: | 63.5 | 55.8 | 2.5 | 84.3 | b,f |
| | Blocks: | 62.8 | 54.9 | 2.5 | 83.6 | |

Notes:
a - Deferral made as part of tract selection process.
b - Deferral made at request of a State.
c - Deferral made at request of the DOD/NASA.
d - Deferral made by congressional moratoria.
e - Deferral made for administrative reasons (boundary litigation concerns, mapping errors, etc.)
f - Deferral made because only geologically favorable acreage was considered after Call for Information (areawide lease sale).
g - Sale cancelled or withdrawn from schedule.
h - Sale still in prelease planning stage.
i - Deferral made prior to issuance of Call.

1 AID = Area Identification
2 PNS = Proposed Notice of Sale
3 Sale 73 started as a Tract Selection Sale but was then changed to a (modified) Areawide Sale. It also started as an all California sale and later was changed to Central and Northern California and finally to just Central California.

Table 2 (continued): Percent Deferred as of January 1987 by Planning Stage for Sales in the July 1982 5-Year OCS Oil and Gas Leasing Schedule

| Sale and Area | | % deferred from Call | % deferred from AID[1] | % deferred from PNS[2] | Total % deferred | Notes |
|---|---|---|---|---|---|---|
| 88: Gulf of Alaska/ Cook Inlet | Acres: | 81.4 | 46.3 | | 100.0 | a,b,c |
| | Blocks: | 80.8 | 46.2 | | 100.0 | d,e,f |
| 89: St. George Basin | Acres: | 0 | 7.1 | | 100.0 | |
| | Blocks: | 0 | 8.6 | | 100.0 | b,e,f |
| 92: North Aleutian Basin | Acres: | 82.7 | 0 | 0 | 82.7 | a,d |
| | Blocks: | 83.4 | 0 | 0 | 83.4 | |
| 97: Beaufort Sea | Acres: | 59.6 | | | | c,e |
| | Blocks: | 56.3 | | | | |
| 99: Kodiak | Acres: | | | | 100.0 | f |
| | Blocks: | | | | 100.0 | |
| 100: Norton Basin | Acres: | 49.0 | | | 100.0 | a,c,f |
| | Blocks: | 51.5 | | | 100.0 | |
| 107: Navarin Basin | Acres: | 0 | | | | e |
| | Blocks: | 0 | | | | |
| 109: Chukchi | Acres: | 0 | | | | |
| | Blocks: | 0 | | | | e |

Notes:
a - Deferral made at request of a State.
b - Deferral made for administrative reasons (boundary litigation concerns, mapping errors, etc.)
c - Deferral made because only geologically favorable acreage was considered after Call for Information (areawide lease sale).
d - Deferral made by Secretary for other reasons.
e - Sale still in prelease planning stages.
f - Sale has been cancelled.

[1] AID = Area Identification
[2] PNS = Proposed Notice of Sale

ANALYSIS OF THE PACE OF LEASING AND DEVELOPMENT

CONTENTS



ILLUSTRATIONS



TABLES

## Executive Summary

The change in 1983 from smaller tract selection OCS lease sales to areawide sales caused considerable controversy on several grounds. Although sale procedures were modified in 1984 and 1985 to focus sales on promising acreage, substantial acreage was still offered in some areas and controversy over the pace of leasing continued. In a report published in July 1985, the General Accounting Office (GAO) concluded that areawide leasing had increased the pace of exploration but had reduced competition and bonuses. It recommended that the Secretary consider such effects in relation to anticipated benefits. This appendix analyzes those aspects of the pace of leasing concerning investment, economic benefits, fair market value and revenues. It evaluates the extent to which experience with areawide leasing has achieved its objectives and borne out the concerns expressed about its effects. It also discusses the implications for the new 5-year leasing program.

The most important conclusions from this analysis are that the larger sales typical of areawide and focused leasing have caused:

- substantial increases in the investments in leasing and exploration needed to reap the energy and economic benefits of OCS resources;
- a substantial increase in the benefits to the U.S. economy that can be expected to result from development of OCS oil and gas;
- a substantial increase, perhaps more than $7.5 million per tract, in the total return to the U. S. Treasury from leasing in the Central and Western Gulf of Mexico; and
- at most, a relatively small part of the total decline in bonuses observed in leasing during 1983 through 1985.

Areawide and focused leasing were most effective in increasing investment in areas with proven oil and gas deposits and in areas where the marginal probability of finding hydrocarbons is high. Focused leasing, because it narrows lease sales to such areas, is expected to yield most of the economic benefits of areawide leasing.

Central to the analysis is the concept of the OCS lands as an inventory of investment opportunities that can yield varying returns and economic benefits. An analytic framework is developed which accounts for changes in the inventory of unleased tracts that can occur as a result of changing economic conditions (particularly oil price expectations), changing geologic knowledge, and the different leasing rates that can occur. The status of the inventory depends not only on the economic and geologic conditions that make prospects valuable, but on the way in which tracts have been sold from the inventory in previous years. Changes in the Government's inventory of unleased tracts are reflected in changes in the characteristics of the tracts sold in subsequent sales. Thus, as sales proceed, the amount of acreage leased, its value, the cash bonus revenue collected by the Government and the subsequent level of investment in exploration and the resulting economic benefits would be expected to change as the nature of the unleased inventory changed.



Two key objectives of areawide and focused leasing were to expand the amount and location of acreage leased and to increase the rate of investment in exploration. Critics expressed related concerns that industry did not have the capital to expand its investment and that leases would be acquired, but not explored or developed until years later. This appendix examines data on the experience under tract selection sales in the 1976-1982 period compared with the larger sales of the 1983-1985 period. It shows that during the 1976-1982 period, OCS leasing and investment in exploration did not expand much as price increases made more tracts attractive for investment. As a result, the Government's inventory of unleased acreage worth investing in grew in size and value. Areawide and focused lease sales in 1983 through 1985 substantially increased industry's investment in lease acquisition and exploration, particularly in the Gulf of Mexico. Unfortunately, these gains in the rate of investment in exploration have been severely undercut by the industry-wide exploration cutbacks caused by the 1986 oil price drop. The acreage leased in 1983 through 1985 can provide the basis for a rapid growth in exploration should oil prices rebound to their 1985 levels during the next 2 to 5 years. If oil prices do not rebound, much of this acreage will be returned to the Government's inventory and will be available to be leased when price expectations warrant.

The different rates of investment in exploration that can occur under different approaches to leasing can be expected to result in different benefits to the economy. Earlier exploration can be expected to be followed by earlier discovery of those oil and gas deposits that are economic to produce. Earlier production and realization of the economic benefits from less costly domestic oil and gas production follow. This appendix analyzes the effects of different leasing rates on the timing and value of the benefits to the economy. A comparison is made for oil and gas resources in the Gulf of Mexico between a rate of leasing typical of the 1982 5-Year Leasing Program and the proposed 1987 program on the one hand and continued leasing at a slower rate typical of tract selection procedures used until 1983 on the other. The more rapid scenario yields gains of $8 billion to over $40 billion in total economic benefits derived from development of these oil and gas resources.

The buildup of the inventory in the 1976-1982 period and its drawdown in 1983-1985 also had important revenue consequences. Critics of areawide leasing charged that competition would be so thinned by offering much more acreage that bonus bids would decline and the fair market value requirement of Sec. 18(a)(4) would be violated. The GAO estimated that the decline in bonuses caused by areawide leasing was $3.1 million per tract, accounting for about 20 percent of the total observed decline. The statistical analysis supporting this estimate is reviewed in this appendix. Numerous weaknesses are found which undermine confidence that the estimates correctly measure the bonus effect of areawide leasing.

This appendix shows that the restricted leasing in tract selection sales of the 1976-1980 period increased average bonus bids per acre, primarily by withholding tracts from sale while their value appreciated. Total revenues from bonuses in that period were limited because of the limited amount of acreage leased. In contrast, areawide and focused leasing in 1983, 1984 and 1985 drew down the inventory rapidly. This accelerated leasing resulted in receiving revenues much earlier than would have been the case under tract selection procedures. Bonuses have been received in the 1983-1985 period that would otherwise have been spread out over the 1983-1994 period. As it turns out, the bonus revenues received for tracts leased in the 1983-1985 period are much higher than they would be if they were leased during the period when oil price expectations are depressed by OPEC's "price war" strategy.

Ultimately, royalties and taxes will also be received earlier because earlier leasing leads to earlier production. This appendix estimates that under the actual leasing rates in the Central and Western Gulf of Mexico in 1983 and 1984, bonuses would have to be higher, perhaps by more than $7.5 million per tract, under the leasing rates typical of tract selection procedures to yield the same present value of revenues as will be realized by the Federal Government from areawide and focused lease sales in those areas. Thus, even if the GAO estimate of a $3.1 million decline in average bonuses were correct, the Treasury would still come out ahead in the long run.

Critics of a faster pace of leasing charged that it would thin competition by spreading a limited number of bidders and their limited capital over far more acreage. Less competition, they claimed, would mean lower bids and violation of the fair market value requirement of Sec. 18(a)(4) of the OCS Lands Act. The Secretary and the Courts recognized in 1982 that bonuses might decline under areawide leasing. The Court rejected the claim that this meant a violation of the fair market value requirement. Nevertheless, the relationship between the pace of leasing, the number of bids and the amount paid in bonuses remains a matter of controversy.

The draw down in the inventory resulted in decreasing average bids although total revenues from bonuses increased, particularly in 1983. Fewer high value tracts and more low value tracts were leased in subsequent sales. The trend of decreasing average bids began, however, in 1980, well before the start of areawide leasing. This appendix concludes that such variations in the average bid do not indicate a violation of the fair market value requirement. This provision does not require the Secretary to maximize bonus revenues by withholding tracts while their value appreciates. In addition, the values of many tracts were decreasing during the 1983-1985 period because of declining oil price expectations.

This appendix shows that the average number of bids per tract declined during the 1980-1984 period as average bids declined. The percentage of tracts receiving one bid increased while the percentage receiving two or more bids decreased. These trends began before the implementation of areawide leasing and continued in areawide and focused lease sales. In addition, the sixfold increase in the minimum bid implemented in 1982 would be expected to lead to somewhat fewer bids per tract, on average. It is difficult, however, to



isolate the effects of fewer bids on the bid levels from the effects of declining tract values on the number of bids. Since average bids declined more on tracts receiving more than two bids than on tracts receiving only one or two bids, it is reasonable to conclude that most of the decline in average bids was caused by factors other than competition.

Using the inventory concept, this appendix shows that if oil prices are expected to be stable and past areawide leasing has drawn down the inventory of unleased acreage, then areawide, focused and tract selection procedures could cause similar types and amounts of acreage to be leased in future sales. The patterns of competition, the levels of bids and the implications for meeting the fair market value requirement would also be similar. If oil prices decline sharply as they did in 1986, the pace of leasing would decline regardless of the amount of acreage offered. Only the best unleased prospects offer sufficient returns at low prices to be worth leasing in times of reduced earnings in the oil industry.

If oil prices and price expectations rise, however, tract selection procedures would yield different results than focused or areawide sales. If tract selection sales withheld leasable tracts while tract values were appreciating, three developments would result: (1) Competition would tend to increase as the value of tracts offered rose; (2) average bonuses would increase as the value of the unleased inventory appreciated; and (3) the delayed leasing and investment in exploration caused by holding tracts in the inventory as they appreciated would, in general, reduce the benefits to the economy in comparison with more rapid leasing and investment. Areawide and focusing-on-promising acreage procedures, on the other hand, would allow less appreciation in tract values before they drew bids and thus would cause a smaller increase in the number of bidders. Average bonuses would increase less, but the rate of investment would be greater. This could be expected to yield greater total revenues to the Treasury and greater benefits to the U.S. economy.

# APPENDIX P

## ANALYSIS OF THE PACE OF LEASING AND DEVELOPMENT

### Effects on Investments, Economic Benefits, Revenue and Fair Market Value

## ANALYSIS OF THE PACE OF LEASING AND DEVELOPMENT

### Effects on Investments, Economic Benefits, Revenue and Fair Market Value

### I. Introduction

The pace of leasing for OCS oil and gas has been a matter of controversy for over a decade, focusing on the size of lease sales and their frequency. Debates arose in 1974 when the Government proposed to lease 10 million acres a year in response to OPEC oil price hikes. The acreage actually leased, using Interior's tract selection procedures, did not exceed 2 million acres per year until 1981, the second year of the leasing program approved in 1980. Further controversy arose over the areawide leasing program approved in 1982. Under this program 6.6 million acres were leased in 1983. In 1984, 8.2 million acres were leased, in 1985, 3.4 million, and in 1986, 0.7 million.

The objective of areawide leasing was to allow the private sector a wider choice in the location and the rate of investments in exploration and development of OCS oil and gas prospects. A procedural change was made in order to achieve this objective, allowing the higher leasing rates of 1983 and 1984. The tract selection sale procedures used in prior years had restricted the location and the amount of acreage offered. For tract selection sales, tract value estimates were prepared for all tracts to be offered and were completed prior to the date of the sale. As a result of such administrative constraint, less than half of the tracts nominated by potential bidders were offered in the subsequent sale. The tracts selected from those nominated tended to be those that received nominations from more firms.

The removal of such administrative constraints on the size of lease sales allowed decisions on the acreage to be offered in specific lease sales to be focused on the potential for oil and gas discovery and its benefits on one hand and the potential environmental effects on the other. In particular, it allowed tracts to be offered even though they had modest potential so long as the environmental risks were judged to be in reasonable balance. Firms were not prevented from investing in lease acquisition and exploration in areas for which they had developed unique information about the resource potential unless there was judged to be a substantial environmental risk.

In January, 1984, and again in March, 1985, the areawide sale procedures were modified to provide for earlier consultation concerning, and resolution of, conflicts over the acreage to be offered in a sale. The resulting procedures are intended to identify promising acreage while removing acreage that has little oil and gas potential or high conflict with other resources and uses. In general, the procedures to focus on promising acreage result in the offering of less acreage.

Most of the controversy over the pace of OCS leasing stems from the fear of extensive environmental damage and onshore impacts. The debate, however, has expanded to include a wide range of issues, among them the danger of premature development and the need to conserve resources for future generations, the potential effects of capital limitations on the pace and efficiency of exploration and development, the effect of large lease offerings on the



competitive lease sale process and its ability to yield appropriate revenues to the Federal Government, and the administrative work load, particularly in State and local governments, necessitated by larger and more frequent sales.

On July 15, 1985 the General Accounting Office (GAO) issued a report entitled "Early Assessment of Interior's Area-Wide Program For Leasing Offshore Lands." This report evaluated the effects of areawide leasing on the amount of acreage leased, exploration activity, bidding competition and bonus revenues. It also examined the presale planning and public participation processes and the bid acceptance procedures used in areawide leasing. The GAO concluded, in particular, that areawide leasing had sharply increased the pace of exploration and reduced competition and bonus bids. It recommended "that the Secretary of the Interior consider the effects [of areawide leasing and other approaches] on competition and bid revenues in relation to anticipated benefits, and report his findings to the Congress."

This appendix focuses primarily on the investment, economic and revenue aspects of the pace of leasing issue. The question of timing of investments, which is fundamental to economically efficient development of OCS oil and gas deposits, is discussed in Appendix F. As part of the analysis of economic benefits, Appendix F develops economic principles for sequencing development and guidelines for formulating leasing programs that deal with the problems of premature and tardy investments. Appendix P develops additional concepts used to analyze the effects of the pace of leasing on investments and resulting economic benefits as well as on competition and revenues.

This appendix begins, in Section II, by developing a framework for assessing the consequences of different leasing rates for investments and economic benefits. It draws on Appendix F for concepts of the relationship between the timing of investments and resulting economic benefits as well as the economic characteristics of OCS oil and gas resources. This framework is intended to assist in the analysis of the experience under tract selection sales of the 1970's and early 1980's and larger sales of 1983 through 1985. More importantly, it will provide a basis for evaluating the possible consequences of leasing at different rates under the conditions likely to prevail in the 1987-1992 period of the third 5-year program.

The third section of this appendix applies this framework to the analysis of the investments in lease acquisition and exploration that have occurred as a result of past leasing. It provides estimates of the differences in economic benefits that are expected to result from different rates of leasing for the Secretary to consider as recommended by the GAO. The analysis shows that more rapid leasing has increased the rate of investment in exploration, particularly in the Gulf of Mexico. A comparison of the economic benefits likely to result with those of a slower leasing program shows gains in the Gulf of Mexico of $8 billion to over $40 billion. Section III also assesses the implications for the effects of future leasing under procedures ranging from areawide to tract selection.

Section IV develops a framework for assessing the effects of the rate of leasing on Federal revenues and fair market value. Issues about fair market value are often stated in the form of a charge that a rapid rate of leasing (such as that in 1983, 1984, and 1985) thins competition and depresses the cash bonus bids made for OCS leases and thus undermines the Secretary's ability to "assure receipt of fair market value" as he is required to do by the OCS Lands Act (Sec. 18(a)(4)). Section V evaluates the evidence regarding such effects including the finding that areawide leasing caused a reduction in bonuses that was provided by the July 1985 GAO report. It is shown that the total value of Government revenues is likely to have been increased by earlier leasing, offsetting any declines in bonuses that may have been due to areawide leasing.

The analysis focuses on two types of comparisons. The results of the areawide and focused-on-promising-acreage lease sales of 1983 through 1985 are compared to the results of tract selection sales in prior years. This analysis shows how the pace of leasing and investment was influenced by sale procedures, world oil prices and previous leasing. In addition, comparisons are made of the likely effects, in the 1987-1992 era, of restricted lease offerings, such as those that resulted from tract selection procedures, and more rapid lease offerings, such as those under areawide or focusing procedures.

## II. A Framework for Assessing Effects on Investments and Economic Benefits

One way to approach the analysis of OCS oil and gas investments and the resulting benefits to the economy is to develop a picture of how investments would be made over an extended period of time if there were no restrictions on OCS leasing and the availability of investment opportunities. If there were no restrictions, environmental damages or adverse onshore impacts and the leasing program operated in a fashion that made acreage available whenever it was seen as a good investment, then the resulting path of investments would reflect the response of oil and gas companies to the conditions that determine the economic attractiveness of OCS prospects. OCS investments would be determined by the same processes that govern investments throughout the economy, including those for oil and gas development on private lands. The economy would benefit from the returns on such OCS investments just as it does from investments in other sectors.

The conditions that affect the payoffs from OCS investments include the economic characteristics of OCS oil and gas deposits, the state of geological and geophysical knowledge, and economic conditions and expectations (particularly regarding future oil and gas prices). As discussed in Appendix F, prospects in which oil and gas may be discovered vary substantially, particularly in those characteristics that affect the cost of finding and producing oil and gas. For a given set of expectations about future prices, a lower cost prospect has higher expected economic benefits and higher payoffs from the investments needed to explore and develop the prospect. Some prospects have costs so high that investments are not worthwhile until prices are expected to be higher or until the chance of finding oil has been increased by additional geological and geophysical knowledge.

If one or both of these developments is expected to proceed as time passes, then the OCS can be described as an inventory of ripening investment opportunities. As time passes, increasing prices or emerging resource knowledge gradually make some prospects more attractive for investment. In general, the lowest cost, most easily found prospects become attractive earliest. (In the case of Gulf of Mexico offshore oil, this occurred in the late 1940s and 1950s.) As time passes, exploration reveals the location of most of the large, low cost deposits. Higher cost prospects become attractive for investment as oil prices increase or technology reduces costs.



In this picture of the OCS, firms are constantly reviewing the prospects for investment so that any major event, such as the OPEC price increases of 1974 or 1979, that rapidly increases the number of good investment opportunities brings forth a period of greater investment until the freshly ripened opportunities have all been harvested. Similarly, when events reduce the attractiveness of the remaining OCS investment opportunities, the rate of investment is reduced.

In actuality, of course, a variety of administrative, political and legal restrictions have been placed on the availability of OCS prospects for investment. Setting aside the question of whether such restrictions are warranted because of the potential environmental and onshore effects of OCS oil and gas development, it is possible to examine their consequences for investment.

If OCS tracts are not available for leasing and investment when they become attractive, the inventory of unleased acreage will come to contain more good prospects and their value will increase. (As Appendix F shows, most gains of this type are not sufficient to warrant the delays in investment.) The more restrictive the leasing program, and the longer the period of restriction while oil prices and price expectations increase and geological knowledge of good prospects evolves, the greater would become the number and the value of unleased prospects attractive for investment. Many unleased tracts would have costs substantially less than those of the most costly tracts that were economic to develop at that time. Leasing of the better tracts from such an inventory would tend to yield relatively high bids.

Once a sizable inventory of valuable unleased prospects has accumulated, the rates of leasing and investment that could result from unrestricted access are substantial, at least until the inventory has been drawn down. Any institutional rigidities in the capacity to expand investments would tend to temper the response, stretching the draw-down period over a longer time. Eventually, however, the inventory would be depleted of most of the highly valuable prospects that had become over-ripe for investment. Continued unrestricted leasing would then result in more moderate levels of leasing and exploration with periods of expansion and recession in response to changes in economic conditions and expectations.

It is worth noting that the inventory buildup caused by restrictive leasing in mature areas like the Gulf of Mexico would differ from that in frontier areas. As any area matures by undergoing extensive exploration, the early investments tend to lease and find the relatively few large, low cost deposits. As shown in Appendix F, the resource potential remaining in an area that has undergone substantial exploration tends to be located in more numerous smaller prospects that yield fewer economies of scale. Restriction of leasing in a mature area would thus tend to build up an inventory of many moderate to small prospects along with a few larger prospects at the high cost margins of the area where exploration has not yet occurred. The eventual leasing of this inventory of good prospects could involve substantial acreage, most of it with much lower yield potential than that leased earlier. While some tracts would have substantial value, many more would have modest value.

In contrast, a frontier area, which because of its high cost has not been worth exploration investments until substantial price increases occurred, would tend to build up an inventory of relatively few large prospects if leasing did not make acreage available as soon as it became ripe. The few large prospects could hold the potential for a substantial amount of production from a relatively small amount of acreage. Although such an area may also contain many smaller prospects, costs are so high that even after years of delay in initial leasing, prices may not be sufficient to make them ripe for investment.

Thus, unrestricted leasing after a period of restriction would be expected to yield far different results in a mature area than in a frontier area. In a mature area, the amount of acreage leased and the rate of investment in exploration would tend to be quite substantial. The potential resource yield per acre and its average economic value per acre might be lower than during a period when mostly higher value tracts were offered. In comparison, unrestricted offerings in a frontier area would tend to lease much less acreage, but it would tend to have a high resource yield per acre. Its economic value could be substantial in the largest prospects and moderate in large prospects just ripe for investment.

A significant decline in oil prices and oil price expectations would have an opposite effect. The number of prospects ripe for investment would decrease. At prices sharply lower than previous trends, firms would want to lease only the best unleased prospects with lowest costs. The Government's inventory of leasable tracts would shrink in size and value. The amount of acreage leased under a leasing program that offered only the tracts that remain leasable at lower prices would be similar to that leased from larger offerings.

The basic concept of leasing OCS tracts from an inventory of investment opportunities which ripen, at least over the long run, can also provide a framework for analyzing the effects of the pace of leasing on the benefits realized by the economy. OCS investment opportunities ripen because increasing oil prices, decreasing geologic risk or increasing resource potential make the returns on leasing and exploration investments grow. These private returns are paralleled by the benefits to the economy as a whole. The economic benefits expected from a tract, measured in terms of net economic value as defined in Appendix F, increase as oil prices increase, risk decreases or resource potential increases. While the long term expectation of increasing oil prices implies a long term growth in the net economic value of OCS deposits, the timing of development also affects the overall benefit realized by the economy. As explained in Appendix F, this effect is measured by calculating the present values of benefits expected to be realized in various future times. Discounting future benefits to present value accounts for the fact that at an interest rate of, say, 8%, a dollar received 10 years from the present is worth $0.46 today while a dollar received 20 years from the present is worth $0.22 today.

This principle can be used to examine the consequences of different rates of leasing for the overall benefits which the economy realizes from development of OCS oil and gas deposits. For example, if leasing is restricted during a period of rapid growth in the value of OCS prospects, the inventory of unleased acreage will come to contain more tracts with higher net economic value. In particular, the amount of leasable resources (as defined in Appendix F) will increase and there would also be an increase in the number of



deposits that would experience a loss in total economic benefits if their development were delayed. In general, earlier leasing and development of such tracts will increase the benefit to the economy, measured in present value terms.

Even with unrestricted access to the inventory of unleased acreage, the investment process does not result in immediate leasing and exploration of all of the tracts that actually contain oil and gas. The process of searching through a sizeable inventory of unleased acreage to identify prospects that are worth leasing and exploring creates a sequence in the leasing of tracts, spreading the investments needed to locate economical oil and gas deposits over many years. The economic benefits realized from this search process can be increased if the search is conducted at a more rapid pace.

The temporary increase in the rate of searching for oil and gas that occurs when a substantial inventory of unexplored prospects becomes available causes greater economic benefit for two reasons. The first is the earlier discovery and development of the economical oil and gas on the tracts explored during the period of acceleration. The second is that exploration during the period of acceleration provides earlier information for locating prospects that occur toward the end of the search sequence. To illustrate this effect it is useful to picture a search in which 1,000 locations must be examined sequentially. If the search proceeds at the rate of 3 locations per month, it will take nearly 28 years to complete the search. Any prize in the last place to be searched is 28 years away. However, if the search rate is 10 locations per month for the first 5 years and then 3 per month until the search is complete, then the prize in the last location can be found after 16 years instead of 28 years. Although the sequence in the search for oil and gas is not fixed as in this example, temporary increases in the rate of leasing can be expected to have similar effects on the timing of the discovery of oil and gas prizes and the realization of their benefits to the economy. Such effects can be evaluated using present value calculations. Section III provides the results of such an analysis.

## III. Consequences of the Pace of Leasing for Investments and Economic Benefits

One of the key concerns expressed about the pace of OCS leasing is whether the larger and more rapid lease sales would bring about changes in the rate of investment in OCS exploration and development and the economic benefits from production of less costly oil and gas resources. Areawide leasing has been criticized as being unable to overcome capital limitations or change the timing of resource development.

Limitations on the capital available for OCS investments could result if firms active on the OCS could not or would not increase the budget allocated to lease acquisition and exploration and if other firms could not enter the offshore market even though it contained many good investment opportunities. Capital limitations would be evidenced by a limited increase in the rate of seismic data collection, lease acquisition and exploratory drilling despite the substantially expanded opportunities provided by accelerated leasing. Such capital limitations would be of concern in the formulation of the third 5-Year leasing program if there was evidence that they would not ease over time and that the number of attractive prospects that would be made available by the future leasing program would outpace the capital that could be made available. One response to such capital limitations would be to restrict the amount of acreage offered for lease by using procedures such as tract selection or focusing on promising acreage. Other possibilities include policies to promote the flow of capital into oil and gas exploration or to reduce the capital required to participate in leasing and exploration.

Areawide leasing was adopted in the 1982 5-Year Leasing Program in order to allow more rapid exploration, discovery and development of OCS oil and gas resources. This decision was based on the evidence that the government's inventory of unleased acreage contained numerous oil and gas prospects of sufficiently high value that they would be economical to develop and produce without waiting for higher oil and gas prices. As Appendix F describes, many such prospects had been economical for some years. Further delays in their development and production would have resulted in lower economic benefits to the nation's economy. There were also prospects, however, that were barely economical to explore or develop. If the 1982 inventory of unleased acreage had been comprised primarily of a moderate number of such low value prospects, then the rate of investment in exploration and development would not have been much affected by the choice of tract selection or areawide leasing. Both would have made available the limited number of prospects that were economic at each point in the 5-year period. If, on the other hand, the unleased inventory in 1983, when areawide sales began, contained a substantial number of good investment prospects, then the rate of investment could be increased substantially by areawide sales. Thus the amount of acreage leased and the bonuses paid can indicate the character of the inventory as areawide leasing began.

To determine whether the shift from tract selection to areawide procedures caused the desired expansion in leasing and investment in exploration, it is useful to examine data for leasing, seismic data collection, and exploratory drilling in an area in which there is substantial data under both procedures. Leasing in the Gulf of Mexico provides the best data for such an analysis. Since there has been insufficient time for lessees to complete the sequence of discoveries and development, it is not possible to determine empirically whether development investments have increased. It is possible, however, to assess the relationship between exploratory drilling investments and the expected timing of development investments. The cost of capital limits the number of years that firms will be willing to invest in exploratory drilling in advance of the time they expect to be able to develop profitably the oil and gas deposits they expect to find. Similarly, because the leases are limited to 5 years (in deep water, 10 years), firms will not acquire leases that they do not expect to be economical to explore within these time frames.

A. Lease Availability and Acquisition

Table 1 shows the acres offered, the acres leased and the cash bonuses collected in each year, separating the tract selection and areawide sales as of May 1983. In the Central and Western Gulf of Mexico, leasing proceeded under the tract selection procedures at a rate of about 1 million acres per year during the late 1970s and early 1980s. Almost twice as much acreage was offered, about 1.7 million acres per year. Despite the nomination and tract



Table 1

Rate of Lease Acquisition

(acreage in millions, bonuses in billions of dollars)

| | C & W Gulf of Mexico | | | Other Areas | | |
|---|---|---|---|---|---|---|
| Year | Acres Offered | Acres Leased | Total Bonuses | Acres Offered | Acres Leased | Total Bonuses |
| 1972 | 1.0 | .8 | 2.3 | | | |
| 1973 | 1.7 | .5 | 1.6 | .8 | .5 | 1.5 |
| 1974 | 5.0 | 1.8 | 5.1 | | | |
| 1975 | 6.0 | 1.3 | .8 | 1.3 | .3 | .4 |
| 1976 | 1.0 | .4 | .6 | 1.9 | .9 | 1.7 |
| 1977 | 1.1 | .6 | 1.2 | .8 | .5 | .4 |
| 1978 | 1.8 | 1.0 | 1.7 | 1.3 | .2 | .1 |
| 1979 | 1.2 | .8 | 3.2 | 2.3 | .9 | 1.9 |
| 1980 | 1.4 | 1.0 | 4.1 | 1.2 | .2 | .1 |
| 1981 | 2.2 | 1.3 | 3.9 | 5.5 | .9 | 2.6 |
| 1982 | 1.9 | .9 | 1.8 | 5.6 | 1.0 | 2.1 |
| 1983 | | | | | | |
| TS | .7 | .1 | - | 5.1 | .9 | .7 |
| AW | 70.5 | 5.3 | 4.9 | 43.8 | .3 | .1 |
| 1984 | 64.7 | 4.9 | 2.1 | 89.5 | 3.3 | 1.8 |
| 1985 | 51.2 | 3.2 | 1.4 | 35.8 | .2* | .1* |
| 1986 | 58.7 | 0.7 | 0.2 | | | |

*Subject to revision dependent upon the decision to issue leases for 39 tracts in Eastern Gulf of Mexico which are subject to Military Stipulation 5.

selection process, only half of the acreage selected as promising 20-some months prior to each sale proved worth bidding upon after further evaluation. In 1983, areawide leasing expanded the acreage offered in the Gulf of Mexico by a factor of 35. Acreage leased expanded from 1 million acres per year to about 5 million acres. This shows a very substantial increase in the amount of acreage evaluated, bid upon and transferred into the lease portfolios of offshore firms. It confirms the buildup of a sizeable inventory of good prospects and shows a substantial rate of lease acquisition in response to their availability. Beginning in 1984, the amount of acreage offered in the central and western Gulf of Mexico lease sales decreased, both because of previous leasing and the procedures to focus on promising acreage. The rate of lease acquisition also declined to 3.4 million acres in 1985, and 0.7 million in 1986.

In all other areas, lease offerings averaged about 3 million acres per year over the 1978-1982 period with leasing at about 0.7 million acres per year. Areawide leasing expanded the acreage offered in other areas to about 43.8 million acres in 1983, 89.5 million in 1984, abd 35.8 million in 1985 with leasing of a total of 3.8 million acres. As expected, the amount of valuable acreage built up in the Government's inventory was less in these mostly frontier areas.

The extent of the capital investment made by firms acquiring leases can be judged by examining the bonuses paid. Under tract selection procedures, bonuses for Gulf of Mexico leases averaged about $3 billion per year in the late 1970s and early 1980s, though they had dropped to half their 1980 peak by 1982. Under areawide procedures, total bonuses paid increased to nearly $5 billion and then fell off to $2.1 billion in 1984 and $1.5 million in 1985. With the sharp decline in oil prics in 1986, bonuses fell to $0.2 billion.

Total bonuses in the first round of areawide sales were nearly equal to the total net economic value of the resources estimated to be leased in Appendix 2 of the March 1982 SID for the 1982 5-Year Leasing Program. Because bonuses paid are estimated to be about 40 percent of net economic value in the Gulf of Mexico, this implies that industry leased about 2.5 times as much in 1983 as had been estimated. Thus the investment response was greater than expected at the time the 1982 program was approved.

Analysis by the MMS estimates that about 10 percent of the unleased undiscovered recoverable resource thought to be in the Gulf of Mexico areas in 1982 was leased in 1983 and another 7 percent was leased in 1984. This is about three times the portion that was estimated to be leased, which is fairly consistent with the estimate derived by comparing bonuses to net economic value. Evidently, the petroleum industry was willing to invest more in the acquisition of leases than had been anticipated.

B. Inventory Buildup and Depletion

The lease sales in the Gulf of Mexico provide a good basis for examining trends in the value of acreage being leased. Since leasing tends to focus on



the most valuable acreage, particularly if the acreage offered is limited, the average value can suggest the extent to which the inventory of unleased tracts has appreciated. In general, it is reasonable to conclude that the greater the value of the tracts leased, the greater has been the extent of appreciation that has occurred before the acreage was offered. Table 2 shows the trends in the average of high bids on tracts leased in each year starting in 1970.

The average of high bids is not a perfect indicator of the economic value of the tracts leased. If changes in competition allow firms to bid a smaller fraction of the value they see in a tract and still win the lease, then the average of high bids will decline relative to average economic value. The average of high bids is also subject to inflation effects which could mask changes in real economic value. Isolating the various factors that affect bid levels is a complex analytical task. Such a study is discussed in Section V.

The early history of leasing in the Gulf of Mexico shows the average of high bonus bids was generally less than $500 per acre, except for sales of drainage tracts for which nearby drilling had confirmed the presence of a commercial deposit. None of the wildcat lease sales of the 1950s and 1960s exceeded $1,000 per acre, despite the fact that exploratory drilling during that time yielded discoveries containing most of the oil and gas that has been discovered to date.

In the 1970s however, the average of high bids increased as OPEC began to exert its price setting power. The early 1970s saw the average of high bids in the $2,000 per acre range, increasing to nearly $5,000 per acre in 1974. Efforts to increase OCS leasing yielded relatively larger offerings in the Gulf of Mexico, reaching 5 million acres in 1974 and 6 million acres in 1975. As a result, a total of 3 million acres were leased in 1974 and 1975 combined. The average of high bids declined sharply to about $500 per acre in 1975.

The 1974-1975 decline in the average of high bids could have been caused by dilution of competition, by leasing more moderately valued tracts along with the higher valued tracts, or by depletion of the unleased inventory through leasing of the limited number of prospects that had been made highly valuable by the OPEC price increases. The trend in the average of high bids in the next 3 years, 1976-1978, gives evidence that the inventory had been substantially depleted of the highly valuable tracts that had emerged early in 1974. The average stayed substantially below the 1974 $5000 per acre peak during the 1976 through 1978 period when the acreage offered averaged about 1.3 million acres per year.

Thus, when lease offerings had returned to their pre-1973 size and, presumably, to their pre-1973 levels of competition, the better tracts being leased were similar in value to those being leased at the turn of the decade. The increased pace of leasing in 1974 and 1975 allowed acquisition of the valuable prospects that resulted from the appreciation effect of higher oil prices.

The trend in the average of high bids indicates a second period of inventory buildup during the 1978-1980 period. Gulf of Mexico lease sales during this

Table 2
Trends in Average of High Bonus Bids for Leased Tracts
(dollars per acre)

| | Gulf of Mexico | | California | | Atlantic | | Alaska | |
|---|---|---|---|---|---|---|---|---|
| Year | Sale | Average Bonus Per Acre | Sale | Average Bonus Per Acre | Sale | Average Bonus Per Acre | Sale | Average Bonus Per Acre |
| 1970 | 21 | 2,190 | | | | | | |
| | 22 | 1,530 | | | | | | |
| 1971 | 23 | 2,587 | | | | | | |
| 1972 | 24 | 2,018 | | | | | | |
| | 25 | 3,108 | | | | | | |
| 1973 | 26 | 2,908 | | | | | | |
| | 32 | 3,072 | | | | | | |
| 1974 | 33 | 4,968 | | | | | | |
| | 34 | 2,605 | | | | | | |
| | S1 | 302 | | | | | | |
| | 36 | 2,248 | | | | | | |
| 1975 | 37 | 438 | 35 | 1,346 | | | | |
| | 38 | 572 | | | | | | |
| | 38A | 485 | | | | | | |
| 1976 | 41 | 1,091 | | | 40 | 2,130 | 39 | 1,369 |
| | 44 | 2,129 | | | | | | |
| 1977 | 47 | 1,933 | | | | | CI | 805 |
| 1978 | 45 | 1,672 | | | 43 | 412 | | |
| | 65 | 304 | | | | | | |
| | 51 | 2,113 | | | | | | |
| 1979 | 58 | 3,189 | 48 | 1,987 | 49 | 180 | BF | 5,800 |
| | 58A | 4,539 | | | 42 | 2,277 | | |



Table 2 (Continued)
Trends in Average of High Bonus Bids for Leased Tracts
(dollars per acre)

| | Gulf of Mexico | | California | | Atlantic | | Alaska | |
|---|---|---|---|---|---|---|---|---|
| Year | Sale | Average Bonus Per Acre | Sale | Average Bonus Per Acre | Sale | Average Bonus Per Acre | Sale | Average Bonus Per Acre |
| 1980 | A62 | 4,853 | | | | | 55 | 551 |
| | 62 | 3,699 | | | | | | |
| 1981 | A66 | 3,312 | 53 | 6,388 | 46 | 1,218 | 60 | 60 |
| | 66 | 2,446 | | | 59 | 1,115 | | |
| 1982 | 67 | 2,022 | 68 | 669 | | | 71 | 3,101 |
| | 69(1) | 2,166 | | | | | | |
| 1983 | 69(2) | 646 | 73 | 366 | 76 | 325 | 57 | 946 |
| | 72 | 1,090 | | | 78 | 213 | 70 | 780 |
| | 74 | 668 | | | | | | |
| 1984 | 79 | 346 | 80 | 543 | | | 83 | 609 |
| | 81 | 581 | | | | | 87 | 722 |
| | 84 | 433 | | | | | | |
| 1985 | 98 | 520 | | | | | | |
| | 102 | 334 | | | | | | |
| | 94 | *229 | | | | | | |
| 1986 | 104 | 258 | | | | | | |
| | 105 | 247 | | | | | | |

*Subject to revision. See note at bottom of Table 1.

time offered an average of 1.5 million acres per year. The average of high bids peaked in 1980 at nearly $5,000 per acre just as oil prices and oil price expectations peaked. During 1981 and 1982, world oil prices and oil price expectations declined. Gulf of Mexico lease sales increased slightly to about 2 million acres per year offered and 1 million leased while the average of high bids declined gradually to about $2,000 per acre. Thus the 5 years before areawide leasing saw about 5 million acres leased while the average rose from about $2,000 per acre to nearly $5,000 per acre and then declined back to $2,000 per acre.

The average high bid for an OCS sale can be strongly influenced by a few very high value tracts, particularly in the smaller, tract selection sales. While the average would indicate the influence of the best tracts leased in each sale, the chance inclusion of very high value tracts in some sales and not in others that can be caused by emerging exploration results can make the average high bid a less useful measure of trends. (This is the case, for example, in Sale 53 which had an average bonus of $6,388 per acre.)

The median of high bids is less subject to the extremely high values of a few tracts. (The median is the middle value in a ranked list of values.) The medians of high bids for Gulf of Mexico sales since 1979 are shown in Table 3. The peak median high bid occurred in 1979. Significant decreases in the median high bid occurred from 1979 to 1982 as well as in 1983 through 1985.

Estimates made in late 1981 and early 1982 for the second 5-year leasing program indicated unleased oil and gas resources in the Central and Western Gulf of Mexico of 15.6 billion BOE and a net economic value of about $200 billion. These estimates, together with the relatively high average bids during the previous 4 years, suggested that the Government had built up a substantial inventory of tracts worthy of investment.

The extent of leasing in 1983 through 1985, despite significant further decreases in world oil prices and price expectations, confirms the existence of a substantial unleased inventory in 1982. The areawide lease sales in the Central and Western Gulf leased over 13 million acres in these 3 years. This is more than the total amount of Gulf of Mexico acreage leased over the previous 15 years. Since lease values would not have appreciated, except because of new geological knowledge, during the price declines between 1981 and 1985, it is clear that most of the acreage leased in 1983 was already ripe for investment at least as early as 1981 when prices were higher.

The evidence of buildup in the unleased inventory in other OCS areas is not as dramatic as it was in the Gulf of Mexico. The increase in acreage leased is not great though it is significant in value. Early frontier area sales in the Atlantic and Alaska areas yielded average high bids substantially higher than sales at a comparable point in the history of exploration in the Gulf of Mexico. Lease sales 40 and 42 in the Mid- and North Atlantic areas yielded average high bids of more than $2,000 per acre. The first sales in the Beaufort Sea had averages of $5,000 and $3,100 per acre. Values so much higher than the $500 per acre level of early Gulf of Mexico leases are strong evidence that the best prospects in the Government's inventory of tracts in these frontier areas had appreciated substantially in value before they were offered.



Table 3

Trends in the Median of High Bonus Bids for Leased Tracts

(dollars per acre)

Central and Western Gulf of Mexico Sales

| YEAR | Sale | Bid Per Acre |
|---|---|---|
| 1979 | 58 | 1,561 |
| | 58A | 2,529 |
| 1980 | A62 | 1,982 |
| | 62 | 2,231 |
| 1981 | A66 | 1,726 |
| | 66 | 958 |
| 1982 | 67 | 844 |
| | 69(1) | 775 |
| 1983 | 72 | 473 |
| | 74 | 390 |
| 1984 | 81 | 282 |
| | 84 | 267 |
| 1985 | 98 | 241 |
| | 102 | 212 |
| 1986 | 104 | 206 |
| | 105 | 196 |

Interpretation of trends in bids is complicated by the fact that an average is sensitive to the mixture of tracts sold. Relatively small offerings composed of tracts of sufficiently good prospects to have been nominated by a number of firms, would yield higher averages than much larger sales from the same inventory of tracts even if the bids were not affected by the size of the offering. A larger sale with more low value tracts added into the total along with the fewer high value tracts that would have been leased in a smaller sale would have a lower average bonus. The average of high bids would only provide strong evidence of an inventory buildup for sales of comparable size and selection. With the exception of the larger Gulf of Mexico sales in 1974 and 1975, the lease sales of the 1970s were comparable in this respect.

C. Exploration Investments in the Gulf of Mexico

Since areawide leasing was initiated, seven such lease sales held through 1985 have been held in the Gulf of Mexico. Approximately 2 years have passed since OCS Lease Sale 72, the first areawide Central Gulf of Mexico lease sale was held on May 25, 1983. Subsequent areawide and focused lease sales were held in the Western Gulf of Mexico on August 24, 1983, July 18, 1984, and August 14, 1985, and in the Eastern Gulf of Mexico on January 5, 1984, and in the Central Gulf on April 24, 1984, and May 22, 1985.

The exploration process begins with the collection of geological and geophysical data using primarily seismic techniques. These data are used to identify unleased tracts with good prospects for the discovery of oil and gas. Seismic data collection in the Gulf of Mexico had been occurring typically at the rate of about 150,000 miles of seismic data per year during the 1978-1981 period. In 1982, in anticipation of the areawide lease sales in 1983, it rose to nearly 380,000 miles. In 1983, it was over 295,000 miles. These substantial investments in data collection were made in an area that was already among the most intensively studied in the world. It tends to show that the oil industry believed in 1982 and 1983, that there was an extensive inventory of acreage worth considering.

Drilling and discovery data are now available for leases issued in the Central and Western Gulf, Lease Sales 72, 81, 98 and 74, 84, 102 respectively, as a result of the areawide sales. These data provide a comparison of the exploration activity on leases issued for areawide and tract selection sales in the Central and Western Gulf.

One difficulty in making comparisons between tract selection and areawide sales is in the variation in the time available for drilling activities. The data presented in the analysis and tables below are current as of November 1, 1985. It is obvious that leases issued from Lease Sale 58, held July 3, 1979, have been in force for a period of more than 5 years and it may be expected that more activity would occur on those leases than on those issued in 1983.

In order to provide some basis of comparison for leases with different time spans between lease issuance and the cutoff date of October 10, 1986, the following procedure was adopted. All data on tracts showing progress in drilling and discovery were compiled for a specific lease sale and a percentage of the total number of tracts in the sale showing progress was computed. Each of these percentages was divided by the period of time between the lease sale and the cutoff date, yielding an average annual percentage.



Comparison of the average annual percentages provide an approximate indication of the differences that may exist between tract selection sales and areawide sales, after removing some of the differences that are due to the longer period of exploration and development time available to the tract selection sales.

Three comparison tables were prepared. First, a comparison of the tracts on which drilling has taken place as a percentage of tracts leased for Gulf of Mexico sales from 1979 through 1985. Second, a comparison of new productive leases as a percentage of tracts drilled for the same areas and same time period. Third, a comparison of tracts classified as new field discoveries as a percentage of tracts drilled for the same areas and same time period.

Table 4 contains a summary of exploratory drilling activity by both individual sales and on an annual basis. All of the sales between 1979 and 1982 were tract selection sales and the 1983 sales were areawide. The annual average percentages indicate that, in the Gulf of Mexico, lessees tend to drill each year 11 to 8 percent of the leases acquired in a given lease sale until approximately 85 percent of the leases have been drilled. The remainder of the acquired leases remain undrilled. The average annual percentage for areawide Sales 72 and 74 are in accord with the similar averages pertaining to the tract selection sales. The Sale 81 and 84 average is somewhat less while the Sale 98 and 102 average is less than six percent; however, since relatively little drilling can occur in the first few months of a lease, this average reflects the short period in which Sale 98 and 102 leases have been active as of the time of this data. In addition sale 81, 84, 98 and 102 leases were issued about 2.5 months after the sale while the other leases were issued within a couple of weeks of a sale. The Sale 69 tracts show a somewhat greater than average rate of exploration. This may be due to the above average potential of those tracts. It may also be the result of drilling efforts in preparation for the areawide sales planned for 1983 and 1984.

The rate of progress in drilling on leases issued in areawide sales thus appears to be nearly the same as the long run rate of drilling on leases from tract selection sales despite the fact that almost 10 times as many tracts were leased. The increased acquisition of leases in Sales 72 and 74 has been followed by an increased investment in exploratory drilling. The increase in the pace of investment is particularly apparent in the yearly data with about three times as many 1983 tracts drilled as have been drilled, on average, on tracts leased in 1979-1982 sales, despite the shorter time since the 1983 lease sales.

Table 5 contains a summary of new productive leases as a percentage of leases drilled. The percentage of tracts drilled that are productive is lower for areawide sales than for tract selection sales. One reason is that even when oil or gas is found on a tract it is not necessarily the first well that is productive. Later wells on a tract may prove productive and the percentage will increase. In fact, the percentage did increase in the second year of exploration on leases from sales 72 and 74. Another reason is that there were more marginal tracts leased in the areawide sales and the percentage is expected to be lower.

Table 6 contains a summary of new field discoveries as a percentage of leases drilled. The areawide sales in 1983 have a higher rate of new field

Table 4
Gulf of Mexico Exploratory Drilling Activity

A. By Sale

| Sale | Date | Tracts Leased | Tracts Drilled | Percent of Leased Tracts Drilled | Years Active[1] | Average Annual Percentage (Col.5/Col.6) |
|---|---|---|---|---|---|---|
| 58 | 07/31/79 | 81 | 76 | 93.8 | 7.2 | 13.0 |
| 58A | 11/27/79 | 90 | 75 | 83.3 | 6.8 | 12.2 |
| A62 | 09/30/80 | 116 | 98 | 84.5 | 6.0 | 14.1 |
| 62 | 11/18/80 | 67 | 51 | 76.1 | 5.8 | 13.1 |
| A66 | 07/21/81 | 156 | 100 | 64.1 | 5.2 | 12.3 |
| 66 | 10/20/81 | 102 | 55 | 53.9 | 4.9 | 11.0 |
| 67 | 02/09/82 | 115 | 59 | 51.3 | 4.6 | 11.2 |
| 69 | 11/17/82 | 56 | 39 | 69.6 | 3.8 | 18.3 |
| 69A[2] | 03/08/83 | 11 | 7 | 63.6 | 3.5 | 18.2 |
| 72 | 05/25/83 | 623 | 274 | 44.0 | 3.3 | 13.3 |
| 74 | 08/24/83 | 406 | 154 | 37.9 | 3.1 | 12.2 |
| 79 | 01/05/84 | 156 | 6 | 3.8 | 2.7 | 1.4[5] |
| 81 | 04/24/84 | 453 | 95 | 21.0 | 2.4 | 8.7 |
| 84 | 07/18/84 | 361 | 59 | 16.3 | 2.2 | 7.4 |
| 98 | 05/22/85 | 409 | 29 | 7.1 | 1.3 | 5.5 |
| 102 | 08/14/85 | 195 | 6 | 3.1 | 1.1 | 2.8 |
| 94 | 12/18/85 | 38[6] | 0 | 0 | .8 | - |
| 104 | 04/30/86 | 101 | 1 | 1.0 | .4 | 2.5 |
| 105 | 08/27/86 | 41 | 0 | 0 | .1 | - |

B. By Year

| Year | Sales | Tracts Leased | Tracts Drilled | Percent of Leased Tracts Drilled | Average Years Active[4] | Average Annual Percentage (Col.5/Col.6) |
|---|---|---|---|---|---|---|
| 1979 | (58,58A) | 171 | 151 | 88.3 | 7.0 | 12.6 |
| 1980 | (A62,62) | 183 | 149 | 81.4 | 5.9 | 13.8 |
| 1981 | (A66,66) | 258 | 155 | 60.1 | 5.1 | 11.8 |
| 1982[2] | (67,69,69A) | 182 | 105 | 57.7 | 4.2 | 13.7 |
| 1983[3] | (72,74,79) | 1185 | 434 | 36.6 | 3.2 | 11.4 |
| 1984 | (81,84) | 814 | 154 | 18.9 | 2.3 | 8.2 |
| 1985 | (98,102,94) | 642 | 35 | 5.5 | 1.3 | 4.2 |
| 1986 | (104,105) | 142 | 1 | 0.7 | 0.4 | 1.7 |

[1]Number of years that leases from sale have been in effect as of 10/10/86 when drilling data was compiled.
[2]Sale 69A, a tract selection sale, was held early in 1983 but is included with the major portion of Sale 69.
[3]Sale 79, an areawide sale, was planned for 1983, but was delayed until early 1984. It is included herein with the other 1983 sales.
[4]Average among sales weighted by number of tracts drilled.
[5]Drilling rates have been artificially depressed by constraints on the pace of permit approvals due to Defense Department requirements.
[6]39 aditional tracts covered by Military Stipulation 5 were bid upon but leases have not been issued as of 10/10/86.



Table 5

Gulf of Mexico New Productive Leases

A. By Sale

| Sale | Tracts Drilled | Productive Tracts | Percent of Drilled Tracts That Are Productive | Years Active[1] | Average Annual Percentage (Col.4/Col.5) |
|---|---|---|---|---|---|
| 58 | 76 | 47 | 61.8 | 7.2 | 8.6 |
| 58A | 75 | 44 | 58.7 | 6.8 | 8.6 |
| A62 | 98 | 57 | 58.2 | 6.0 | 9.7 |
| 62 | 51 | 28 | 54.9 | 5.8 | 9.5 |
| A66 | 100 | 54 | 54.0 | 5.2 | 10.4 |
| 66 | 55 | 30 | 54.5 | 4.9 | 11.1 |
| 67 | 59 | 35 | 59.3 | 4.6 | 12.9 |
| 69 | 39 | 17 | 43.6 | 3.8 | 11.5 |
| 69A | 7 | 3 | 42.9 | 3.5 | 12.3 |
| 72 | 274 | 124 | 45.3 | 3.3 | 13.7 |
| 74 | 154 | 56 | 36.4 | 3.1 | 11.7 |
| 79 | 6 | 0 | 0 | 2.7 | 0 |
| 81 | 95 | 42 | 44.2 | 2.4 | 18.4 |
| 84 | 59 | 9 | 15.3 | 2.2 | 7.0 |
| 98 | 29 | 11 | 37.9 | 1.3 | 29.2 |
| 102 | 6 | 1 | 16.7 | 1.1 | 15.2 |
| 94 | 0 | 0 | - | 0.8 | - |
| 104 | 1 | 0 | 0 | 0.4 | 0 |
| 105 | 0 | - | - | 0.1 | - |

B. By Year

| Year | Sales | Tracts Drilled | Productive Tracts | Percent of Drilled Tracts That Are Productive | Average Years Active[2] | Average Annual Percentage (Col.5/Col.6) |
|---|---|---|---|---|---|---|
| 1979 | (58,58A) | 151 | 91 | 60.3 | 7.0 | 8.6 |
| 1980 | (A62,62) | 149 | 85 | 57.0 | 5.9 | 9.7 |
| 1981 | (A66,66) | 155 | 84 | 54.2 | 5.1 | 10.6 |
| 1982 | (67,69,69A) | 105 | 55 | 52.4 | 4.2 | 12.5 |
| 1983 | (72,74,79) | 434 | 180 | 41.5 | 3.2 | 13.0 |
| 1984 | (81,84) | 154 | 51 | 33.1 | 2.3 | 14.4 |
| 1985 | (98,102,94) | 35 | 12 | 34.3 | 1.3 | 26.4 |
| 1986 | (104,105) | 1 | 0 | 0.0 | 0.4 | 0.0 |

[1]Number of years that leases from sale have been in effect as of 10/10/86.
[2]Average among sales weighted by number of tracts drilled.

Table 6

Gulf of Mexico New Field Discoveries

A. By Sale

| Sale | Date | Tracts Drilled | New Field Discoveries | Percentage of Drilled Tracts with Discoveries | Years Active[1] | Average Annual Percentage (Col.5/Col.6) |
|---|---|---|---|---|---|---|
| 58 | 07/03/79 | 76 | 12 | 15.8 | 7.2 | 2.2 |
| 58A | 11/27/79 | 75 | 11 | 14.7 | 6.8 | 2.2 |
| A62 | 09/30/80 | 98 | 15 | 15.3 | 6.0 | 2.6 |
| 62 | 11/18/80 | 51 | 15 | 29.4 | 5.8 | 5.1 |
| A66 | 07/21/81 | 100 | 26 | 26.0 | 5.2 | 5.0 |
| 66 | 10/20/81 | 55 | 17 | 30.9 | 4.9 | 6.3 |
| 67 | 02/09/82 | 59 | 24 | 40.7 | 4.6 | 8.8 |
| 69 | 11/17/82 | 39 | 6 | 15.4 | 3.8 | 4.1 |
| 69A | 03/08/83 | 7 | 2 | 28.6 | 3.5 | 8.2 |
| 72 | 05/25/83 | 274 | 72 | 26.3 | 3.3 | 8.0 |
| 74 | 08/24/83 | 154 | 31 | 20.1 | 3.1 | 6.5 |
| 79 | 01/05/84 | 6 | 0 | 0 | 2.7 | 0 |
| 81 | 04/24/84 | 95 | 22 | 23.2 | 2.4 | 9.7 |
| 84 | 07/18/84 | 59 | 8 | 13.6 | 2.2 | 6.2 |
| 98 | 05/22/85 | 29 | 4 | 13.8 | 1.3 | 10.6 |
| 102 | 08/14/85 | 6 | 0 | 0 | 1.1 | 0 |
| 94 | 12/18/85 | 0 | 0 | - | 0.8 | - |
| 104 | 04/30/86 | 1 | 0 | 0 | 0.4 | 0 |
| 105 | 08/27/86 | 0 | 0 | - | 0.1 | - |

B. By Year

| Year | Sales | Tracts Drilled | New Field Disc. | Percentage of Drilled Tracts with Discoveries | Average Years Active[2] | Average Annual Percentage |
|---|---|---|---|---|---|---|
| 1979 | (58,58A) | 151 | 23 | 15.2 | 7.0 | 2.2 |
| 1980 | (A62,62) | 149 | 30 | 20.1 | 5.9 | 3.4 |
| 1981 | (A66,66) | 155 | 43 | 27.7 | 5.1 | 5.4 |
| 1982 | (67,69,69A) | 105 | 32 | 30.5 | 4.2 | 7.3 |
| 1983 | (72,74,79) | 434 | 103 | 23.7 | 3.2 | 7.4 |
| 1984 | (81,84) | 154 | 30 | 19.5 | 2.3 | 8.5 |
| 1985 | (98,102,94) | 35 | 4 | 11.4 | 1.3 | 8.8 |
| 1986 | (104,105) | 1 | 0 | 0 | 0.4 | 0 |

[1]Number of years that leases from sale have been in effect as of 10/10/86.
[2]Average among sales weighted by number of tracts drilled.



discoveries than some of the previous tract selection sales. In fact, the new field discoveries from the 1983 sales exceeds the new field discoveries from sales in 1980-1982.

The data shown on these tables cover a period of relatively abrupt changes in the market prices for oil and gas, as well as expectations regarding future prices, which may be reflected in drilling and production activities. Crude oil prices and expectations increased from 1979 through 1981 and subsequently declined, and natural gas prices came under downward pressure early in 1983. These trends would tend to dampen drilling investments in 1982 and 1983. Thus, the increased rate of drilling on the tracts leased in 1983 areawide sales is despite, rather than because of, the trends in oil prices.

The average annual percentages on Tables 4, 5 and 6 are somewhat affected by the differences in the ages of the leases from each sale. In the tract selection sales, 25-35 percent of the tracts were drilled in the first year after issuance of a lease. By the second year after issuance, 35-65 percent of the tracts in the tract selection sales had been drilled. In sale 72, 31 percent of the tracts were drilled 23 months after the sale. In sale 74, 27 percent of the tracts were drilled 19 months after the sale. The average annual percentages therefore somewhat overstate the drilling from areawide sales relative to tract selection sales. Comparisons of these tables with similar tables prepared with data through November 1, 1984, however lead to the conclusion that these variations are not significant.

This comparison of postlease exploration activity suggests that areawide leasing has had a favorable effect on investment. Although leases resulting from areawide lease Sales 72 and 74 have been in existence only about three years, drilling activity, based on number of leases drilled, seems to have proceeding at a high rate for two years, then dropped off as oil prices declned in 1986. At the time of the analysis (October 1986), Sale 72 had been held less than 3.5 years earlier, and more Sale 72 leases had been drilled than leases from any other sale studied. Similarly, more Sale 74 leases had been drilled in their first year than in the any period of any tract selection lease sale studied.

The level of investment in exploratory drilling can also be measured by the number of drilling rigs active. In the Gulf of Mexico, there were almost 200 rigs active in late 1984 and in late 1985 about 150 rigs were active. This was an increase from a low of about 120 during the summer of 1983 as the first areawide sales were occurring. This was a record level of drilling activity in the Gulf of Mexico and was counter to the trend of world oil prices in 1983 and through 1985. In 1986, the sharp drop in oil prices reduced the oil industry earnings available to pay for exploratory drilling and the number of active rigs fell.

Lessees' intentions to invest in exploratory drilling can be gauged by the exploration plans they have filed to gain the necessary permits from the MMS. During the period of 1978-1982, Gulf of Mexico exploration plans were filed at an average rate of about 450 per year. Filings in 1983 were over 500 and in 1984 they reached 800. This demonstrates the likelihood that investments in exploratory drilling would have continued in 1985 and 1986 at a rate similar to or greater than the rate in 1984 had oil prices not dropped so sharply.

D. Effects on Economic Benefits

The investments evident in lease acquisition and exploratory drilling indicate the lessees' expectations about potential returns. The framework developed in Section II can also be used to analyze the effects of different leasing rates on the total economic benefits realized by the economy. Figures 1 and 2 show the results of an analysis which compares the economic benefits from leasing in the Central and Western Gulf of Mexico under rapid leasing typical of the areawide and focused-on-promising-acreage approaches on one hand and slower leasing of 200 tracts per year typical of the 1976-1982 era tract selection lease sales on the other. Actual leasing results were used for 1982-1986. Projections of leasing under the Base Schedule Option (SID, Part III.A.2.) for 1987-1992 were used. Leasing of the currently leasable resources remaining to be leased in 1992 was assumed to occur at the rate of 200 tracts per year containing a total of 400 million barrels (risked).

This comparison is not intended to be a forecast of leasing under tract selection procedures. Nor is it meant to be a forecast of leasing beyond the 1987-1992 program. It's purpose is to illustrate the substantial effects on the economy that can result from more rapid leasing of those prospects ripe for investment, as are the leasable resources in the Central and Western Gulf of Mexico.

Figure 1 shows estimates of the cumulative economic benefits achieved by leasing in the Central and Western Gulf of Mexico starting in 1982, leasing the same resources at different rates. The economy benefits by about $41 billion more under the more rapid leasing program. The economy is ahead under more rapid leasing in every year.

Figure 2 shows the results of this analysis in a form that allows comparison of the economic benefits realized from the sets of tracts leased under the different programs. For the 3,129 tracts leased under the 1982-1986 period, the two bars show the total economic benefits under the leasing program actually implemented compared to the leasing of tracts having the same economic value at 200 tracts per year over the 1982-1997 period. The more rapid program is expected to achieve $23 billion more in economic benefits from development of the resources leased than would be expected from the 200 tract per year program.

Similarly, for the 2,008 tracts assumed to be leased in the 1987-1992 program, the two bars in Figure 2 show the total economic benefits from leasing in those five years as compared with the benefits that would result if the same tracts were leased in the 1997-2007 period under a 200 tract per year program. Note that because of the slower leasing rate since 1983, the leasing of the remaining tracts begins 10 years later under the 200 tract per year program. The more rapid program yields $11 billion more in economic benefits.

The bars in Figure 2 for the currently leasable resources that remain to be leased in 1992 after the end of the 1987-1992 program show the economic benefits from leasing 2,641 tracts at 200 tracts per year from 1992 through 2005 under the more rapid areawide type program compared to the benefits from leasing at 200 tracts per year from 2007 through 2020 under the slower program. Slower leasing of the 5,137 tracts leased starting in 1982 delays the leasing and the realization of the benefits from the remaining tracts by



Figure 1
CUMULATIVE ECONOMIC BENEFITS OF
RAPID AND SLOWER LEASING PROGRAMS
CENTRAL AND WESTERN GULF OF MEXICO
(Base Case)

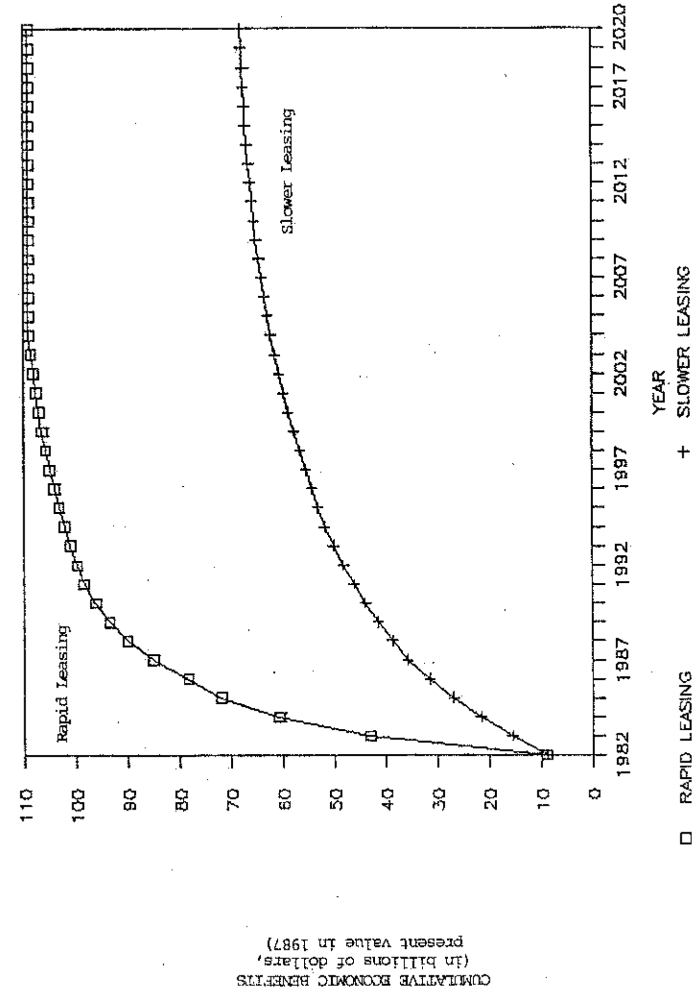
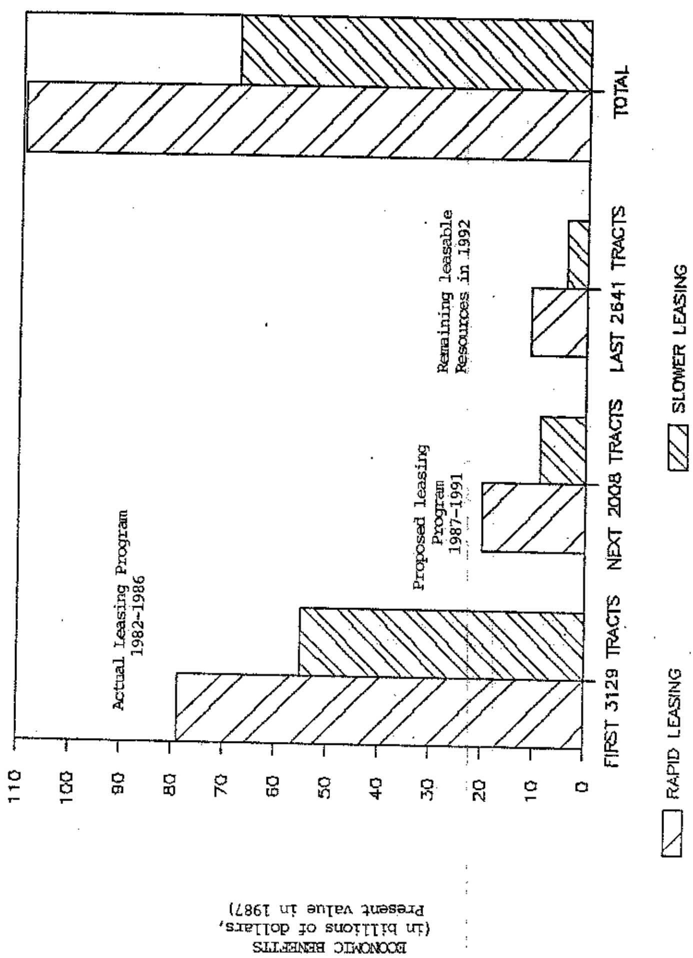


Figure 2
ECONOMIC BENEFITS OF
RAPID AND SLOWER LEASING PROGRAMS
CENTRAL AND WESTERN GULF OF MEXICO






13 years. The economy gains about $7 billion from the faster program. It is important to note that this $7 billion difference results, not from more rapid leasing of the 2,641 remaining tracts, but from the fact that they can be leased and developed sooner because of the information generated by earlier leasing and exploration of the preceding tracts.

Table 7 shows the leasing schedules and associated present values of the two options for the cases illustrated in Figures 1 and 2. The assumptions for this case are a $24 per barrel price of oil in 1987, a one percent per year price growth thereafter, and a real discount rate of eight percent.

For the rapid leasing scenario, the analysis used the actual program results from 1982-1986. For these years, the net economic values of the resources were estimated by dividing the total of bonuses on leased tracts by a ratio of bonus bids to total government receipts of 0.37. Some comments have suggested that the areawide program reduced competition in the lease auctions, resulting in lower bonuses on each tract than would have been received under a slower leasing program. A recent GAO study,[1] for example, estimated that bonuses would have been $3.1 million more per tract under tract selection. Although there is substantial debate over the correctness of the methods GAO used to calculate this number (see Section V of this appendix), $3.1 million per tract were added to the bonus revenue in 1983-1985 before dividing by 0.37 to adjust for this concern. The benefit estimates were inflated to the 1987 base year using the implicit GNP deflator and assuming 3% inflation in 1986.

For 1986, the amount of resource leased was estimated by subtracting the risked leasable resources in the proposed program (Appendix F, Table 8) from the expected resources in the 1982 program document. It was assumed that, on average, each tract leased in the current program has the same quantity of resources. The number of tracts leased in 1986 was assumed to be 500 for the $24 scenario which is consistent with the 1982-1985 trend and the estimates for the 1987-1992 base schedule. The net economic value per barrel was also taken from the 1982 program assumptions, but was adjusted for the price decline that has occurred in the ensuing years.

For subsequent years, the pace of leasing was specified using estimates of remaining leasable resources. In each year, the leased tracts were assumed to contain an average of 2.0 million barrels of oil equivalent per tract. Table 1 in Appendix R shows the developable resources expected to be leased from 1987-1992, except for those expected to be leased in Sale 110. Adjusting these to leasable resources and dividing by the average volume of resources per tract gives an estimate of the number of tracts leased in each year. After 1992, it was assumed that 200 tracts per year would be leased until all of the currently leasable resource has been leased. The net economic value was determined from the estimated net economic value per barrel of oil equivalent (boe) (Appendix F, Table 6A) with the assumed price growth and a constant cost of $4.00/boe, which reflects the maturity of production technology in the Gulf of Mexico.

It is likely that the better tracts will tend to be leased earlier, and that the tracts being leased would decline in value as leasing proceeds. This

[1]GAO, Early Assessment of Interior's Area-Wide Program For Leasing Offshore Lands, July 15, 1985.

TABLE 7

ECONOMIC BENEFITS OF RAPID AND SLOWER LEASING PROGRAMS

CENTRAL AND WESTERN GULF OF MEXICO

| YEAR | NUMBER OF TRACTS LEASED: RAPID LEASING | NUMBER OF TRACTS LEASED: SLOWER LEASING | PRESENT VALUE OF ECONOMIC BENEFITS IN YEAR LEASED: RAPID LEASING ($ Millions) | PRESENT VALUE OF ECONOMIC BENEFITS IN YEAR LEASED: SLOWER LEASING ($ Millions) | PRESENT VALUE OF ECONOMIC BENEFITS IN 1987: RAPID LEASING ($ Millions) | PRESENT VALUE OF ECONOMIC BENEFITS IN 1987: SLOWER LEASING ($ Millions) |
|---|---|---|---|---|---|---|
| 1982 | 182 | 182 | 4,974 | 4,974 | 8,942 | 8,942 |
| 1983 | 1,029 | 200 | 21,782 | 4,234 | 34,082 | 6,624 |
| 1984 | 814 | 200 | 12,679 | 4,234 | 17,697 | 5,989 |
| 1985 | 604 | 200 | 8,992 | 4,234 | 11,158 | 5,254 |
| 1986 | 500 | 200 | 5,751 | 4,234 | 6,395 | 4,708 |
| SUBTOTAL: Tracts Leased in 1982-1986 | 3,129 | 982 | 54,177 | 21,908 | 78,274 | 31,437 |
| 1987 | 555 | 200 | 6,689 | 4,234 | 6,689 | 4,234 |
| 1988 | 476 | 200 | 5,457 | 3,277 | 5,053 | 3,035 |
| 1989 | 363 | 200 | 3,981 | 3,115 | 3,413 | 2,671 |
| 1990 | 330 | 200 | 3,502 | 3,115 | 2,780 | 2,473 |
| 1991 | 284 | 200 | 2,924 | 3,115 | 2,149 | 2,290 |
| SUBTOTAL: Tracts Leased in 1987-1991 | 2,008 | 1,000 | 22,553 | 16,857 | 20,084 | 14,702 |
| 1992 | 200 | 200 | 2,006 | 3,007 | 1,365 | 2,047 |
| 1993 | 200 | 200 | 1,977 | 2,977 | 1,246 | 1,876 |
| 1994 | 200 | 200 | 1,947 | 2,977 | 1,136 | 1,737 |
| 1995 | 200 | 200 | 1,914 | 2,459 | 1,034 | 1,329 |
| 1996 | 200 | 200 | 1,880 | 2,380 | 940 | 1,151 |
| 1997 | 200 | 147 | 1,844 | 1,691 | 854 | 783 |
| SUBTOTAL: First 3129 Tracts Leased in Slower Program | | 3,129 | | 54,177 | | 55,061 |



TABLE 7 (cont.)

| YEAR | NUMBER OF TRACTS LEASED: RAPID LEASING | NUMBER OF TRACTS LEASED: SLOWER LEASING | PRESENT VALUE OF ECONOMIC BENEFITS IN YEAR LEASED: RAPID LEASING ($ Millions) | PRESENT VALUE OF ECONOMIC BENEFITS IN YEAR LEASED: SLOWER LEASING ($ Millions) | PRESENT VALUE OF ECONOMIC BENEFITS IN 1987: RAPID LEASING ($ Millions) | PRESENT VALUE OF ECONOMIC BENEFITS IN 1987: SLOWER LEASING ($ Millions) |
|---|---|---|---|---|---|---|
| 1997 | | 53 | | 754 | | 349 |
| 1998 | 200 | 200 | 1,806 | 2,875 | 774 | 1,233 |
| 1999 | 200 | 200 | 1,766 | 2,852 | 701 | 1,133 |
| 2000 | 200 | 200 | 1,724 | 2,828 | 634 | 1,040 |
| 2001 | 200 | 200 | 1,680 | 2,801 | 572 | 954 |
| 2002 | 200 | 200 | 1,635 | 2,773 | 515 | 874 |
| 2003 | 200 | 200 | 1,587 | 2,744 | 463 | 801 |
| 2004 | 200 | 200 | 1,538 | 2,712 | 416 | 733 |
| 2005 | 41 | 200 | 305 | 2,679 | 76 | 670 |
| 2006 | | 200 | | 2,643 | | 612 |
| 2007 | | 155 | | 2,019 | | 433 |
| SUBTOTAL: Next 2008 Tracts Leased In Slower Program | | 2,008 | | 27,680 | | 8,832 |
| 2007 | | 45 | | 573 | | 123 |
| 2008 | | 200 | | 2,566 | | 510 |
| 2009 | | 200 | | 2,525 | | 464 |
| 2010 | | 200 | | 2,482 | | 423 |
| 2011 | | 200 | | 2,436 | | 384 |
| 2012 | | 200 | | 2,389 | | 349 |
| 2013 | | 200 | | 2,339 | | 316 |
| 2014 | | 200 | | 2,287 | | 286 |
| 2015 | | 200 | | 2,233 | | 259 |
| 2016 | | 200 | | 2,177 | | 234 |
| 2017 | | 200 | | 2,118 | | 210 |
| 2018 | | 200 | | 2,057 | | 189 |
| 2019 | | 200 | | 1,994 | | 170 |
| 2020 | | 196 | | 1,890 | | 149 |
| SUBTOTAL: Last 2641 Tracts Leased | 2,641 | 2,641 | 23,608 | 30,066 | 10,728 | 4,067 |
| TOTALS: | 7,778 | 7,778 | | 1987 PRESENT VALUE: | 109,086 | 67,960 |
| | | | | DIFFERENCE: | 41,126 | |

decline was modeled by constructing a linear decline in value of the tracts leased over the history of leasing starting in 1982. The net economic value per tract was assumed to decline linearly from 1.5 times the average tract value to just over half of the average value when leasing is completed.

In the slower leasing scenario, 200 tracts per year were assumed to be leased throughout the program. An underlying assumption of the comparison of different leasing rates is that the same tracts are leased in the same order under each scenario. Thus, the net economic value per tract of the first 1,000 tracts leased in 1983 under the rapid leasing program must be applied to the years 1983-1987 in the slower program. This method of assigning net economic value to the 200 tract per year schedule was applied until all of the resource leased under the current program had been "leased" in the slower approach.

The actual economic values realized from the slower leasing of these tracts may differ from estimates based on the assumption that their value would not be affected by the timing of leasing. On the one hand, their values may be underestimated because gains from price growth after 1987 were not included. On the other hand, the values estimated for the slower program may be overstated because they do not reflect the declines in price and price expectations that occurred between the intial areawide leasing and the time the same tracts would be leased under a 200 tract per year program. It is not possible at this time to say which effect will be the stronger. Starting in 1997, the linear decline formula is used to estimate the net economic value.

The resulting estimates show that more rapid leasing typical of the areawide approach would provide an extra $41 billion of economic benefits over slower leasing typical of tract selection, in 1987 present value. About $23 billion of this difference is realized by earlier leasing and development of the tracts leased during the current program. The remaining difference arises from two sources: the earlier realization of the benefits from tracts leased under the more rapid program in the years 1987-1991 and earlier leasing of those tracts with leasable resources which remain to be leased in 1992. This earlier leasing occurs because of accelerated leasing in the preceding years.

Six other cases were analyzed to see how this difference would vary under alternate assumptions. These results are presented in Table 8. The first variation assumes that the actual bonus bids under the rapid leasing scenario accurately reflect the economic benefits associated with the leased tracts. The actual bid data were used to determine the net economic value of the tracts leased in 1983-1985, without the additional $3.1 million per tract assumed in the initial case. This reduces the value of the first 3,129 tracts leased and, therefore, the benefits of more rapid leasing. In this case, the difference in present value between the faster and slower scenarios is over $31 billion.

The next set of variations alter the basic economic assumptions, using a two percent price growth, a six percent real discount rate, and a combination of the two. In these cases, the net economic value per barrel was varied in accordance with Table 13 in Appendix F. Both the higher rate of price increase and a lower rate of discount increase the value of leasing in later years. Offsetting this effect is the boost in economic benefits from the more rapid leasing of oil having greater economic value in the 1987-1992 period.



TABLE 8

COMPARISON OF ECONOMIC BENEFITS UNDER DIFFERENT LEASING AND ECONOMIC ASSUMPTIONS

CENTRAL AND WESTERN GULF OF MEXICO

PRESENT VALUE OF ECONOMIC BENEFITS IN 1987 ($ Millions)

| DESCRIPTION OF CASE | FIRST 3129 TRACTS | | NEXT 2008 TRACTS | | REMAINING 2641 TRACTS | | TOTAL | | DIFFERENCE |
|---|---|---|---|---|---|---|---|---|---|
| | RAPID LEASING | SLOWER LEASING | RAPID LEASING | SLOWER LEASING | RAPID LEASING | SLOWER LEASING | RAPID LEASING | SLOWER LEASING | |
| BASE CASE | 78,274 | 55,061 | 20,084 | 8,832 | 10,728 | 4,067 | 109,086 | 67,960 | 41,126 |
| UNADJUSTED BIDS | 48,985 | 35,545 | 20,084 | 8,832 | 10,728 | 4,067 | 79,797 | 48,444 | 31,353 |
| 2%/YEAR PRICE GROWTH | 78,274 | 55,061 | 26,632 | 13,762 | 15,801 | 7,143 | 120,707 | 75,966 | 44,741 |
| 6% DISCOUNT RATE | 73,528 | 54,916 | 29,267 | 16,068 | 17,999 | 8,944 | 120,794 | 79,927 | 40,867 |
| 2% PRICE GROWTH & 6% DISCOUNT RATE | 73,528 | 54,916 | 38,323 | 24,560 | 26,088 | 15,392 | 137,938 | 94,867 | 43,071 |
| PRICE SHOCK | 78,274 | 55,061 | 20,084 | 12,442 | 13,721 | 6,803 | 112,079 | 74,306 | 37,772 |
| 3-YEAR INCREASE IN DEVELOPMENT LAG UNDER RAPID LEASING | 63,980 | 55,061 | 15,943 | 8,832 | 10,728 | 4,067 | 90,651 | 67,960 | 22,691 |

NOTES: Base case assumes an 8% real discount rate, 1%/year price growth, $24/boe in 1/87, and a value decline that is a linear decline of the NEV per tract from 1.5 x (average tract value) to .51 x (average tract value) for rapid leasing and .50 x (average tract value) for slower leasing.
Unadjusted bids case determines the NEV using the actual bids for the years 1983-1986 (see text).
Price shock occurs in 2000 and causes an increase in rapid leasing from 200 to 400 tracts in 2000 and 2001, a permanent 59% increase in average tract value, and an increase of 325 total tracts leased.

TABLE 8a

ECONOMIC BENEFITS OF RAPID AND SLOWER LEASING PROGRAMS

CENTRAL AND WESTERN GULF OF MEXICO

$14.00 Case

| YEAR | NUMBER OF TRACTS LEASED: RAPID LEASING | NUMBER OF TRACTS LEASED: SLOWER LEASING | PRESENT VALUE OF ECONOMIC BENEFITS IN YEAR LEASED: RAPID LEASING ($ Millions) | PRESENT VALUE OF ECONOMIC BENEFITS IN YEAR LEASED: SLOWER LEASING ($ Millions) | PRESENT VALUE OF ECONOMIC BENEFITS IN 1987: RAPID LEASING ($ Millions) | PRESENT VALUE OF ECONOMIC BENEFITS IN 1987: SLOWER LEASING ($ Millions) |
|---|---|---|---|---|---|---|
| 1982 | 182 | 182 | 1,021 | 1,021 | 1,836 | 1,836 |
| 1983 | 1,029 | 200 | 5,852 | 1,137 | 9,156 | 1,780 |
| 1984 | 814 | 200 | 4,292 | 1,137 | 5,991 | 1,587 |
| 1985 | 604 | 200 | 2,991 | 1,137 | 3,712 | 1,411 |
| 1986 | 200 | 200 | 946 | 1,137 | 1,052 | 1,265 |
| SUBTOTAL: Tracts Leased in 1982-1986 | 2,829 | 982 | 15,103 | 5,571 | 21,747 | 7,879 |
| 1987 | 200 | 200 | 949 | 1,137 | 949 | 1,137 |
| 1988 | 200 | 200 | 950 | 1,067 | 880 | 988 |
| 1989 | 200 | 200 | 950 | 1,055 | 815 | 904 |
| 1990 | 200 | 200 | 949 | 1,055 | 754 | 837 |
| 1991 | 200 | 200 | 947 | 1,055 | 696 | 775 |
| SUBTOTAL: Tracts Leased in 1987-1991 | 1,000 | 1,000 | 4,745 | 5,368 | 4,093 | 4,641 |
| 1992 | 200 | 200 | 944 | 1,004 | 642 | 683 |
| 1993 | 200 | 200 | 939 | 990 | 592 | 624 |
| 1994 | 200 | 200 | 933 | 990 | 544 | 578 |
| 1995 | 200 | 200 | 926 | 957 | 500 | 517 |
| 1996 | 200 | 47 | 917 | 222 | 459 | 111 |
| SUBTOTAL: First 2829 Tracts Leased in Slower Program | | 2,829 | | 15,103 | | 15,034 |



TABLE 8a (cont.)

| YEAR | NUMBER OF TRACTS LEASED: RAPID LEASING | NUMBER OF TRACTS LEASED: SLOWER LEASING | PRESENT VALUE OF ECONOMIC BENEFITS IN YEAR LEASED: RAPID LEASING ($ Millions) | PRESENT VALUE OF ECONOMIC BENEFITS IN YEAR LEASED: SLOWER LEASING ($ Millions) | PRESENT VALUE OF ECONOMIC BENEFITS IN 1987: RAPID LEASING ($ Millions) | PRESENT VALUE OF ECONOMIC BENEFITS IN 1987: SLOWER LEASING ($ Millions) |
|---|---|---|---|---|---|---|
| 1996 | | 153 | | 919 | | 460 |
| 1997 | 200 | 200 | 907 | 1,206 | 420 | 559 |
| 1998 | 200 | 200 | 896 | 1,202 | 384 | 516 |
| 1999 | 200 | 200 | 883 | 1,197 | 351 | 475 |
| 2000 | 200 | 200 | 869 | 1,190 | 320 | 439 |
| 2001 | 200 | 47 | 854 | 278 | 291 | 95 |
| SUBTOTAL: Next 1000 Tracts Leased Slower Program | | 1000 | | 5,993 | | 2,542 |
| 2001 | | 153 | | 1,283 | | 437 |
| 2002 | 200 | 200 | 837 | 1,688 | 264 | 532 |
| 2003 | 200 | 200 | 819 | 1,689 | 239 | 493 |
| 2004 | 200 | 200 | 799 | 1,689 | 216 | 456 |
| 2005 | 200 | 200 | 778 | 1,687 | 195 | 422 |
| 2006 | 200 | 200 | 755 | 1,684 | 175 | 390 |
| 2007 | 124 | 200 | 453 | 1,680 | 97 | 360 |
| 2008 | | 200 | | 1,674 | | 333 |
| 2009 | | 200 | | 1,667 | | 307 |
| 2010 | | 200 | | 1,659 | | 283 |
| 2011 | | 200 | | 1,649 | | 260 |
| 2012 | | 200 | | 1,638 | | 239 |
| 2013 | | 200 | | 1,625 | | 220 |
| 2014 | | 200 | | 1,611 | | 202 |
| 2015 | | 200 | | 1,595 | | 185 |
| 2016 | | 171 | | 1,349 | | 145 |
| SUBTOTAL: Last 3124 Tracts Leased | 3,124 | 3,124 | 13,509 | 25,868 | 5,688 | 5,264 |
| TOTALS: | 6,953 | 6,953 | | 1987 PRESENT VALUE: | 31,528 | 22,840 |
| | | | | DIFFERENCE: | 8,688 | |

With these assumptions, an extra $41 billion to $45 billion of economic value are gained under more rapid leasing.

An additional advantage of rapid leasing is the flexibility that it allows in the actual rate of leasing. This was tested by including a ten dollar price shock in the year 2000 in the leasing scenarios. Prices are assumed to rise suddenly to over $37. It is assumed for purposes of analysis that such a price shock would result in doubling the rate of leasing to 400 tracts in the years 2000 and 2001 under areawide leasing, an increase in the average net economic value of 59 percent in all years following the shock, and an increase of seven percent in the total leasable resource resulting from additional tracts becoming economic at the higher price. These assumptions underestimate the gain in economic benefits after the price shock because they apply only to resources not yet leased at that time. Resources that had been leased in earlier years, but not yet produced, would also yield increased benefits to the economy following a price shock. One would expect that the ability of a more rapid leasing approach to bring the newly appreciated tracts into development at an earlier time would increase the economic gain from faster leasing. In this scenario, however, the gains from more rapid leasing are $38 billion, roughly $3 billion below the initial case. This results from the fact that, under the rapid leasing scenario, all of the remaining leasable resource would have been leased within three years after the price shock, while leasing continues until 2022 under the slower leasing program. Thus, the benefits from the greater net economic value per barrel after the shock apply to a larger proporton of the total currently leasable resource under the slower leasing program. In effect, the slower leasing program captures the additional benefits as a return on correctly speculating on the sudden increase in value in later years.

The initial case assumes that the development profile of a tract is the same under both leasing options. Some commentors have suggested that industry will be unable to explore and develop tracts leased under the areawide program in the same number of years as it had under earlier programs because developing the larger number of leased tracts would strain its resources. The final case inserts an additional three-year lag between leasing and development in the rapid leasing scenario in those years where the program results in a greater number of tracts being leased than are leased in the slower program. The gains from more rapid leasing are over $22 billion in this scenario.

The 1986 drop in oil prices raises the possibility of "low" oil prices for the rest of the decade, if not beyond, in contrast to the $24 per barrel scenario. Table 8a shows the economic benefits associated with a low price scenario, in which the price of oil in 1987 was set at $14 per barrel, increasing at a real rate of one percent per year thereafter. The analysis is similar to the initial case, with the following exceptions: the net economic value per barrel, leasable resources, and the number of tracts leased were all reduced to be consistent with Table 8 in Appendix F; and the pace of leasing in the rapid leasing scenario was slowed to 200 tracts per year starting in 1986. In addition, it was recognized that the oil price decline reduces the net economic benefits that will flow from the resources already leased in earlier years. To capture this effect, the value decline formula, with the variables consistent with the $14 case, was applied over the entire leasing period, 1982-2016. This understates the benefits from leasing in 1982-1985 by using oil prices and expected prices below their actual values in those years.



Under the scenario shown in Table 8a, the gains to the economy from more rapid leasing are over $8 billion. Most of this gain is from the earlier and more rapid leasing in the 1982-1985 period, but there is also a gain of over $2 billion from the earlier leasing and development of the resources remaining after 1985.

More rapid leasing typical of the areawide or focused-on-promising-acreage approaches in the Central and Western Gulf of Mexico provides substantial gains to the economy that would not be realized under the slower leasing typical of the tract selection approaches. The benefits from the more rapid pace of leasing range from $8-45 billion. The substantial nature of these gains holds up under a variety of economic assumptions. The gains are divided between three periods: $7 to $20 million from the accelerated leasing of the current program, about $2 to $10 billion from the earlier and more rapid leasing in the proposed program, and as much as $6 billion from the earlier leasing and development of all remaining resources after the proposed program expires.

E. <u>Future Effects of the Pace of Leasing</u>

An issue that arises in formulation of the third 5-Year OCS Leasing Program is the effect of offering tracts at different rates during the 1987-1992 period upon the rate and sequence of future investments in exploration and development and upon the resulting economic benefits. Both price expectations and the inventory of unleased tracts will be different in 1987 than they were in 1982. If expectations about future oil and gas prices are much lower in 1987-1992 and leasing must draw from an inventory that has been substantially depleted of promising new prospects, there would be less difference in the rate of investment under a slower pace of acreage offerings as compared to more rapid offerings. The total acreage leased could tend to be similar, since the amount of prospective unleased acreage at the time of each sale would be moderate. Under either restricted offerings or large offerings, however, both the Federal Government and investors must evaluate the whole area to find promising prospects. For restricted offerings to achieve investment results similar to larger offerings, the Government must also be able to identify all prospects ready for investment. Larger offerings allow flexibility for bidding to adjust to information produced in the months between the sale and the time at which the Government would select the limited acreage to be offered. Wider offerings also provide more flexibility to increase rapidly the amount of acreage leased if oil prices increase rapidly again. This could be particularly true if the administrative processes for restricted sales were to be accompanied by reduced administrative capacity (budget and manpower), placing constraints on increases in the acreage to be offered.

The differences in investments and resulting economic benefits under restricted and wider offerings would tend to increase whenever changing conditions caused a substantial inventory of prospects worthy of investment to accumulate amidst unleased acreage. Larger offerings would allow investments in lease acquisition, exploration and development to adjust quickly to changing conditions, leasing good prospects from the unleased inventory relatively sooner after their emergence than would restricted offerings.

The tract selection procedures of the 1970s made it difficult to increase the acreage offered when conditions warranted. The leasing experience of the 1970s shows that the longer the restriction in the availability of prospective acreage, the greater is the buildup of demand for investment and the greater the potential jump in the rate of investment when acreage is finally made available. The rapid increases in seismic evaluation, acreage leased and exploratory drilling in 1983 and 1984 could have been smoothed out over 5 or 6 years had more acreage been made available starting in 1976. It is ironic that the heavy investments in 1983 and 1984 came just as world oil prices were declining, putting much of this investment "out of phase" with potential returns. Had more acreage been made available in 1980 and 1981, the expected net economic value, the government revenue, and the expected private returns could all have been higher. Had it been available starting in 1976, before the peak in oil prices, many of the actual investments would have been more timely and would have yielded greater economic benefits, though government revenues in (nominal dollars, undiscounted) could have been somewhat less than they would have been in 1980.

In summary, effects on investments and economic benefits caused by differences in the pace of lease offerings will tend to be greater the more rapid and extensive are the changes in oil price expectations and geological knowledge in the future. Restricted offerings tend to perform adequately in a relatively stable world while wider offerings allow more flexibility for investments to adapt to changing conditions.

## IV. A Framework for Assessing Revenue and Fair Market Value Consequences

A substantial part of the controversy over more rapid OCS leasing has been the charge that it reduces Federal lease revenues and violates the requirement to assure receipt of fair market value. To address this concern, it is appropriate to review the relationship between the pace of leasing, the bidding for leases, the resulting revenues and the fair market value requirement. This section discusses these relationships.

These relationships are complicated by the fact that there are different forms of Federal revenue. The lease revenues include cash bonuses, rentals and royalties. The cash bonuses paid at the time leases are issued are the most well-known form. Rental fees are relatively small annual payments made by the lessee. Royalties are collected years after leases are issued, being a percentage of the value of the oil and gas produced. In addition to lease revenues, any profits lessees make contribute to the firm's taxable income and presumably its tax payments to the Federal Government. (Income tax revenues, of course, are collected by the Internal Revenue Service and are not accounted for on a lease-by-lease basis.)

The cash bonus paid for a specific tract can be affected by geologic and economic conditions that affect the tract's net economic value as well as conditions that affect the portion of its perceived value that firms are willing to bid. Since the pace of lease offerings in general can affect the time at which a tract gets leased and the state of knowledge about the geologic and economic conditions during which it gets leased, the pace can affect the tract's net economic value at the time it is leased. Similarly, the pace of leasing can affect the portions of tract values that firms bid. Thus the pace of leasing can cause the amount of bonus paid for a specific tract to be higher or lower.



The pace of lease offerings also affects the number of tracts leased in a given sale or period and, as discussed in sections II and III, the mix of tracts of different values that is leased. The total bonus revenues in a sale or period can be greater if more tracts are leased, or if higher value tracts are leased. It is possible for total bonus revenues to increase despite the fact that the bonuses for specific tracts are less than they could have been under different circumstances. The reverse is also true, namely that total bonus revenues can decrease while bonuses for specific tracts are more than they would have been.

Royalty and tax revenues can be affected by the pace of leasing because the pace, in part, determines the timing of the investments needed for production to occur. In general, these downstream revenues will occur earlier when leases are issued earlier. If the resource potential is confirmed by exploration and expectations of higher oil prices in coming decades are borne out by future events, the leasing of more acreage in the present means higher royalty and tax revenues from OCS leases in the period 5 to 25 years from the present.

In fact, differences in the pace of leasing mean differences in the timing of revenues of all forms. To assess the revenue effects of different leasing rates, it is necessary to account for the fact that having tracts leased in one period means they will not be leased (at least until relinquished) in any later period. Increased leasing in the present tends to shift the revenues to be derived from the Government's land forward in time at the expense of revenues in later periods.

Discounting to present value is the appropriate method for measuring the effects of such revenue shifts just as it is for assessing the effects of timing on economic benefits as discussed in Sections II and III. Discounting allows for the benefits of receiving revenues earlier to be weighed against decreases in the undiscounted amounts that may also result. For example, a $2 million bonus today is equivalent in present value terms (at an 8 percent discount rate) to a bonus of $2.7 million 4 years from today, and to a $3.7 million bonus 8 years from today. A $5 million bonus today is equivalent to a bonus of $6.8 million in 4 years and a $9.3 million bonus in 8 years. A bonus 9 years from today would have to be twice as much as a bonus today to be equal in present value terms.

Thus, in formulating a leasing program it is useful to analyze the extent to which various factors affect bonus bids and other forms of revenue. In particular, it is important to separate the revenue effects of perceived tract characteristics and economic conditions at the time at which leases are sold from the effects of the pace of leasing on the competitive bidding process. Furthermore, it is necessary to account for the effects of receiving revenues at different times under different leasing rates. Correctly analyzing these various effects is a complicated task.

The effects of the pace of leasing on the competitive bidding process may also affect assurance of fair market value. Appendix K sets forth the legal and economic meaning of the fair market value requirement and describes the policies and procedures now in effect for meeting that requirement. The primary concept is that the fair market value of a property is determined by reference to the price it would bring in a competitive market through transactions between knowledgeable and willing buyers and sellers. In the absence of market prices, or if the competitive process is so flawed that market prices cannot indicate fair market value, other means of determining or assuring fair market value are used. The MMS bid adequacy procedures are based on this concept.

Since the market price for an OCS lease is the highest competitively bid cash bonus the government receives, Federal bonus revenues are related to fair market value. However, the case law on fair market value makes clear that fair market value is a legal standard that establishes a minimum regarding what is acceptable for a lease but does not require maximization of revenues. (See, for example, California v. Watt, 712 F. 2d 584, U.S. Court of Appeals, District of Columbia Circuit, July 5, 1983.) Furthermore, because it is tied to market prices, the fair market value of a particular property can increase or decrease as conditions which affect market prices vary. Thus, substantial variation in Federal leasing revenues can occur as prices in the lease market change, without violation of the fair market value requirement.

In assessing the revenue and fair market value effects of the pace of leasing, it is important to distinguish between the factors that affect the market price of leases and the resulting Federal revenues without preventing assurance of fair market value, on the one hand, and factors that affect assurance of fair market value, on the other. Legally and technically speaking, concerns about meeting the fair market value requirement are limited to the adequacy of competition in cases for which competition is relied upon and the adequacy of the Government's tract evaluation and bid rejection policies in cases for which they are relied upon. In some cases, of course, both competition and tract evaluation are used.

The adequacies of competition and Government procedures can be analyzed and debated at length. Even if such analysis shows that leasing would be in technical compliance with the fair market value requirement, there is likely to be the perception that any failures on the Government's part to get as much as conceivable for leases are violations of the fair market value requirement. Thus, various means for increasing Federal leasing revenues can be considered, not only for their deficit reduction benefits but also for the increase they may yield in public confidence in the conduct of the leasing program.

If market prices competitively determined are the preferred measure of fair market value, then the issue arises, can the price at which properties are sold always be regarded as fair market value? More particularly, is any high bid received for an OCS lease to be regarded as fair market value? It has been argued that since the sealed bidding process is competitive, each bid submitted must reflect the possibility of competitive bids even if none materialize. This argument is supported by the concept of an equilibrium in the distribution of bids over the many tracts bid upon simultaneously. If a firm could identify a class of tracts for which the high bids would be substantially less than fair market value, it could reap more profit by shifting its bids into that class. The distribution of bids that results from many firms' efforts to find such situations tends toward an equilibrium in which the returns expected from all lease acquisitions tend to be similar.



A situation identified by the Commission on Fair Market Value Policy for Federal Coal Leasing, which argues against automatically using market prices as a standard for "fair market value," is monopolistic manipulation of the market. Any seller is a monopolist if it can exert control over a sufficient portion of the supply of a given commodity or property to influence the market price by changing the amount it offers for sale. A monopolist can cause prices to increase by withholding his supply or to decrease by offering more. Monopolists can restrict their output to extract higher profits from their customers. Dominant firms in a market, including monopolists, can "dump" their product at low prices to force competitors out of business. The issue thus arises as to whether market prices in a monopolistic market are adequate measures of fair market value. This issue needs to be addressed in OCS leasing because the Federal Government's dominant role in the supply of offshore oil leases raises the possibility that it could exert power over lease prices in a way similar to that of a monopolist. Arguments have been made that areawide leasing in effect drove down bids by "dumping" too much acreage on the lease market on the one hand and that tract selection leasing could increase prices by exercising monopoly power on the other.

The Coal Commission reviewed the case law on fair market value. It found that the courts have recognized that "the market price may not necessarily be determinative" of fair market value if there is "evidence that the market had been artificially depressed."[1] Since the Secretary, in leasing Federal coal, determines fair market value primarily by an appraisal based on prices in comparable sales, the Commission found that he "should take an active deliberative role in determining whether the sales in question were made under market conditions conducive to arriving at a fair price."[2] Of particular concern was whether "unrestrained leasing might have the effect of depressing an already 'soft' market, with the result that prices obtained in such a market may be below fair market value."[3] Appraisals based on prices in comparable sales that were below fair market value should, therefore, not be used to determine the fair market value of Federal coal leases. Similar concerns have been raised that areawide OCS leasing reduces competition and depresses OCS lease prices below fair market value.

The operation of a monopolistic lease market can be understood by comparison to the operation of an idealized competitive lease market. Fair market value is defined as the market price determined in a competitive market because such a market allows buyers and sellers to agree to transactions without compulsion and with knowledge from the market. An idealized competitive lease market would involve many sellers and many buyers, though not necessarily in every transaction. Such a market would have developed had the Government sold all, or at least most of, the OCS lands outright many years ago. If no single owner of OCS lands could affect lease prices in general by his decision to lease his oil and gas rights, then lease prices would be competitively determined and would be a good measure of fair market value.

1 Report of the Commission on Fair Market Value for Federal Coal Leasing, p. 619.
2 Ibid., p. 620.
3 Ibid., p. 622.

In an idealized competitive lease market, an OCS landowner could decide to withhold his leases to gain from the appreciation in value resulting from expected increases in oil and gas prices or decreases in costs. He would do so using the same rule of thumb as the idealized OCS manager described in Appendix F except that he would compare the rate of appreciation of the proceeds from sale of the tract with his own discount rate rather than the social discount rate. If an individual OCS landowner withheld his oil and gas rights, whether to his own benefit or detriment, it would not affect the prices of other oil and gas leases transferred in the market. Similarly, if an individual OCS landowner chose to lease all his land, it would not affect the prices of other leases. The competitive operation of the market would assure that prices were fair market value.

In comparison, an OCS owner with holdings sufficiently extensive to affect lease prices in general could cause lease prices to be higher or lower than the fair market values that would result from the idealized market. If he managed to imitate the supply of leases that would have resulted in an idealized competitive market, then lease prices would be the same as the competitive market lease prices and would be fair market value. To do so, however, would require that he exercise little restraint on the availability of his tracts for lease.

Despite the Government's position as the dominant seller of offshore leases, there are several fundamental limitations to its ability to exercise monopoly power. First is the fact that OCS leases are not bought for their inherent value to the buyer, but for the oil and gas which they may yield. The value of an OCS lease is derived from the expected value of the oil and gas which will be produced if found. The price of oil, in particular, is set by an international market which the United States alone has little ability to affect. The expected price of oil and gas is affected very little by the rate of OCS leasing. As a result, the Government cannot extract true monopoly profits by withholding leases and forcing both lease prices and oil prices to higher levels. The Government can, however, increase the price paid for each lease issued by delaying its sale during periods of rising price expectations. (Appendix F discusses the question of whether this practice is beneficial to the economy.) Although it might increase its bonus revenues from specific tracts leased in this manner, it is not necessary to do so in order to assure receipt of fair market value, just as it is not necessary to hold a stock while its value is appreciating in order to receive fair market value when it is sold.

The Government is also limited in its ability to cut lease prices. Firms "dumping" their products to inflict financial damage on their competitors (through so called predatory pricing) set prices below their competitors' costs. The Government, however, cannot set lease prices because it must use the sealed competitive bidding process. This means that, even if the Government wished to sell at an amount less than fair market value, any firm willing to pay just slightly more than the going price could enter a bid and win a lease. The profits firms could make by bidding enough to win such tracts but still less than fair market value would tend to attract more firms. Thus, any observable tendency for the market to underprice OCS leases would attract more bids and yield higher prices over time.



It is also worth noting that the OCS tract evaluation method does not raise the issue identified by the Coal Commission regarding fair market value determinations using below fair market value prices from comparable sales. The MMS tract value estimates are made by the discounted cash flow method which uses estimates of tract characteristics, future costs and future oil and gas prices to calculate the net value of the tracts after royalties and taxes. Bonuses bid for other oil and gas leases are not used in this method.

The issue of whether the pace of leasing affects receipt of fair market value thus boils down to two questions. The first relates to tracts for which there is evidence of competition in the submission of three or more bids. The question is whether either lease values or the competitive process is so affected by the rate of leasing that the high bid on such tracts can fail to be at least as great as the market price that would result from a transaction between knowledgeable and willing buyers and sellers. The second is whether the government's tract evaluations and bid rejections can assure receipt of fair market value on tracts for which there is less evidence of competition. These questions will be addressed below.

## V. Revenue and Fair Market Value Consequences of the Pace of Leasing

This section describes a number of analyses that have been performed on the effects of areawide leasing. First it examines the revenue tradeoffs inherent in the choice of faster versus slower leasing. In many transactions, the seller must choose between a certain and immediate sale at a lower price on the one hand and an uncertain later sale, perhaps at a higher or lower price, on the other. Since the Government retains a rental and royalty interest in tracts leased and stands to collect taxes on profits as well, this type of tradeoff involves consideration of the differences in timing of these revenues as well as of the bonus or cash price paid at the time of the lease sale. The analysis described below shows the gains that result from receiving all forms of revenue sooner because of the larger lease sales in 1983, 1984 and 1985 as compared to continued tract selection sales. Bonus decreases equal to such gains could be incurred without a net loss to the Treasury. In other words, this analysis shows the maximum decrease in bonuses that could have resulted from the areawide and focused-on-promising-acreage lease sales held in 1983 through 1985 while not costing the public financially.

Second, it describes a variety of analytical methods used to assess the extent of change in the bonuses paid for tracts leased that results from various causes. The approach is to analyze each cause-and-effect relationship itself to determine how sensitive tract values and bonuses are to each cause of change. This approach has been used to assess the likely bonus effects of the pre-sale nominations, oil prices, water depth, number of bidders, and the likely effects of larger lease sales on the number of bids received.

Third, this section describes the results of using statistical regression techniques to analyze data on changes in observable variables which are believed to be related. This approach uses mathematical techniques to determine the extent to which variations in one variable are associated with variations in another variable. By statistically controlling for the effects of other factors affecting bonuses, regression may be able to provide estimates of the change in bonuses associated with larger lease sales. This method has been used by the General Accounting Office to analyze the relationship between the bonuses paid for leases in both tract selection and areawide sales, and such factors as the size of the sale, oil and gas prices, resource potential, water depth, and the number of bids.

A. Tradeoffs in the Timing of Revenues

The large lease sales in the Gulf of Mexico during 1983, 1984 and 1985 resulted in much more acreage being leased than the historic rate. During 1983, 1984, and 1985, 2,447 leases were issued for $8.5 billion in the Central and Western planning areas. If the previous tract selection procedures had been used to offer these blocks, some of the blocks would not have been leased until 1994 or later. The Federal Treasury benefited from receiving those bonuses in 1983, 1984, and 1985 rather than receiving them over a longer period because revenue today is always more valuable than the same amount of revenue received in a later time period.

Although earlier receipt of a given amount is more valuable to the Treasury, the bonus paid for a given tract is not likely to be the same if it is leased in, say, 1983 as it would be if leased in 1986 or 1996. Even if competitive conditions were the same, economic conditions and expectations and geologic information would differ. The rate of leasing can affect the value of leasing revenues to the Treasury by changing the time at which specific leases are sold as well as the number of leases sold at one time. Thus, it is difficult to determine the precise benefit of leasing the 2,447 tracts leased in 1983-1985 as compared to leasing them at a slower rate over a longer period, particularly when a substantial part of the longer period still lies in the future. It is possible, however, to estimate how much more, on average, each block would have to receive if leasing proceeded at a slower pace in order to equal the value of the revenues received in 1983, 1984 and 1985.

From Table 1 it can be seen that the average rate of leasing in 1978 through 1982 in the Central and Western Gulf of Mexico planning areas under tract selection procedures was about 1.0 million acres a year. This translates into about 200 leases a year being issued. The leasing in 1983, 1984, and 1985 represents 12 years of leasing at 200 blocks per year. Bonuses in tract selection sales would need to be an average of $1.3 million more per block or $3.2 billion more in total for the bonuses to yield the same value to the Federal treasury as did the bonus revenue actually received in 1983, 1984, and 1985.

Even if bonuses had been $3.1 million more per block, as the GAO[1] estimated for tract selection sales, it would not be until 1989 (using an 8.0 percent discount rate) that the Federal Government would have received the same present value of bonus revenues. Figure 3 shows this effect. This graph shows the cumulative bonus receipts from the areawide sales held in 1983, 1984, and 1985 in the Central and Western Gulf of Mexico planning areas. The present value in 1983 of the bonuses received is $8.1 billion. Figure 3 also presents the cumulative present value resulting from leasing at approximately 200 tracts per year under the assumption that each tract received, on average, $3.1 million more than it actually did in the large sales held in 1983, 1984

[1]GAO, Early Assessment of Interior's Area-Wide Program For Leasing Offshore Lands, July 15, 1985.



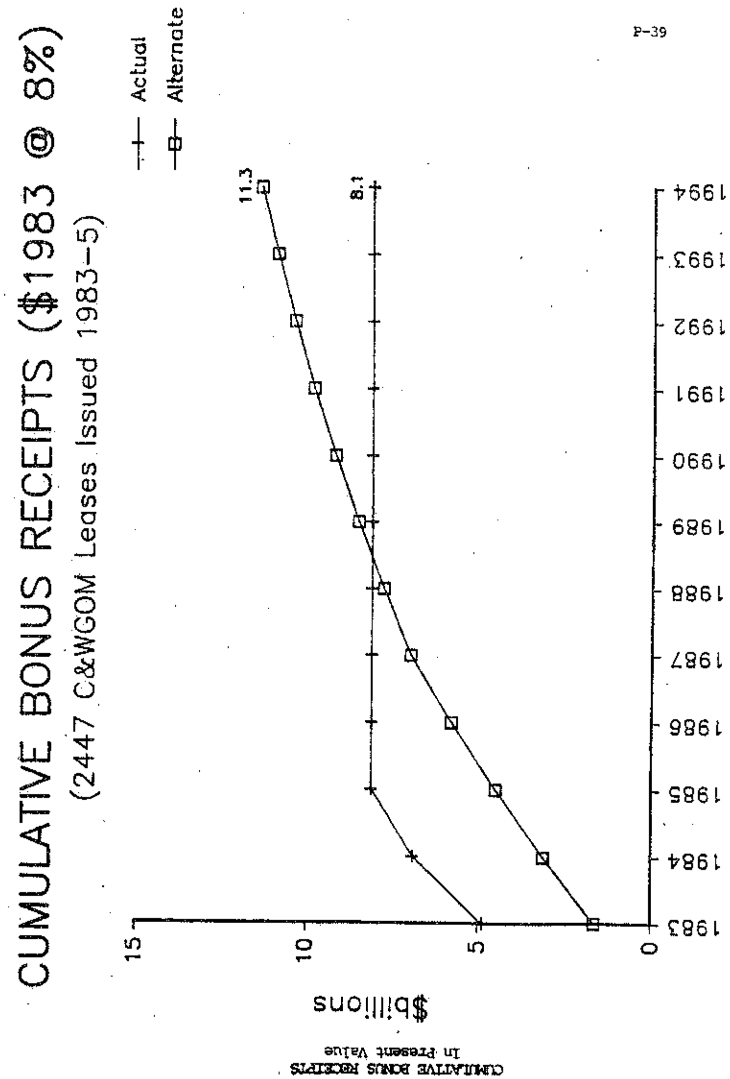



Figure 3

and 1985. By 1994, the 1983 present value would have been $11.3 billion, but the present value of the bonuses from a slower rate of leasing would not have equalled the actual value of the bonuses received until 1989. While the slower rate of leasing would eventually yield a greater total in present value if each tract drew $3.1 million more in bonus, other forms of revenue should also be considered.

The GAO report also found that changing oil prices have a large impact on the size of bonus bids. Due to the oil price decline of early 1986, had the government leased tracts at a slower rate over the 1983-1985 period, it would now be holding up to 2000 tracts worth only a fraction of their value in those years. Using, to the extent possible, the actual price path of oil, MMS compared the bonuses actually paid for the leases with what would have been paid in tract selection sales[1]. This analysis demonstrated that the area-wide and focus-on-promising-acreage program has increased the value of government receipts from offshore leasing on the order of $4 billion.

The Federal Government also receives royalties, corporate income taxes, and windfall profit taxes[2] from those leases that are productive. These revenues will also be received earlier by the Federal Government from earlier leasing of the tracts. The nominal value of these revenues may be increased or decreased depending on differences in prices and tax laws, but an estimate of the present value benefits from receiving them earlier can be made given certain assumptions.

The highest bonus any firm should be willing to spend for a lease is that residual value after royalties, taxes, and exploration and development costs which produces precisely an expected after-tax rate of return which is equal to the rate of return on the best alternative investment. Discounted cash flow models can estimate the residual values, royalties and taxes for specified tract characteristics. With an 8 percent discount rate and oil prices increasing slowly, the residual value of tracts typical of those being leased in the Gulf of Mexico has been estimated to be between 25-50 percent of total Government receipts, i.e., other Government receipts are estimated to be 1-3 times the expected residual value which can be paid as a bonus to lease the tract. Assuming other Government receipts will turn out to be 1.5 times the bonuses actually received, the total present value gain from leasing the 2,447 tracts in 1983, 1984, and 1985 instead of the 1983-1994 period is $5.3 billion in 1983.

Thus, because the Federal Government benefits from receiving revenues earlier rather than later, bonuses can be significantly less with earlier leasing and still have the present value of revenues remain the same as it would be with much higher bonuses received later. An analysis of this effect was done using discount rates of 6.0 and 8.0 percent and the assumption that other Government

[1]Marshall Rose, Response to General Accounting Office Comments Dealing with the Effect of Revenue Timing on the Value of Government Receipts in Areawide and Tract Selection Sales, May 16, 1986.

[2]The windfall profit tax is scheduled to be phased out between 1987 and 1990.



receipts are 1.5 times the higher bonuses received in later time periods under the 200 tract per year leasing rate. The bonuses from slower leasing would have to average at least $7.5 million more per tract than they did when leased in 1983, 1984, and 1985 for the two revenue streams to have the same present value. In other words, bonuses in the larger sales of 1983, 1984, and 1985 could be more than $7.5 million per tract lower than they would have been in tract selection sales over the 1983-1994 period without causing an overall loss to the Treasury. This is a "breakeven" amount of bonus reduction.

Lower bonuses, however, result in smaller write-offs against future Federal taxes. When one considers that lower bonuses would also result in higher taxes, these assumptions result in bonuses which would have to average in excess of $10 million more per tract in tract selection sales for equal present values.

Estimation Method

A number of specific assumptions were made in estimating the $7.5 million "breakeven" bonus reduction. It was assumed that the 1029 tracts leased in the Central and Western Gulf of Mexico areawide sales in 1983 would have been leased in tract selection sales over a five-year period at a uniform rate. Similarly, the 814 tracts leased in 1984 areawide sales would have been leased in tract selection sales from year five to year eight (assuming 1983 was year 0) at a uniform rate and similarly, the 604 tracts leased in the 1985 areawide sales would have been leased in tract selection sales from year 9 to year 11 at a uniform rate.

To simplify the analysis, it was also assumed that oil and gas prices and expectations were not changing abruptly over the leasing and production periods. As our 1986 experience indicates, this may not be the actual situation over the next 20 or 30 years. Nevertheless, this assumption has the advantage of focusing the analysis on the timing of receipts to the Treasury rather than on the timing of leasing vis a vis world oil price trends. While areawide leasing may well have achieved benefits to the Treasury by leasing many tracts earlier in a period of declining oil prices and oil price expectations, these benefits are not reflected in this analysis.

It was also assumed, for purposes of the initial analysis, that the lengths of time from lease issuance to exploration, development and production milestones were unaffected by the shift from tract selection to areawide leasing. If these time periods were increased by the buildup of firms' inventories of tracts, it could change both bonuses and other revenues. While both would be reduced, their relationship might change as well.

An equation was developed that would give an estimate of the amount by which average bonuses would need to be increased by leasing more slowly in tract selection sales for the total revenues from the leases issued in these sales to have the same present value to the Treasury as the total revenues from issuing the leases in the areawide sales of 1983, 1984, and 1985. The variables in this equation are:

PI = the ratio of other Government revenues (rental, royalty, and tax payments) to the bonuses at the break even level, i.e. PI multiplied by the bonus equals the present value of other Government revenues.

Omega = the increase in present value of taxes because of the effect on taxes from a lower bonus tax write off.

Delta = gain in bonus value per tract from earlier leasing during 1983, 1984, and 1985 in the Central and Western Gulf of Mexico planning areas. Average bonuses in tract selection sales would have to be higher by an amount equal to delta for the present values of the two revenue streams to be equal.

Delta is the solution to the following equation:

$$\text{Bonus}_{83} + \text{PI}*(\text{Bonus}_{83} + \text{Delta}*\#\text{tracts}_{83}) + \text{Omega}*(\text{Delta}*\#\text{tracts}_{83}) +$$

$$(1/1.08)*\text{Bonus}_{84} + \text{PI}*(1/1.08)*(\text{Bonus}_{84} + \text{Delta}*\#\text{tracts}_{84}) +$$

$$\text{Omega}*(1/1.08)*(\text{Delta}*\#\text{tracts}_{84}) +$$

$$(1/1.08)^2*\text{Bonus}_{85} + \text{PI}*(1/1.08)^2*(\text{Bonus}_{85} + \text{Delta}*\#\text{tracts}_{85}) +$$

$$+\text{Omega}*(1/1.08)^2*(\text{Delta}*\#\text{tracts}_{85}) =$$

$$\sum_{i=0}^{4}(1/1.08)^i*((1+\text{PI})*(\text{Bonus}_{83} + \text{Delta}*\#\text{tracts}_{83})/5) +$$

$$\sum_{i=5}^{8}(1/1.08)^i*((1+\text{PI})*(\text{Bonus}_{84} + \text{Delta}*\#\text{tracts}_{84})/4)$$

$$\sum_{i=9}^{11}(1/1.08)^i*((1+\text{PI})*(\text{Bonus}_{85} + \text{Delta}*\#\text{tracts}_{85})/3)$$

The left hand side of the equation is the present value in 1983 of the revenues from leasing in the Central and Western Gulf of Mexico during 1983, 1984, 1985. The first term, $\text{Bonus}_{83}$, is the actual amount of the bonuses received. The second term, $\text{PI}*(\text{Bonus}_{83} + \text{Delta}*\#\text{tracts}_{83})$, is the expected value of the other revenues (royalties, corporate income taxes, windfall profit taxes) the Government will receive. The $\text{Delta}*\#\text{tracts}_{83}$ is included since other Government revenues would not decline even if the Bonus declines. PI is the relationship of other Government revenues to the full residual value of a tract. The third term, $\text{Omega}*(\text{Delta}*\#\text{tracts}_{83})$ is the increase in corporate income taxes as a result of a lower bonus of the amount Delta. An Omega of .2 results from a 46 percent marginal tax rate, a write off after 5 years for 70 percent of the tracts which will be non-productive, and a write off over a typical production period for the 30 percent of the tracts which might be productive. Assumptions that more than 70 percent of the tracts will be non-productive would lead to an Omega higher than .2. The other terms of the left hand side of the equation are the same variables for the tracts leased in 1984 and 1985 and discounted to 1983. The terms on the right hand side of the equation represent the present value of Government revenues if they were received over a 12-year period. The first term,

$$\sum_{i=0}^{4}(1/1.08)^i*((1+\text{PI})*(\text{Bonus}_{83} + \text{Delta}*\#\text{tracts}_{83}))/5)$$

is the present value of the revenues from the tracts leased in 1983 assuming they were leased uniformly from 1983 through 1987. The next term is the present value of the revenues from the tracts leased in 1984 assuming they



were leased uniformly from 1988 through 1991. The last term is the present value of the revenues from the tracts leased in 1985 assuming they were leased uniformly from 1992 through 1994.

<u>Results</u>

Table 9 presents different values of Delta under varying assumptions. Values of Delta of $4.2 to in excess of $15 million per tract are reasonable estimates of how much lower bonuses could be on average under the leasing rates of 1983, 1984, and 1985 and still have the present value of Government revenues be the same as the present value of Government revenues under the leasing rates of tract selection sales. As stated above, a value of .2 for Omega assumes a very high rate for the percent of productive tracts. The bonus is written off very slowly for productive tracts which results in a small present value change in tax revenues. The assumption of 1.5 for PI is also at the low end of estimates of the current relationship between other revenues and the residual value. Changes in the timing of exploration, development and production might reduce PI, however.

Table 9

Estimates of Breakeven Bonus Reductions
Central and Western Gulf of Mexico Leases
Issued in 1983, 1984 and 1985

| Ratio of Other Revenues to Bonuses (PI) | Fractional Increase in Tax Revenue from Lower Bonuses (Omega) | Required Increase in Average Bonus (Delta) (in $ million per tract) | |
|---|---|---|---|
| | | 6% Discount | 8% Discount |
| 0 | 0 | .9 | 1.3 |
| .5 | 0 | 1.7 | 2.4 |
| 1.0 | 0 | 2.7 | 4.1 |
| 1.5 | 0 | 4.2 | 7.5 |
| 2.0 | 0 | 6.7 | 16.3 |
| .5 | .2 | 2.4 | 3.6 |
| 1.0 | .2 | 4.2 | 7.5 |
| 1.5 | .2 | 7.6 | 21.3 |
| 2.0 | .2 | 16.7 | N/A |

B. <u>Factors Affecting Lease Prices</u>

Some factors have been identified through which areawide leasing might affect the amounts bid for leases. These include the reduction in information gleaned by bidders from the nomination and tract selection process and the effects of firms' budget limitations. In addition, changes in the characteristics of the tracts being bid upon can affect the amounts bid as can changing oil and gas price expectations.

Some comments on the current 5-year program have argued that the modification of the nomination process reduces the amount of information available to prospective bidders and thereby reduces competition and the amount that a firm will bid for a lease. The empirical evidence that has been cited to support this claim is the decline in the average bonus per acre for leases in the Gulf of Mexico along with a decline in the average number of bids per tract. A decline in average bids could result from many other causes as well, such as changes in price expectations or leasing of more lower value tracts.

The role of tract nominations in bids does not seem to be substantial. Oil exploration is inherently risky. With current technology, the only way to eliminate (or at least significantly reduce) geologic uncertainty is to drill. Historically, over 85 percent of all exploratory wells in the Gulf of Mexico have been dry. The information whether somebody has nominated a tract does little to change the perceived riskiness associated with the value of a lease. At most it might affect slightly the perceived risk about the geologic conditions, but it can do nothing to change the other risks associated with exploring for oil and gas.

Historically in the Gulf of Mexico, many millions of acres have been nominated for each sale. The names of companies submitting nominations were made public but the tracts nominated by a specific company were never made public. The information released was a map specifying the tracts nominated and whether they had high, moderate, or low numbers of nominations. In the Gulf of Mexico, the map generally only indicated moderate and low levels of nominations as generally only 1-4 nominations were received. In addition, if companies specified general areas instead of specific tracts in their nominations, the information was not used. This practice diluted whatever value a nomination may have to a bidder. The information that a particular tract has been nominated by someone is of minimal, if any, value to potential bidders in reducing the geologic uncertainty of oil and gas exploration efforts given the inherent risk in exploration. A firm is not going to bid on a tract just because someone has nominated the tract or because the MMS has looked at the geology, looked at the nominations, and selected the tract to be offered in a lease sale. Before making a bid, a firm will collect and analyze geologic and geophysical information,[1] make projections about future oil and gas prices and future development costs if oil and gas are discovered, and estimate the present value of expected profits from exploration and development. Such analysis is substantially more detailed than the information that can be gleaned from the fact that a tract was nominated by another firm. A firm may analyze a tract it otherwise might not if it receives several nominations, however. But given the extent of masking that firms may do when they nominate tracts, it is difficult to judge how important this might be.

Tract selection, by limiting the acreage that was offered for lease, might have lead potential bidders to study some of the tracts to be offered more intensively than the tracts not to be offered, thereby gaining information on the tracts offered that they may not have had otherwise, but the mere fact that Interior selected tracts to be offered conveys little, if any, information.

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1 MMS also makes lessees' geological and geophysical information available to the public after an initial period of confidentiality. 30 C.F.R. 250.3. Making this information available likely does more to reduce risk than having tract nominations.



Some comments suggest that the limited budgets available for bidding can also reduce competition when the pace of leasing is high. Limited budgets do not, in themselves, reduce competition, however. Limited budgets only make people or firms allocate their budgets to items which give them the greatest return. In fact, the basic tenets of modern economics are that all budgets are limited and tend to be applied to items anticipated to provide the greatest returns.

The substitutions that result from budget and resource limitations are highly desirable, however. Market allocation and economic efficiency are facilitated by these substitution possibilities. Firms have the option of investing in oil exploration, whether onshore or offshore, on public or private lands, or even in other countries. They also have the option of investing in non-exploration activities. If they choose not to invest in offshore leases, it means that they believe the investment opportunities are better elsewhere. Restricting the acreage available for leasing reduces the ability of the U.S. economy to invest in those domestic projects yielding the highest return and may encourage investment abroad.

An important trend in leasing in the Gulf of Mexico is the shift to acreage in deeper water. As Table 10 shows, this trend accelerated with the implementation of areawide leasing which offered much more deep water acreage. This trend shows a potential for substantially increased investment in exploration and development because of the higher costs of drilling in deep water. It also demonstrates the success of areawide leasing in widening the search for oil and gas.

One of the most important determinants of the value of oil and gas leases is the expected future price of oil. Table 11 presents estimates of tract values calculated by a discounted cash flow evaluation model for several different types of tracts using prices of oil and gas and exploration factors which were used in bid adequacy determinations in past sales in the Gulf of Mexico. The tract value estimates depend on the many other assumptions used, but it is clear that expectations about the future price path for oil and gas strongly influence what the bonus bids will be for any given assumptions about the quantity of the resource expected, and the cost of exploration and development, which in the Gulf of Mexico basically depends on water depth and the depth of the productive horizon. High cost prospects are particularly sensitive. A reduction in the rate of price increase from .02 to zero at $33 per barrel reduces the high cost tract values by 58 to 69 percent. Reduction from $33 to $28 per barrel at zero increase reduces high cost tract values by 57 to 86 percent.

As discussed in section III, tract values are affected by the pace of leasing because of the resulting effects on the characteristics of tracts remaining in the unleased inventory. The value of individual tracts can appreciate if they go unleased while oil and gas price expectations increase or favorable geological data emerge. Value of individual tracts can also depreciate if price expectations decline or unfavorable geologic data emerge. If numerous tracts are appreciating during a period, but fewer are being leased, the resulting inventory buildup will yield higher bids on the selected tracts leased. More rapid leasing after a period of inventory appreciation and buildup will tend to reduce the amounts bid as additional tracts are leased in successive sales. This draw-down effect is accentuated to the extent that more moderate-to-low value tracts are leased during the same period.

Table 10

Leasing by Water Depth
Gulf of Mexico OCS Lease Sales
9/80 through 11/85

| Sale | (Date) | Total | Less Than 200 Meters | 200-400 Meters | Greater Than 400 Meters |
|---|---|---|---|---|---|
| | | Number (Percent) of Tracts Leased by Water Depth | | | |
| A62 | (9/30/80) | 116 (100%) | 106 (91%) | 4 (4%) | 6 (5%) |
| 62 | (11/28/80) | 67 (100%) | 64 (96%) | 0 (0%) | 3 (4%) |
| A66 | (7/21/81) | 156 (100%) | 147 (94%) | 4 (3%) | 5 (3%) |
| 66 | (10/20/81) | 102 (100%) | 91 (89%) | 9 (9%) | 2 (2%) |
| 67 | (2/9/82) | 115 (100%) | 97 (84%) | 10 (9%) | 8 (7%) |
| 69 I | (11/17/82) | 56 (100%) | 50 (89%) | 4 (7%) | 2 (4%) |
| 69 II | (3/8/83) | 11 (100%) | 11 (100%) | 0 (0%) | 0 (0%) |
| 72 | (5/25/83) | 623 (100%) | 490 (79%) | 72 (12%) | 61 (10%) |
| 74 | (8/24/83) | 406 (100%) | 309 (76%) | 55 (14%) | 42 (10%) |
| 79 | (1/5/84) | 156 (100%) | 109 (70%) | 24 (15%) | 2 (15%) |
| 81 | (4/24/84) | 453 (100%) | 258 (57%) | 30 (7%) | 165 (36%) |
| 84 | (7/18/84) | 361 (100%) | 221 (61%) | 61 (17%) | 79 (22%) |
| 98 | (5/22/85) | 409 (100%) | 275 (67%) | 14 (4%) | 120 (29%) |
| 102 | (8/14/85) | 195 (100%) | 118 (60%) | 19 (10%) | 58 (30%) |
| 94 | (12/18/85) | 38 (100%) | 29 (76%) | 5 (13%) | 4 (11%) |
| 104 | (4/30/86) | 101 (100%) | 61 (60%) | 3 (3%) | 37 (37%) |
| 105 | (8/27/86) | 41 (100%) | 31 (75%) | 2 (5%) | 8 (20%) |



Table 11

Estimates of Private Tract Value Under Various Price Assumptions

| Oil Price Assumptions | | | Tract Value Estimates ($ millions) | | | | |
|---|---|---|---|---|---|---|---|
| | | | Deep Water | | | Shallow Water | |
| | | | Resource Size | | | Resource Size | |
| Evaluation Date | Starting 1/ Oil Price | Price 2/ Change | High | Medium | Low | Medium | Low |
| 07/21/81 | $33 | 0.02 | $47.5 | $27.0 | $10.6 | $17.8 | $5.6 |
| 10/20/81 | 35 | 0.01 | 37.9 | 20.6 | 6.5 | 16.2 | 5.0 |
| 02/09/82 | 35 | 0.00 | 24.3 | 11.4 | 0.8 | 12.6 | 3.6 |
| 11/18/82 | 33 | 0.00 | 19.8 | 8.5 | -0.9 | 10.6 | 2.8 |
| 05/25/83 | 28 | 0.00 | 8.5 | 1.2 | -5.0 | 5.6 | 0.8 |
| 08/24/83 | 29 | 0.0067 | 18.2 | 7.6 | -1.2 | 8.6 | 2.0 |
| 01/05/84 | 30 | 0.0067 | 20.7 | 9.2 | -0.2 | 9.7 | 2.4 |
| 04/24/84 | 31 | 0.0067 | 23.2 | 10.8 | 0.8 | 10.8 | 2.8 |
| 07/18/84 | 30 | 0.01 | 24.8 | 11.9 | 1.3 | 10.8 | 2.8 |
| 05/22/85 | 28 | 0.01 | 19.5 | 8.5 | -0.7 | 8.6 | 1.9 |
| 08/14/85 | 26 | 0.01 | 14.2 | 5.1 | -2.7 | 6.4 | 1.1 |
| 12/18/85 | 21 | 0.02 | 10.9 | 3.3 | -3.4 | 3.4 | -0.1 |
| 04/30/86 | 16 | 0.03 | 5.7 | 0.3 | -5.0 | -0.2 | -1.7 |
| 08/27/86 | 14 | 0.03 | -0.4 | -3.6 | -7.4 | -2.6 | -2.7 |

Assumptions used:
Geologic Risk = 0.1
Conditional barrels of oil equivalent by resource size (millions) are:
  Deep Water--high 120, medium 80, and low 50
  Shallow Water--medium 30, and low 12
Number of tracts per field are assumed to be 4 in deep water and 2 in the shallow water area.
Deep Water is equivalent to 400 meters water depth.
Shallow Water is equivalent to 100 meters water depth.

1/ Starting prices specified to nearest whole dollar.

2/ Annual price change parameters for 1985 and 1986 sales are an approximation of a new two-part distribution of price changes employed in the evaluation model.

The issue that arises in formulation of the third 5-year OCS Leasing Program is the extent to which the pace of leasing under different procedures that could be used in that program would influence lease prices and the assurance of fair market value. Restricted lease offerings that would not offer all of the tracts that could be leased in a particular sale would tend to yield higher average lease prices because fewer low valued tracts would be included in the average. They would also tend to yield higher average bids to the extent that appreciation in the value of tracts occurs while they are withheld from leasing because of increasing expectations regarding oil prices or resource potential. While a higher average value is not necessary for technical compliance with the fair market value requirement, it might provide a higher level of public confidence. On the other hand, continuation of more rapid leasing over the long run would tend to yield prices similar to those of an idealized private OCS market that would clearly be regarded as yielding fair market value. This would yield revenues to the Federal Treasury which are higher in present value, though they might be lower in nominal value.

The actual rate of leasing that would result from continuing larger offerings would be determined by the same factors that would influence transactions in a private lease market, namely buyers' and sellers' geologic knowledge and expectations about economic conditions and oil prices. As our 1986 experience shows, when oil price expectations drop, the amount of acreage leased drops, even if large amounts are offered. When higher prices are expected, more acreage will get leased.

Ironically, in OCS leasing, the potential to drive down bids by offering large amounts of acreage, if it exists at all, could only result after a substantial inventory of valuable unleased prospects had been accumulated over a period of restricted leasing. Continued offerings of substantial acreage could assure that the government would never build up an inventory of leasable tracts large enough to have a depressing effect on bids. While the amount of acreage offered by continuing large sales might be substantial, the amount of prospective acreage considered by bidders and bid upon is likely to decrease substantially from 1983-1985 levels as the inventory is drawn down. The longer such leasing occurs while oil price expectations are declining or stable, the smaller will be the acreage actually leased, even from large sales.

C. Assessment of Competition Effects

Prices in a competitive market are good measures of fair market value because the interaction of many sellers and many buyers assures freedom of choice and provides a source of knowledge. Any seller can turn down an offer from one buyer if he thinks he can do better from another. Any buyer can search for the property and price that meet his needs, using knowledge gained from observing transactions as a guide. Competition helps make buyers and sellers willing and knowledgeable.

Competitive sealed bidding for OCS oil and gas leases provides a competitive process among buyers to assure that each Federal lease is sold to the firm that is willing to pay the most. Competition for OCS leases is usually measured by the number of bids submitted for a tract. In general, criticism of the competitive effects of rapid leasing has been based on the belief that firms bid more if they face more competing bidders on a tract. People



generally have more confidence that the high bids on OCS tracts are fair market value if there are more bids on each tract. Thus, there is concern that areawide leasing, by spreading the same number of firms with their limited budgets over many more tracts, has thinned competition and allowed firms to reduce their bids below fair market value without increasing the risk of being outbid.

To assess the effect of competition in past and future lease sales of various types, it is useful to examine in more detail the relationship between the number of bids received and the amount of the high bid on a tract. Figure 4 shows strong evidence of a correlation between the number of bids and the amount of the high bid. It is not clear, however, whether and to what extent this occurs because more bids cause firms to bid greater amounts or because more valuable tracts attract both higher bids and more bidders. It is useful to examine both the theory of bidding on properties of uncertain value and some data from leasing experience to assess these relationships.

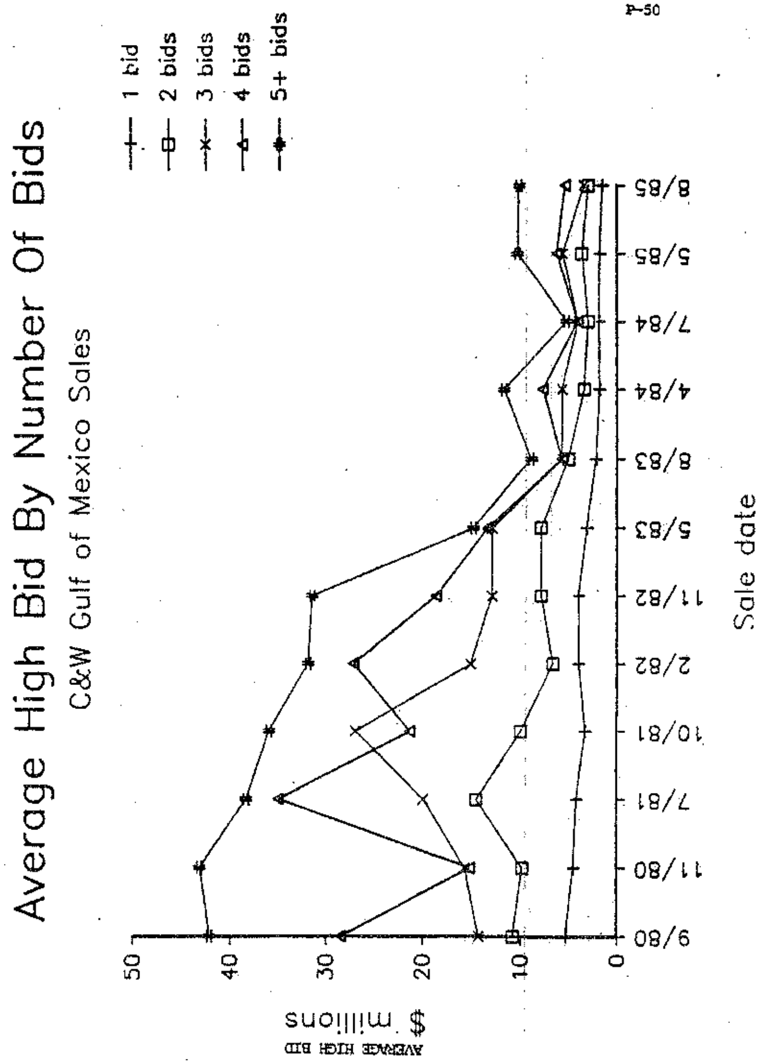
Theoretical studies of bidding behavior suggest that the desirable competitive effects of an auction are realized when there are three knowledgeable bidders. These studies suggest that when any bidder anticipates more than three bidders, the income maximizing bidding strategy is to offer a lower bid than he would offer if he only anticipated two other bidders. Failure to make this adjustment increases a firm's chances of winning the tract by being the most over-optimistic bidder. At least theoretically, a firm would not increase its bid for a tract if it expected more competing bids. Under this bidding strategy, more bidders for a lease would still result in a higher high bid, but because of a statistical effect rather than because of competition forcing each bidder to bid higher. It occurs because the greater the number of firms estimating the value of a tract, the higher the highest estimate tends to be.[1]

The concept that firms don't bid a higher fraction of their estimate of a tract's value when confronted by more than two other bidders provides a general theoretical underpinning for the three-bid rule used in MMS bid adequacy determinations. When there are three or more bidders for a block, it can be expected that the high bidder has bid the most that competition can bring him to bid. The high bid is therefore reflective of the competitively determined fair market value.

Different levels of competition are to be expected in bidding for items with uncertain value such as oil or gas leases. Two firms evaluating a tract are likely to interpret the geologic information differently and place different values on the tract. For tracts of marginal potential, it is likely that the evaluations by most firms would be less than the minimum submissible bid. For tracts of more promising potential, more firms' evaluations would be above the minimum bid. One would therefore expect more bids on more promising prospects than for more marginal prospects. One would also expect a greater fraction of the tracts to draw only one bid if there were a greater fraction of lower value tracts in the sale.

1 For a fuller discussion of the theory of bidding see James Ramsey, Bidding and Oil Leases, JAI Press Inc., 1980; and Albert Smiley, Competitive Bidding Under Uncertainty: The Case of Offshore Oil, Ballinger Publishing Company, 1979.

Figure 4






The evidence from Sales 72, 74 and 79 in the Gulf of Mexico supports the concept that it is the better prospects which receive the greatest number of bids. In January of 1981, the Department issued a Call for Nominations for these sales. Thirty companies submitted nominations on 15.5 million acres. In April of 1981, the Gulf of Mexico offices of the U.S. Geological Survey and the Bureau of Land Management developed recommendations for the selection of tracts to be offered. Their recommendations were developed using the approach employed for previous tract selection sales. In the past, almost all of the tracts selected for a sale were nominated, but not all nominated tracts were offered for lease. The tracts which were thought to have the most promising potential were selected. The concept of areawide leasing was adopted after the BLM and USGS made their recomendations for the tract selections in Sales 72, 74 and 79. Those recommendations were not used to configure lease sales. The recommended tracts were offered as part of areawide lease sales. Bidding on these tracts can be used to test the argument that the relatively more attractive and more obvious prospects attract more bids.

Table 12 shows the average bonus bid and percent of one-bid tracts for selected tracts and others. The average bonus on the tracts receiving bids which both agencies recommended to be included in Sales 72, 74, and 79 was twice the average bonus on the tracts receiving bids which neither agency recommended be included in the sales. This higher average reflects the bidders' perception that these tracts have higher potential. There were substantially more one-bid tracts in the set of tracts neither agency recommended be included. Since the recommendations of the field offices of the USGS and BLM of tracts to be included in the sales were never made public, they could not have influenced the bidding. However, since industry interest was focused on these better tracts, it indicates that the better prospects are more often identified by several firms. The marginal, more risky prospects are detected by few firms or only one firm.

The bidding distributions in Alaska OCS lease sales indicate that areawide leasing has not affected competition in those sales. Three sales have been held in the planning areas in the Bering Sea: Sale 57 in Norton Basin in 1983, Sale 70 in St. George Basin in 1983, and Sale 83 in Navarin Basin in 1984. Each of these sales were the first sales ever held in these planning areas. The Norton and St. George sales were tract selection sales offering 418 and 478 tracts respectively, while the Navarin sale was an areawide sale offering 5,036 tracts. The percentage of tracts receiving three or more bids in the Navarin sale, however, was more than twice the percentage in either the Norton or St. George sale. Table 13 shows the bid distributions for those three sales.

Both the current estimates and the estimates made in 1982 of the resource potential of the Navarin Basin are higher than the estimates of potential for either St. George or Norton so the above distribution again suggests that higher potential tracts receive much greater competition than lower potential tracts.

The bidding in the Beaufort Sea again contradicts the hypothesis that areawide leasing has caused a significant increase in tracts receiving few bids. There is little difference in the bidding distributions for tract selection Sale 71 which offered 338 blocks in 1982 and areawide Sale 87 which offered 1475 blocks in 1984. Table 14 shows the bid distributions for those two sales.

Table 12

Comparison of Bidding on Selected and Non-Selected Tracts
Gulf of Mexico First Areawide Sales

Sale 72

| | Average bonus ($ million) | Percent 1-bid tracts |
|---|---|---|
| Recommended by both BLM and USGS | 9.6 | 56 |
| Recommended by neither BLM or USGS | 4.7 | 71 |

Sale 74

| | Average bonus ($ million) | Percent 1-bid tracts |
|---|---|---|
| Recommended by both BLM and USGS | 6.3 | 44 |
| Recommended by neither BLM or USGS | 3.1 | 64 |

Sale 79

| | Average bonus ($ million) | Percent 1-bid tracts |
|---|---|---|
| Recommended by both BLM and USGS | 3.1 | 47 |
| Recommended by neither BLM or USGS | 1.3 | 84 |



Table 13

Distribution of Bids in Alaska OCS Sales

Number of Tracts (Percent)

| | Norton (tract selection) | St. George (tract selection) | Navarin (areawide) |
|---|---|---|---|
| 1 bid | 44 (69) | 63 (65) | 85 (46) |
| 2 bids | 10 (16) | 19 (20) | 40 (22) |
| 3 bids | 6 (9) | 11 (11) | 23 (12) |
| 4 bids | 4 (6) | 4 (4) | 15 (8) |
| 5 or more | | 23 (12) | |

Table 14

Distribution of Bids in Beaufort Sea Lease Sales

Number of Tracts (Percent)

| | Sale 71 (tract selection) | Sale 87 (areawide) |
|---|---|---|
| 1 bid | 71 (57) | 121 (52) |
| 2 bids | 24 (19) | 52 (22) |
| 3 bids | 9 (7) | 34 (15) |
| 4 bids | 7 (6) | 20 (9) |
| 5 or more | 14 (11) | 5 (2) |

The three areawide sales in the Atlantic provide little evidence of the competitive effects of areawide leasing because there is currently limited interest in the Atlantic. Only 40 tracts received bids in Sale 76 in the Mid-Atlantic in 1983, only 11 tracts received bids in Sale 78 in the South Atlantic in 1983, and no bids were received at all for the proposed Sale 82 in the North Atlantic in 1984. Factors such as moratoria, threat of litigation, and the Canadian boundary dispute also contributed to the lack of interest in Sale 82.

The Gulf of Mexico lease sales provide the best evidence of the relationship between the number of bids on OCS tracts and their value. Figure 4 shows the average value (high bid amount per tract) at each level of competition for the sales from A62 in 1980 through 102 in 1985. If a thinning of competition caused by areawide leasing was the dominant cause of lower bids, then one would expect to find a substantial decline in amounts of bids on tracts receiving fewer bids with the implementation of areawide leasing, while tracts receiving more bids kept their value.

As Figure 4 shows, however, the relationship between the number of bids and the amount of the high bid does not follow this pattern. Instead, the value of the tracts receiving a relatively high number of bids (5 or more) has been declining since the peak in late 1980 despite the evident intensity of competition. The 4- and 3-bid categories also show declines that began well before areawide leasing began. The amounts bid on 1- and 2-bid tracts have declined somewhat as well, but not nearly as much as the 5-or-more-bid tracts. It is clear from Figure 4 that the resource and economic characteristics of the tracts leased in each bid category and each sale are affecting the high bids received, lowering the value of tracts in later sales even on tracts for which competition remains high.

The declining number of highly competitive tracts evident in Figure 5 is consistent with the drawdown of an inventory in a series of sales that tend to lease higher value tracts earlier. This is not to say that areawide leasing beginning in 1983 has had no effect on the patterns of competition. It does suggest, however, that a substantial part of the decline in average bids is caused not by a decline in the number of bids, but by a decline in the economic value of the leases being sold.

Figure 5 shows the change in patterns of competition for leases in Gulf of Mexico sales from Sale A62 in September 1980 through Sale 102 in August 1985. It is clear from the one-bid bars and those for four and five-or-more bids that there has been a shift, increasing the fraction of tracts receiving only 1 bid and decreasing the fraction of tracts receiving four or more bids. This trend, however, does not begin with the first areawide sale, Sale 72. It begins two years earlier in 1981 with Sale A66. The increases in the fraction of one-bid tracts at the onset of areawide leasing are no more dramatic than those in 1981 and 1982 sales. These trends are consistent with a series of sales of declining quality properties in which the patterns of competition are strongly affected by the mix of tracts of different value being bid upon. Areawide leasing differed from tract selection leasing primarily by offering a greater number of moderate to low value tracts. However, declining oil and gas price expectations in 1981 and 1982, coupled with the leasing of over 2 million acres of prospects that tended to be above the average prospects in the Federal unleased inventory, reduced the number and value of the superior prospects remaining to be leased. If patterns of



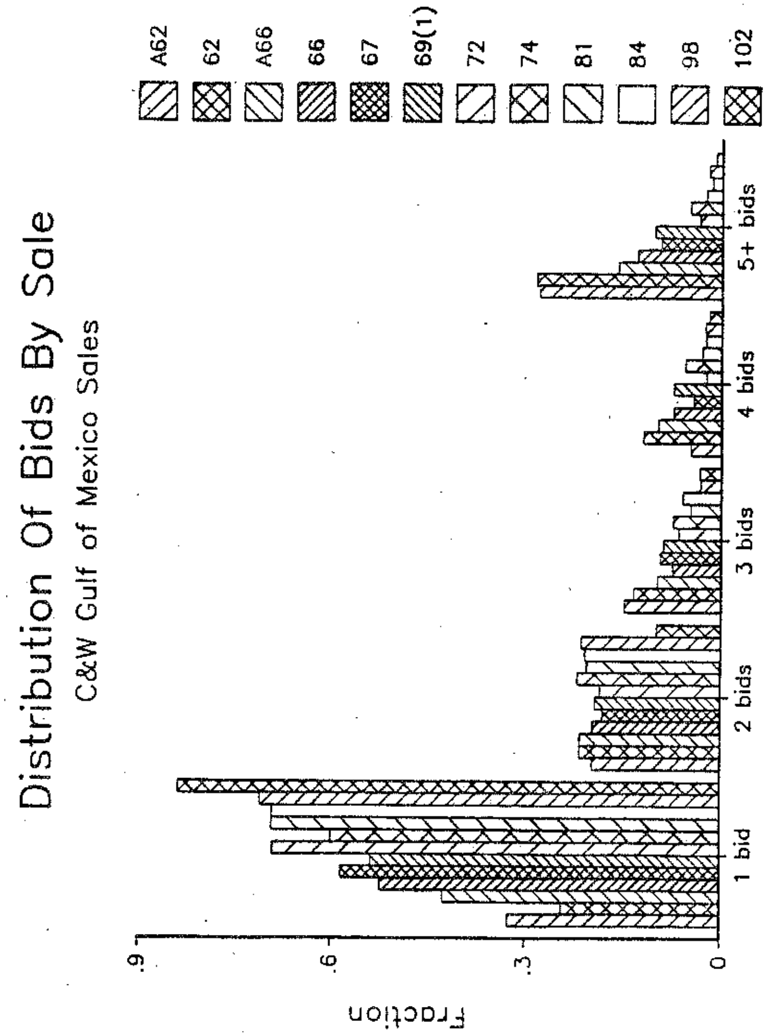



Figure 5

competition are strongly affected by the value mix of tracts offered, then the trend toward a mix of more moderate and low valued tracts with fewer and more moderately valued high value tracts would be consistent with the trends in competition shown in Figure 5.

For the third 5-year leasing program, the patterns of competition will be affected by the value mix of tracts offered. If areawide or tract selection procedures result in a similar mix of tracts because unleased prospects are ripening slowly, then competition is not likely to be very different.

Similarly, if areawide leasing or focused leasing is used and prospects ripen more quickly but are leased as they become worthy of investment, then tract values as a whole will not grow very great and competition will be similar to that resulting under conditions leading to slower ripening. Competition may be shifted toward higher numbers of bids on more tracts, however, if tract selection procedures are used and acreage is not offered until its value has appreciated substantially. The higher levels of competition achieved in this situation would tend to reduce reliance on the government's tract evaluations and build public confidence that fair market value was being received.

## D. Statistical Analysis of Factors Affecting Competition and Bonuses

Earlier sections of this Appendix have presented a conceptual framework for assessing the private investment, Government revenue, and fair market value consequences of the pace of leasing. Additionally, factors affecting bonus bid and competition levels were presented and discussed. Data documenting some of these factors were presented in tabular and graphical form. While these techniques are useful for discerning trends and assessing the relationships between factors, they are less useful for measuring the independent effects of the many variables which are likely to influence competition levels and bonus bids. This section discusses a statistical technique for identifying the individual effects of these influences, as well as empirical applications of this technique to explanation of high bid and competition levels.

The fundamental issue is whether and to what extent the shift to areawide leasing in 1983 caused the decreases that have been observed in average bonuses and the average number of bids per tract. Statistical regression analysis is a well accepted method for measuring the extent to which such changes are associated with changes in a variety of other factors. When changes in variables measuring two factors are strongly related statistically and there is a logical, conceptual cause and effect relationship, then it is reasonable to conclude that one factor is the cause of the other. On the other hand, if the changes in different variables are not strongly related statistically or the conceptual basis for a cause and effection relationship is unclear, then less confidence is warranted that the factors are causally related.

On July 15, 1985, the U.S. General Accounting Office (GAO) released a report entitled "Early Assessment of Interior's Area-Wide Program For Leasing Offshore Lands." As part of this report, the GAO attempted to use regression analyses to determine whether the number of bids received for offshore tracts and their high bids have been affected by areawide leasing. The GAO report



concluded that the number of bids per tract decreased by approximately 0.5 bids and the high bid per tract decreased by $3.1 million for "areawide" lease sales held during 1983 and 1984. This GAO estimated decline accounts for $541 of the total $2,624 per acre decline which the GAO found in the average high bids between the tract selection lease sales in the 1979-1983 period and the areawide sales in 1983 and 1984. On this basis, the GAO estimated that the Treasury received $5.4 billion less in bonuses (present value discounted to 1984) than it would have received had the same tracts been leased more slowly. However, the discounting technique used by the GAO was improper and the $5.4 billion figure should actually have been only about $3.7 billion, according to Department of Energy calculations.

The GAO's regression analyses attempt to determine the effect of "areawide" leasing upon average high bid and number of bids per tract after adjusting for certain other factors which the GAO assumed were important in explaining the level of high bids and number of bids received per tract. The GAO assumed that variations in the level of the high bid for a given tract could be caused by the number of bids the tract received, the Government estimated value of the tract at or above the legal minimum bid level assigned by the Government, the price of foreign crude oil, the bidding system used (fixed royalty, sliding scale royalty, or fixed net profit share), the type of tract (wildcat, proven, drainage, or development), the percent of joint bids received on the tract, the location of the sale, the interest rate on triple-A bonds, and annual "dummy variables" (variables which take on the value of "one" if the event occurs and "zero" otherwise) for the years 1980 through 1984. The GAO uses the same variables to analyze variations in the number of bids which a given tract receives.

The GAO's statistical equations using these variables account for less than 25 percent of the observed variation in the number of bids received per tract and only about 35 percent of the observed variation in the high bid received per tract. Thus, GAO's analyses (including their assumption that "areawide" leasing effects the number of bids received and the level of the high bid) explain only a minor portion of the causes of declines in the number of bids and the level of the high bid per tract which have occurred since 1980.

In letters of August 27, 1985, to Congressman Dingell and September 30, 1985, to Congressman Jack Brooks, et. al., the Minerals Management Service (MMS) detailed a variety of deficiencies in the GAO's analyses. These deficiencies can be classified as general theoretical and modeling problems and data problems. The sum total of these deficiencies leads to the conclusion that GAO's findings with respect to areawide leasing are incorrect and misleading.

It is useful to examine the issues raised in the GAO report from a broad perspective to assess the degree of confidence merited by the GAO model. It is clear that bonus bids per acre have declined. As Figure 4 shows, that decline began in 1980, well before the implementation of an areawide leasing approach. Contributing to that decline were reductions in oil company projections of both short- and long-term energy prices; increases in exploration, development and production cost expectations as tracts have been leased in deeper waters, farther from shore, or in more hostile operating conditions; and the decline in geologic prospectiveness of tracts as better prospects become leased and those remaining are smaller, more subtle and more risky. How companies view these changes (and each clearly views them differently) is not really known by the Government or by the GAO. The range of estimates of these variables is likely to be so large as to swamp a refined analysis attempting to quantify relationships to the bids submitted, even if done correctly.

The problems confronted in performing statistical analysis with highly uncertain data are illustrated by the GAO's reliance upon tract value estimates made by the MMS for bid acceptance reviews. These estimates are made by MMS professionals using a substantial amount of professional judgment about a wide variety of economic and geologic factors including those mentioned above. The price expectation assumptions in Table 11 show that the MMS professionals over the past several years systematically overestimated future prices compared to what they would project today. If many companies, when they were bidding, had lower price expectations than did the MMS, that one factor alone would change the results of GAO's entire analysis. Similarly, it has been suggested that industry may have been too optimistic in its assessment of geological potential in the 1979-82 period and thus may have overbid during that period. That optimism has been brought down to earth by the long string of exploration failures offshore the Atlantic and Alaska coasts. In general, it is difficult to make sweeping judgments about the causes of changes in bonus levels, and one should not ascribe too much confidence to attempts at precision when the basic data is subject to great variation and error which has not been measured.

General theoretical and modeling problems present in the GAO's analyses include the failure to develop an explicit theoretical framework for the issue it seeks to analyze, the failure to recognize the highly nonlinear relationship between the real high bid and the number of bids received, and the inclusion of "dummy variables" which mask and confound the determination of individual relationships.

The lack of a theoretical framework leads to the specification of regression equations which do not consistently reflect the many factors that can affect bonus levels. For example in the GAO analysis, variables are included in the regression model to indicate whether sliding scale or fixed net profit share bidding systems were used rather than a fixed royalty bidding system. The use of these alternative systems yields different outcomes regarding the distribution of economic rents paid to the Government in the form of cash bonus and contingency payments and therefore may be expected to affect the level of the high bid and/or the number bids received. Although the different royalty rates used on leases issued under the fixed royalty system also affect the distribution of economic rents to the Government in the same way, the effects of these different royalty rates are not reflected in the GAO analysis. Additionally, the impact of the sixfold increase in the minimum bid level for Sale 71 in 1982 and subsequent sales (from \$25 to \$150 per acre) is not accounted for in the GAO's model. Omission of variables which sound theory would indicate should have been included in the GAO's model may have lead to biased estimates of the effects of areawide leasing.

The regression analyses presented in the GAO report assume that the high bid and the number of bids are linearly related. It is well known from bidding theory, however, that the relationship between the high bid and the number of bidders is highly nonlinear. Failure to recognize this theoretical constraint would cause an overestimate of the impact of changes in leasing rate upon bonus bid levels.



The GAO report[1] implies that GAO views the bidding process as occuring in separate steps. In particular, GAO apparently assumes that a firm will take the expected level of competition into account when formulating its bid amount, but that the magnitude of this bid amount will not effect the decision to participate. This apparently has led the GAO to develop a regression analysis in which the magnitude of the high bid has no effect upon the number of bidders. The GAO proceeded to estimate these relationships using a technique known as ordinary least squares (OLS). If the GAO's assumption that the level of the high bid does not affect the number of bids is correct and if the GAO's analysis did not omit variables from their model which significantly affect both the level of the high bid and the number of bids received per tract, then an OLS approach would be warranted. There is a good reason to believe, however, that the results of the lease auction process do not fulfill either condition.

First, as mentioned previously, the GAO's lack of a theoretical development has apparently led to the exclusion of relevant variables from the GAO's regression equations. Second, some portions of bidding theory imply that the number of bidders depends, in part, upon the perceived value of a tract while the level of the high bid also depends upon the number of bids. These theories state that the observed results of an auction are determined, at least in part, by the entry of more bidders up to the point at which the average profit expected by a bidder declines to a level that is insufficient to attract additional bids.[2] If this holds for OCS bidding, then the results of GAO's analyses based on the assumption that the number of bids does not depend on the value of the tract would be biased. The presentation of additional results in the GAO report[3] which purportedly take into account the two-way interaction between the level of high bid and the number of bids indicates that the GAO may have been aware of the expected bias in their OLS results. Unfortunately, these results have no meaning due to an apparent misapplication of the analytical technique used (known as "two stage least squares"). In particular, the problem is known in econometric theory as that of underidentification, i.e., the observations do not permit the measurement of the relationships that are assumed because the relationships do not include factors unique to the individual relationship.[4] Since the equations are underidentified, the estimates are invalid.

[1]GAO, Early Assessment of Interior's Area-Wide Program For Leasing Offshore Lands, July 15, 1985, Table 3, p.60.

[2]See for instance, Gaskins, D. W., Jr., and Teisberg, Thomas J. 1976. "An Economic Analysis of Pre-Sale Exploration in Oil and Gas Lease Sales." In Essays on Industrial Organization in Honor of Joe S. Bain, edited by Robert T. Masson and P. David Qualls, pp. 241-258. Cambridge, Mass.: Ballinger Publishing Co.

[3]GAO, Early Assessment of Interior's Area-Wide Program For Leasing Offshore Lands, July 15, 1985, Table 4, p. 61.

[4]For a basic introduction to the topic of identification, see for example, Walters, A.A., An Introduction to Econometrics. New York: W.W. Norton & Company, Inc.

A further problem in GAO's model results from the wholesale inclusion of "dummy variables" (those which take on the value of "zero" if a given condition is not present and a value of "one" if the condition is present) without theoretical justification. Inclusion of such variables can mask and confound the determination of individual relationships. This is especially evident in the relationships between the "Area-Wide" dummy variable and the annual dummy variables for the years 1980-1984. The reasons for including annual dummy variables is not clear. Apparently, GAO attempted to account for general macroeconomic changes that may have occurred year to year. If this is in fact the reason, the objective could have been handled directly by including such variables as Gross National Product or Gross Domestic Investment, future price expectations, or other indicators of the economic conditions which theory showed to affect competition or bid levels. However, with dummy variables included instead, the mathematics of the model allow for a variety of valid interpretations of these annual dummy variables. For example, the coefficient of the annual dummy variable for 1984 can just as appropriately be interpreted as measuring the marginal effect of 1984 areawide lease sales. The GAO report's conclusions are extremely sensitive to the specification of these annual dummy variables.

The confounding effect of wholesale inclusion of dummy variables is easily shown. The results of the statistical analyses reported for GAO's base case indicate, other things being equal, that the areawide sales in 1984 received an average of about 1.45 (1.97 - 0.52) more bids per tract than did the tract selection sales in 1979. In fact, the conclusion to be drawn is that only two small tract selection sales in Alaska, held in 1983, received more bids per tract on average, after adjusting for other factors, than did the areawide sales of 1983 and 1984. GAO, however, chooses to look only at the coefficient of the "Area-Wide" dummy variable and concludes that the number of bids has fallen.

There are two classes of conclusions to be found in the GAO report. The first class is based upon equations in which the GAO included the year in which the sales were held as a "dummy" variable in their statistical analyses (the base case and specifications 1, 2, 4, and 6). From this class, the GAO concluded that areawide sales reduced competition. However, these equations equally support the conclusion that sales in 1983 and 1984, the only years in which areawide lease sales were held, had more bids per tract and generally higher bonuses per acre, after adjusting for the other factors in their analysis. The GAO fails to provide either a theoretical framework or a rationale to explain or justify such a large divergence in possible conclusions.

The second class of conclusions is based on those equations in which the GAO did not include the year of the sale as a "dummy" variable (specifications 3 and 5). These equations show no statistically significant relationship between areawide leasing and the level of bonus bids or the number of bids received and, therefore, indicate that there was no bonus loss.

The second general category of deficiencies regarding the GAO regression analyses is data problems. These include the use of data from a censored sample of tracts, errors in variables, and the improper systematic exclusion or inclusion of data. For example, bidding data on all wildcat and proven tracts which receive three or more valid bids and on tracts determined to be nonviable were excluded from GAO's data set. In addition, the GAO included other data which properly should be excluded such as data for tracts with high bids that were rejected. These data problems would be expected to produce a major bias in the analytical results.



The censored sample problem arises because high bids are observed only for tracts receiving bids. Although this fact is obvious, it is not a trivial problem. The set of tracts for which the high bid and the number of bids is recorded is the result of a sample selection rule which leads to biased estimates if not corrected. In a censored sample, the adjustment requires including an additional variable for the conditional probability of observing the data given the selection rule for submitting bids. GAO did not attempt this correction.

The errors in variables problem can be illustrated in relation to the estimates of tract values which are made by the MMS. The data used by the GAO truncates tract values (at the minimum bid level of either $25 or $150 per acre), but nevertheless uses it as a proxy for the value of the tract as perceived by the high bidder. Presumably, the untruncated estimate of tract value generated by the MMS is a random draw from the same distribution as that of the firm. The untruncated estimate of tract value generated by MMS is often a negative value, which is inconsistent with observed bids. Under these circumstances it is not clear that the truncated MMS estimates of tract values are a consistent proxy for the firms' tract values. If the errors in variables problem is not corrected, the GAO's OLS estimates will not only be biased but will also be inconsistent.

The final data problem to be discussed deals with the systematic exclusion from the GAO analyses of data which should be included. Tract value data for nonviable tracts and proven and wildcat tracts receiving three or more adjusted bids in areawide sales are not available for inclusion in GAO's analyses. This is a problem which can lead to extremely biased statistical estimates especially when the form of the equation is misspecified. As shown in the previous section, the value of the high bid is a nonlinear relationship. The omission of proven and wildcat tracts receiving three or more adjusted bids from the analyses would be expected to yield estimates that overstate the impact of the areawide leasing on the number of bids. Similarly, by systematically omitting nonviable tracts (those judged by MMS to have a very low value, if any) the GAO analysis further biases the estimates since more of these nonviable tracts were bid upon under the areawide system than in tract selection sales. As part of MMS's review of the GAO's analyses, the MMS has estimated that certain corrections for the problems associated with missing data for proven and wildcat tracts receiving three or more adjusted bids and nonviable tracts can reduce the magnitude of the "effect of areawide leasing" on the number of bids by 80 percent and render this "effect" statistically nonsignificant.

The GAO's analyses also include observations for several hundreds of tracts whose high bids were rejected. Since GAO uses the results of its analyses to measure "bonus reduction" if any, due to the actual leasing of tracts under the areawide program, it is inappropriate to include in their analyses tracts which were not leased.

The conclusion from this review of GAO's analysis and from independent efforts to perform statistical analysis of areawide leasing is that conventional regression techniques, given the available data, yield little or no convincing evidence that the implementation of areawide leasing was a substantial cause of the observed decline in competition and bonus levels.

# APPENDIX Q

# POSTLEASE PROCESS, REGULATORY PROGRAM AND PERFORMANCE RECORD

# POSTLEASE PROCESS, REGULATORY PROGRAM, AND PERFORMANCE RECORD

## CONTENTS



## ILLUSTRATIONS



## TABLES





## I. INTRODUCTION

This appendix presents a normal course of action which a lessee would take after acquiring an Outer Continental Shelf (OCS) lease, assuming that hydrocarbons are discovered and produced. The steps from preliminary activities through exploration, development, and production to lease relinquishment are identified and described in terms of the regulatory requirements governing them. The inspection and enforcement program also is discussed, and the performance record of postlease operations is examined by identifying significant mishaps, i.e., blowouts and oil spills, which have occurred under the established regulatory program.

A brief explanation of the regulatory framework is necessary before discussing the postlease process. Broad authority pertaining to oil and gas leasing and development is set forth in the OCS Lands Act, as amended. Regulations promulgated under the OCS Lands Act which pertain to postlease operations are at Title 30, Part 250 and Part 256, Subpart N of the Code of Federal Regulations (CFR). The requirements set forth in the law and regulations are defined more specifically by OCS Orders, which provide detailed guidance pertaining to particular activities and operations. Regulatory requirements may also be set forth in lease instruments and stipulations.

Several other laws apply to the postlease process, including: The National Environmental Policy Act, as amended; Coastal Zone Management Act of 1972, as amended; Federal Water Pollution Control Act Amendments of 1972; Rivers and Harbors Act of 1899; Ports and Waterways Safety Act, as amended; Endangered Species Act; Fish and Wildlife Coordination Act; Marine Mammal Protection Act of 1972; Historic Preservation Act of 1966, as amended; and Archeological and Historic Preservation Act of 1974. The Minerals Management Service (MMS) consults and coordinates with the bureaus and agencies which are primarily responsible for implementing the pertinent provisions of these laws. In many cases, Memoranda of Understanding and Agreement have been drafted to clarify responsibilities and facilitate their execution.

## II. POSTLEASE PROCESS AND REGULATORY PROGRAM

### A. Preliminary Activities

Oil and gas activities on a lease begin with the lessee's acquisition of the information necessary to compile a comprehensive exploration plan. These "preliminary activities," prescribed by the MMS at 30 CFR 250.34-1, are operations which entail no more than very shallow penetration of the seabed and which do not affect significantly the natural resources of the Outer Continental Shelf (OCS). No other activities may be conducted on the lease until an exploration plan is submitted by the lessee and approved by the MMS.

The above cited regulation requires the lessee to include in the exploration plan certain standard descriptive information pertaining directly to operations as well as other relevant information. The collection of this other relevant information is accomplished by conducting preliminary activities. The type and extent of relevant information that may be required depends on the characteristics of the specific lease area. Special aspects of the proposed drilling site such as geology, hazardous conditions, ecology, oceanography and meteorology, cultural resource potential, and multiple-use of the area might have to be addressed.

The requirement to address one or more of these lease characteristics may be set forth by the MMS at the prelease stage by attaching a stipulation to the lease or it may come about as a result of postlease review conducted by the MMS office overseeing the lease. The need to consider a specific issue also could arise from a biological opinion issued as a consequence of required consultation on lease sales with the Fish and Wildlife Service or National Marine Fisheries Service pursuant to the Endangered Species Act. Such an opinion may require that certain actions be taken or prevented and certain information be collected so as to avoid jeopardizing species identified as threatened or endangered.

Guidelines developed by the MMS office overseeing the lease, usually issued in a Notice to Lessees and Operators, detail the manner in which this required information is to be collected and the format in which it is to be submitted to the MMS for review. For example, such guidelines might specify the type of geophysical instrumentation to be employed in conducting a required shallow hazards survey, the navigation system to be used while collecting the data, and the type of processing which the collected data are to undergo before they are submitted. The issuance of such guidelines serves to clarify the requirements set forth in rules, lease stipulations, and biological opinions, so that lessees operating in a particular region will know exactly how to conduct preliminary activities and collect the information necessary to compile a comprehensive exploration plan.

B. Exploration Plan and Related Information

1. Contents

After completing preliminary activities, the lessee submits to the MMS an exploration plan which describes the proposed drilling site(s) and the planned exploratory operations. The plan may apply to one or more leases held by the lessee or to a group of unitized leases.* The following components comprise the package of information which the lessee is required to submit:

° Exploration Plan

The regulation at 30 CFR 250.34-1 requires the exploration plan to describe: the proposed type and sequence of exploration activities and a timetable for their execution; the proposed drilling unit; the geophysical equipment to be used; the location of each proposed well; and the structure and formations expected to be drilled. Additional information may be required by each Region's OCS orders.

* Unitization entails combining two or more leases in a joint effort to explore, develop, or produce the unitized area more efficiently. The ultimate purposes served by unitization are prevention of waste, conservation of natural resources, and protection of correlative rights to production.



° Oil Spill Contingency Plan

OCS Order No. 7 requires submission of this plan.* It includes: provisions to assure that full resource capability can be committed to contain and clean up a spill; provisions for varying degrees of response depending on spill severity; provisions for protecting areas of special biological sensitivity; procedures for timely notification of all principals involved in oil spill containment and clean up; and provisions for special actions to be taken after discovery and notification of an oil spill.

° Critical Operations and Curtailment Plan

OCS Order No. 2 requires that this plan be submitted with the exploration plan. It identifies the operations to be conducted on the lease which are considered critical with respect to well control, fire prevention, and prevention of oil spills and other discharges and emissions. The plan also describes the circumstances or conditions under which such critical operations shall be curtailed. For example, a critical operation such as drill stem testing would be identified as impermissible when a certain limit of vessel motion is exceeded due to rough sea conditions.

° Hydrogen Sulfide Contingency Plan

This plan is submitted in accordance with OCS Order No. 2 when proposed drilling operations are expected to penetrate formations which are not known to be free of the poisonous gas hydrogen sulfide. It details specific plans for maintaining safety if hydrogen sulfide is encountered. MMS Standard OCS 1 governs operations conducted in a hydrogen sulfide environment and provides lessees guidance in preparing contingency plans for such operations.

° Environmental Report**

The environmental report is submitted in accordance with 30 CFR 250.34-3. It is not considered a part of the exploration plan, but accompanies the plan throughout the review process. It is a summary of environmental information which cites any pertinent newly developed site specific data not covered in the exploration plan or prelease environmental impact statement. The environmental report includes information on the exploration proposal which pertains to: personnel, supply and service needs and their impacts on the local community; air and sea travel between onshore and offshore facilities; solid and liquid discharges and air emissions; environmentally sensitive or potentially hazardous areas; and anticipated effects on the environment.

* In the Central and Western Gulf of Mexico OCS planning areas and in the Channel Islands area off California, exploration plans may incorporate a previously submitted Oil Spill Contingency Plan.

** Not required for leases in the Central and Western Gulf of Mexico OCS planning areas.

° Certification of Consistency with Coastal Zone Management Program(s) of Affected State(s)

In accordance with 30 CFR 250.34 and 15 CFR 930, a consistency certification must be submitted for each affected State having an approved management program pursuant to the Coastal Zone Management Act, as amended. The lessee identifies all activities described in its exploration plan which are subject to review by each State's management program. The lessee then certifies with a direct statement that these activities are consistent with provisions of the management plans of all affected States.

2. Review and Approval (see Figure 1)

a. Completeness Review and Distribution

The first step in MMS' analysis of the exploration plan is a completeness review to determine that all of the required information described above is included. Once it is deemed complete, the MMS distributes the exploration plan (excluding proprietary information) to affected States and to Federal Agencies such as the Environmental Protection Agency, Department of Defense, Fish and Wildlife Service, National Marine Fisheries Service, Army Corps of Engineers, Coast Guard, and Office of Coastal Resource Management. Copies also are made available to the public.

b. Technical Review

The exploration plan undergoes a thorough technical analysis by MMS engineers and scientists. Much of this review addresses the equipment planned for use in the exploratory drilling operations. The fitness of the drilling facility to perform the proposed operations is examined* with a focus on the rated capacities of all drilling equipment, safety systems, firefighting equipment and pollution prevention equipment. Proposed new or unusual technology receives special scrutiny, and all equipment is evaluated in light of the best available and safest technologies standard mandated by section 21 of the OCS Lands Act, as amended.

Geological and geophysical aspects of the plan also are analyzed. This analysis concentrates on types of geophysical equipment to be used, the well-logging program, proposed well locations, potential geohazards, and cross sections of marker formations.

The oil spill contingency plan, hydrogen sulfide contingency plan, and critical operations curtailment plan are reviewed for adequacy in light of the applicable OCS Orders. The U.S. Coast Guard also conducts a technical review of oil spill response and cleanup equipment procedures in accordance with a Memorandum of Understanding executed in 1981.

* Bottom founded drilling facilities such as artificial islands used for exploratory drilling in the Alaska OCS Region are subject to review under the Platform Verification Program described on page Q-16.



c. Environmental Review

The regulations at 30 CFR 250.34-4 outline the MMS' duty to comply with the National Environmental Policy Act (NEPA) by conducting an environmental review of the proposed operations. Environmental scientists conduct this review, drawing on the information in the environmental report and other documents, comments prepared by staff as a result of their technical review, and the comments of affected States, Federal Agencies, and other interested parties. This review gives particular attention to: facilities proposed for installation in areas of high seismicity; facilities proposed for installation within areas of high ecological sensitivity; the use of bottom founded facilities in areas of potentially hazardous bottom conditions; and the use of new or unusual technology. For an exploration plan in the Alaska Region, the environmental review includes an evaluation of effects on subsistence uses that could occur from exploration, as required by court cases interpreting section 810 of the Alaska National Interest Lands Conservation Act (ANILCA).

Environmental review of the exploration plan results in a finding of no significant impact or a finding that approval of the proposed operations constitutes a major Federal action significantly affecting the quality of the human environment. A finding of no significant impact may be documented by a categorical exclusion review or an environmental assessment. The former procedure examines the exploration proposal in light of an established category of actions which do not have a significant effect on the human environment and for which neither an environmental assessment nor environmental impact statement is required. An environmental assessment briefly discusses the exploration proposal in terms of environmental effects and provides the basis for determining whether to prepare a finding of no significant impact or an environmental impact statement. If it is concluded that approval of the exploration plan is a major Federal action significantly affecting the quality of the human environment, an environmental impact statement will be prepared.

d. Coastal Zone Management Consistency Review

Each affected State having an approved Coastal Zone Management Program is given a maximum of 180 days to review the exploration plan for consistency with its program. Within 90 days after receipt of the plan by the State agency administering the management program, written concurrence or objection to the proposed operations (or a status of review and basis for further delay) is submitted to the MMS by the State agency. The State agency's concurrence with the consistency certification is conclusively presumed in the absence of any written communication to the MMS by that agency.

e. Approval or Disapproval

Within 30 days after the exploration plan has been deemed complete, the MMS must approve it, require modification of it, or disapprove it. The plan is approved if it conforms to the provisions of the lease, the OCS Lands Act, and the regulations. Modification of the plan is required if it does not conform to these provisions. The plan is disapproved if it is decided that the proposed operations probably would cause serious harm or damage to life (including fish and other aquatic life), property, any mineral (in areas leased or not leased), the national security or defense, or to the marine, coastal, or human environment.

Once the MMS approves the exploration plan, consistency concurrence must be received from all affected States before operations proposed in the plan may be permitted. If an affected State rules that the plan is not consistent with its Coastal Zone Management Program, the lessee may appeal to the Secretary of Commerce, who may uphold or reverse the State's findings in accordance with the provisions of 15 CFR 930.

C. Application for Permit to Drill (APD)

1. Contents

The lessee must submit and receive approval of an APD before commencing exploratory drilling operations. It must conform to the regulatory requirements of 250.36 and the more specific requirements of OCS Order No 2. Information required in the APD includes:

- Exact surface and bottom hole location of the proposed well(s), elevation of the derrick floor, and water depth;
- Projected depth of the well(s) and estimated depths at which encounters with water, oil, gas, and mineral deposits are expected;
- Proposed casing and cementing program, including size, weight, grade and setting depths of casing and the amount of cement to be used; and discussion of formation fracture gradients, formation pressures, and anticipated surface pressures;
- Description of the blowout-prevention equipment, including pressure ratings;
- Description of the drilling mud program, including table of well depth versus minimum quantities of mud material to be on hand to assure well control; and
- Logging and coring program.

2. Review and Approval (see Figure 1)

The APD is reviewed by the MMS office charged with overseeing the lease. All of the information listed above is analyzed by engineers and scientists to establish the safety and environmental soundness of the proposed drilling program and to ensure that it conforms to the approved exploration plan.



EXPLORATION PLAN REVIEW

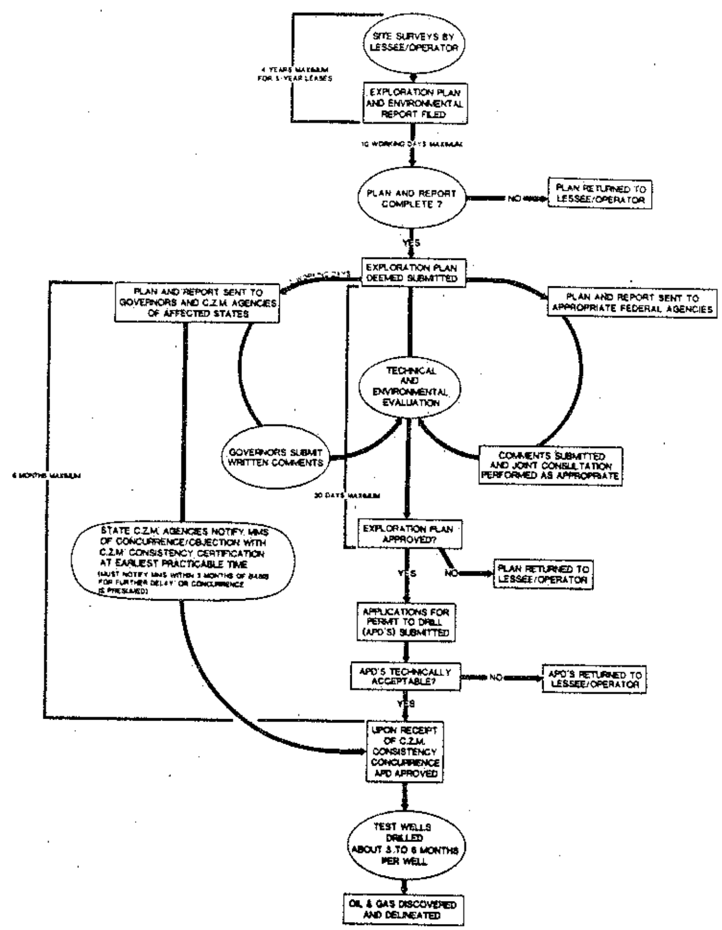



FIGURE 1

Structure maps and cross sections are analyzed for accuracy, and if correlating well logs are available, they are reviewed to glean lithologies and formation pressures that may affect well control. The casing and cementing program is examined to verify conformance with the requirements of OCS Order No. 2, which are designed to maintain safe well conditions and protection of the environment, including freshwater aquifers. Formation fracture gradients, formation pressures, and anticipated surface pressures are scrutinized in light of planned casing setting depths, mud weights, and blowout-prevention equipment, respectively. The mud inventory is checked to verify that sufficient quantities to maintain well control will be readily available. The Welding, Burning and Hot Tapping Plan is reviewed to assure that safe and environmentally sound procedures guiding these activities will be established and followed at the drilling location. Descriptions of well control and pollution-prevention equipment also are examined, as is other required information, including that addressing regional or lease specific criteria.

Based upon this review, the APD is either approved or returned to the lessee for modification. When it is approved, conditions of approval are attached which provide specific directions pertaining to the proposed well(s). These conditions are founded on the regulations and OCS Orders, and do not add regulatory requirements.

As previously stated, the APD may not be approved until all affected States concur (or are conclusively presumed to have concurred) with the lessee's certification of consistency with approved Coastal Zone Management Programs. The approved APD and other Federal permits are required before actual drilling may commence. Other permits include: Coast Guard aids to navigation and certification of mobile offshore drilling unit; Corps of Engineers navigation permit; and Environmental Protection Agency permit for discharging in accordance with the National Pollutant Discharge Elimination System.

## D. Exploratory Operations

### 1. Drilling

Once all necessary permits have been obtained, the lessee will place a drilling facility on the leasehold to commence operations. This facility will undergo a thorough inspection by the MMS prior to being put into operation if it is a new facility or if it has not been used previously in the same OCS region. The type of facility (mobile offshore drilling unit, platform, artificial island) is chosen based on consideration of conditions at the wellsite such as water depth, bottom conditions, and oceanographic and meteorological phenomena.

The exploration project is serviced by an onshore base from which supplies and personnel are sent to the wellsite. Supplies such as drilling mud and equipment usually are sent by boat. Personnel and delicate equipment usually travel by helicopter to the drilling location, which in most cases is equipped with landing and refueling facilities. MMS personnel also fly to the wellsite to perform required periodic inspections of the operations.



Drilling operations are governed by 30 CFR 250 and OCS Order No. 2. The lessee's exploration plan and application for permit to drill and conditions of approval provide additional guidance. These rules and conditions require the following:

- Installation and periodic testing of pollution-prevention equipment;
- Directional surveying at certain depths to record data used to determine the horizontal variation in the location of the wellbore;
- Meeting prescribed casing standards; placing, cementing, and testing casing prior to drilling below specified depths;
- Maintaining proper mud condition to assure well control;
- Training and qualification of drilling personnel;
- Keeping continuous supervision and surveillance of the drilling rig with qualified personnel; and
- Performing specified operations in accordance with the Critical Operations and Curtailment Plan.

The objective of exploratory drilling is to collect information which indicates the potential of the drilled structure to produce hydrocarbons in paying quantities. Well cuttings churned up by the drill bit and carried to the surface by drilling mud are a source of useful information. Sophisticated information is obtained by running logging instruments down the well, and coring is done to acquire large pieces of penetrated formations. All of this information is analyzed to ascertain formation character in terms of paleontology, stratigraphy, permeability, and porosity, which are key indicators in the search for hydrocarbons. When the presence of oil or gas is indicated, the lessee usually performs tests which measure flowing pressure and determine fluid content.

The MMS monitors exploratory drilling operations to ensure that the lessee conforms to laws, regulations, and provisions of the lease and operates in a manner consistent with its approved exploration plan and drilling permit. The drilling unit is periodically inspected, drilling reports are required to be submitted periodically, and certain operations (identified at 30 CFR 250.92) may not be performed by the lessee without written approval of a well Sundry Notice. Also, the MMS has access to all information acquired by the lessee and may conduct its own analysis of the well.

### 2. Plugging and Abandonment

After exploratory drilling is finished, the lessee plugs and abandons the well in accordance with 30 CFR 250.44 and OCS Order No.3. The MMS must approve proposed abandonment operations before they are undertaken, and the lessee is required to file a subsequent report of completed work in a Sundry Notice. MMS inspectors witness abandonment operations when their schedules permit.

Cement plugs must be placed in the well and tested so that fluids cannot move to the surface or migrate between subsurface formations. The intervals between these plugs are filled with mud dense enough to offset formation pressures. Also, drilling equipment and paraphernalia must be removed from the seafloor, and the lessee documents site clearance to the MMS.

3. Determination of Well Producibility and Suspension of Operations

The lessee is required by OCS Order No. 4 to submit to the MMS an application for determination of well producibility within 60 days after abandoning the well and moving the drilling rig off location. This application must be made for every well drilled on a lease until one is determined to be capable of producing oil or gas in paying quantities. The MMS makes this determination for each applicant well based on analysis of well information such as flowtest data, coring reports, and well logs.

If the MMS determines that hydrocarbons in paying quantities have been discovered, the lessee may use this determination as a basis for requesting a suspension of operations on the lease pursuant to 30 CFR 250.12. A suspension of operations is a very useful device for lease development, as it allows the lessee to continue the lease in effect past its primary term while development activities are undertaken and until production commences. A suspension may be granted for up to 5 years to achieve certain purposes, including the following:

- facilitate proper development of the lease; and

- allow for construction of, or negotiation for the use of, transportation facilities.

Suspension requests are most commonly made for these two purposes, and they are considered in light of the provisions of 30 CFR 250.12 (and OCS order No. 14 in the Gulf of Mexico OCS Region). The MMS has established a policy requiring lessees who request such suspensions to submit a schedule of activities reasonably designed to lead to the commencement of production. This schedule and the determination that paying quantities of hydrocarbons exist on the leasehold are necessary for any suspension request to receive serious consideration from the MMS.

4. Delineation of Productive Area

Having drilled one exploratory well on the lease, the lessee's next step depends on the results of that well. All of the information acquired from the well is analyzed, and a decision is made as to whether further drilling on the leasehold is warranted. If the first well failed to encounter oil or gas in paying quantities, the information acquired from the well may indicate that additional evaluation of the lease would



not be worthwhile or it may indicate that the search for hydrocarbons should continue at another site on the leasehold. When producible hydrocarbons are encountered, the lessee usually makes a prompt effort to determine the size and shape of the productive area by drilling additional wells. Each additional well must be described in an approved exploration plan, and drilling operations may not be conducted unless an application for permit to drill the well has been approved.

E. Development and Production Plan

1. Contents

After completing the drilling necessary to delineate the discovered productive area, the lessee is required to submit and receive approval of a development and production plan* before undertaking activities designed to lead to production from the leasehold. This plan is similar to an exploration plan and is subjected to an analogous review process. The development and production plan package to be submitted is composed of several components, which are listed below:

° Development and Production Plan

The regulation at 30 CFR 250.34-2 requires the development and production plan to describe: all the work to be performed to achieve sustained production; all drilling vessels, platforms, pipelines or other facilities and operations; surface and bottom-hole locations of each proposed well; interpretations of all relevant geological and geophysical data; environmental safeguards to be implemented; safety standards and features; the expected rate of development and production; and other relevant information the MMS may require. Additional information may be required by each Region's OCS orders.

The development operations coordination document that may be required in lieu of a development and production plan for leases in the Central and Western Gulf of Mexico planning areas contains only the information listed above which the MMS office overseeing the lease deems necessary to comply with provisions of the lease, laws and regulations. This document is subject to the same review and approval process as a development and production plan.

° Oil Spill Contingency Plan

An oil spill contingency plan similar to that submitted with the exploration plan, but pertaining to the proposed development and production activities, must be submitted prior to or with the development and production plan in accordance with OCS Order No. 7.

* Pursuant to 30 CFR 250.34-2(a)(2), a Development Operations Coordination Document may be submitted in lieu of a development and production plan for leases in the Central and Western Gulf of Mexico OCS planning areas.

- Critical Operations and Curtailment Plan

  A plan similar to that submitted with the exploration plan, but pertaining to the proposed development and production activities, must be submitted in accordance with OCS Order No. 2.

- Hydrogen Sulfide Contingency Plan

  If previous drilling has not proven that the formations to be drilled in developing and producing the discovered reservoir(s) are free of hydrogen sulfide, the lessee must submit a hydrogen sulfide contingency plan addressing the proposed operations in accordance with OCS Order No. 2.

- Environmental Report*

  The environmental report is submitted pursuant to 30 CFR 250.34-3 and contains environmental information not included in the development and production plan. This information includes: the location, description, and size of offshore and onshore operations and facilities; the land, labor, material and energy requirements of the proposed operations; a schedule of near-shore and onshore development activities entailed in the project; a description of environmental monitoring systems; a description of the contingency plans in effect for the activities; and a narrative description of the existing environment.

- Certification of Consistency with Coastal Zone Management Program(s) of Affected States

  The lessee must certify that the activities described in the development and production plan are consistent with provisions of coastal zone management plans of all affected States.

2. Review and Approval (see Figure 2)

   a. Completeness Review and Distribution

      The MMS first conducts a completeness review of the development and production plan and related information. Once deemed complete, a notice announcing receipt of the plan is published in the Federal Register, and copies of the plan (excluding proprietary information) are distributed to appropriate Federal Agencies, affected States, and affected localities for review. Copies also are made available to the public for review and comment.

* Not required for leases in the Central and Western Gulf of Mexico OCS planning areas



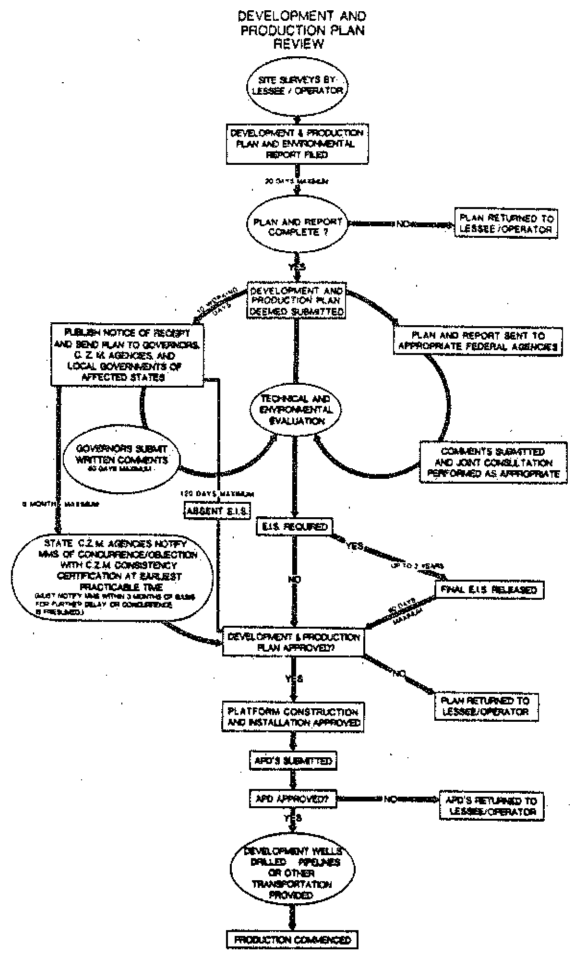



FIGURE 2

b. Technical Review

The development and production plan is analyzed by MMS personnel in a manner similar to exploration plan review. The soundness of technological and scientific information provided in the plan is determined, and intense scrutiny is applied to portions of the plan dealing with proposed safety and pollution-prevention equipment and procedures. The technical review processes for platform and transportation proposals, two major features of development and production activities, are explained separately later in this appendix.

c. Environmental Review

The development and production plan undergoes an environmental review governed by 30 CFR 250.34-4 which is similar to the one conducted for an exploration plan. This review also results in a finding of no significant impact or a finding of significant impact. When environmental analysis determines that permitting the proposed project would be a major Federal action significantly affecting the human environment which has not been considered adequately in a previous environmental impact statement, a new statement pertaining to the project must be prepared. Outside the Central and Western Gulf of Mexico OCS planning areas, approval of a development and production plan must be declared a major Federal action at least once.

An environmental review of proposed development and production operations includes an examination of the planned construction of new onshore facilities which could have significant adverse effects on the environment. It also gives special attention to the cumulative, previously unforeseen, and significantly different impacts which could result from the project. For a development and production plan in the Alaska Region, the environmental review evaluates the effects of proposed activities on subsistence uses, as required by court cases interpreting section 810 of ANILCA.

d. Coordination and Consultation with Affected Sates and Local Governments.

Section 19 of the OCS Lands Act provides for the Governor of any affected State and the executive of any affected local government to be given the opportunity to make recommendations regarding the development and production plan. Recommendations offered during this consultation process are accepted if they are determined to provide for a reasonable balance between the national interest and the well-being of the citizens of the affected States. Also, cooperative agreements may be formed by the Department of the Interior and affected States to facilitate efficient review and approval of development and production plans. For example, plans submitted for leases in California OCS planning areas may be subjected to a joint environmental analysis by the MMS and the State, generating an environmental impact statement/environmental impact report.



e. Coastal Zone Management Consistency Review

Each affected State having an approved Coastal Zone Management Program reviews the development and production plan for consistency with its program. The procedures governing this review are identical to those governing exploration plan review.

f. Approval or Disapproval

The MMS must approve, disapprove, or require modification of the development and production plan within timeframes set forth at 30 CFR 250.34-2. When an environmental impact statement must be prepared, a decision is required within 60 days after release of the final statement. Otherwise, a decision must be rendered within a maximum of 120 days from the date the plan is received by the Governors of affected States.

The plan is approved if it conforms to applicable laws, regulations, lease provisions, and environmental, safety and health requirements. It is required to be modified if it does not conform to such criteria. The plan is disapproved in the following cases: 1) an affected State finds it inconsistent with its Coastal Zone Management Program and that finding is not reversed or overruled by the Secretary of Commerce; 2) it is found to be a threat to national security or defense; or 3) it describes operations which would probably cause serious harm or damage to life (including fish and other aquatic life), property, or the environment.

All development and production operations to be carried out on the lease must be described in the approved development and production plan. Revisions to the plan may become necessary as the project progresses, and these must be proposed, reviewed, and approved in the same manner as the original plan.

F. Production, Processing, and Transportation Facilities

1. Platforms

The facility planned for use in developing and producing the discovered reservoir(s) is described in the development and production plan. Design and fabrication of a floating facility are reviewed and approved by the Coast Guard, and permitting installation of such a facility is the responsibility of the MMS. The MMS permits design, fabrication and installation of any fixed or bottom founded facility in accordance with OCS Order No. 8, with two separate programs established to guide the process:

° Platform Approval Program

The Platform Approval Program operates only in the Gulf of Mexico OCS planning areas. It applies to facilities of proven conventional design proposed for service in areas with stable bottom conditions and relatively calm waters less than 400 feet deep. This program and its application criteria draw on the long and immensely safe record of platform installation and service in the Gulf of Mexico. Under the program, the lessee submits to the MMS an application certified by a registered professional structural engineer. The application is reviewed by MMS engineers to determine the structural soundness of the project, and approval or disapproval of the application is rendered based on their findings.

° Platform Verification Program

The Platform Verification Program operates in all OCS regions. It applies to all fixed and bottom founded production facilities proposed for use in the Atlantic, Alaska, and Pacific Regions. In the Gulf of Mexico, it applies to all facilities not covered by the Platform Approval Program. Briefly summarized, the program calls for independent technical reviewers approved by the MMS to analyze, design and monitor fabrication and installation of proposed facilities. These reviewers, certified verification agents, are contracted by the lessee to perform necessary analyses and inspections of the project and report their findings to the MMS. The MMS makes approval/disapproval decisions based on these reports and on information gained from actual MMS inspection of the project at the design, fabrication and installation stages.

2. Transportation

The oil and gas to be developed and produced ultimately will be transported to shore for processing and refining in the manner described in the development and production plan. Natural gas is carried to shore by pipeline, and oil may be transported by pipeline or by seagoing vessel. The means of transportation which the lessee decides to use for oil is dictated by economic and environmental considerations. For example, a small reservoir in deep water in a frontier area would probably lead the lessee to consider moving oil by tanker. On the other hand, a large resevoir in a commercially proven area of conventional water depth would induce construction of a pipeline to link to already existing infrastructure. Also, a lease stipulation may require the use of a pipeline as the safest and most environmentally sound means to carry oil from the leasehold.

The U.S. Coast Guard has responsibility for regulating the transportation of crude oil by vessel. All vessels engaged in OCS activities are subject to Coast Guard standards pertaining to: design, loading, fabrication and construction requirements; stability and buoyancy; modification and repair requirements related to structural integrity; and general arrangement. Additional Coast Guard requirements include those for training, drills, inspections, and emergency procedures with respect to transfer of petroleum and other products from or to a vessel. The applicable regulations are set forth in titles 33 and 46 of the CFR.

If the lessee intends to move produced oil and gas to shore with a pipeline, an application for the appropriate permit must be submitted to the MMS. A pipeline which is wholly contained within the boundaries of a single lease, unitized leases, or contiguous (not



cornering) leases held by one owner or operator is permitted under lease terms and in accordance with 30 CFR 250.20 and OCS Order No. 9. Such a pipeline which traverses lease boundaries outside the above described limits or crosses unleased lands is permitted through the issuance of a right-of-way in accordance with 30 CFR 256, Subpart N. The MMS does not have permitting authority for pipelines located in State waters, but does work with the affected State by providing a copy of the pipeline application under MMS consideration.

Overall regulation of pipelines is shared by the Department of the Interior and the Department of Transportation. The MMS, with its permitting program, has established requirements governing pipeline design, fabrication and installation calling for the use of best available and safest technologies as required by section 21 of the OCS Lands Act. The Department of Transportation regulations at 49 CFR 192 and 195 provide detailed safety rules and procedures pertaining to design, construction, operation, maintenance, and testing of pipelines. The division of responsibilities concerning OCS pipelines is spelled out in a Memorandum of Understanding which the Department of the Interior and the Department of Transportation executed in 1976.

The MMS reviews the lessee's pipeline application for consistency with the above referenced rules and lease provisions, including any special lease stipulations. The pipeline must be designed to withstand environmental conditions such as current scour, external corrosion, and ice movement (in the arctic), as well as the internal pressures, temperatures, and corrosive and erosive qualities of the transported fluids. The MMS also ensures that the planned pipeline will not pose an unreasonable obstruction to fishing and shipping operations, administering a policy calling for burial of pipelines in rights-of-way with water depths of less than 200 feet.

6. Development and Production Operations

1. Platform Installation

The platform from which the lessee will drill and produce the discovered hydrocarbons is installed in accordance with OCS Order No. 8. An installation verification plan must be submitted if the platform is covered by the Platform Verification Program. This plan discusses the technical details of the planned installation, names the certified verification agent, and describes the work the agent will do on the project. The platform is required to be installed in a manner consistent with the installation verification plan. If not covered by the Platform Verification Program, platform installation is governed by the Platform Approval Program.

2. Development Drilling

The drilling operations described in the lessee's approved development and production plan must be permitted by an approved Application for Permit to Drill. Also, operations common in development activities, such as deepening, side tracking, or plugging back an existing well, must be similarly permitted.

The content requirements and review procedures described above in Part C of this appendix also apply to an Application for Permit to Drill development wells.

Wells are then drilled to develop the discovered hydrocarbons. These wells usually are drilled directionally from one platform containing several slots arranged in rows to enable drilling operations to hit the various targets identified by the lessee for maximum efficient flow and recovery. Subsea (sea floor) completions may be drilled and completed some distance away from a platform and connected to the platform through flow lines. All drilling operations are governed by 30 CFR 250, OCS Order No. 2, and permit conditions of approval, and they are monitored by MMS personnel.

3. Completion and Production Operations

a. Completion

Once each well is drilled to a productive target, the well is completed to enable actual production of the hydrocarbons. Completion operations entail placing production casing, tubing and packers, and wellhead equipment and perforating the production casing opposite the formation(s) to be produced. The production string of casing seals off the producing formation, the tubing and packers enable the well to flow to surface, and the wellhead seals the well at the surface to allow surface control of flow. Completions are governed by OCS Orders No. 2 and No. 6.

b. Production

(1) Safety Procedures and Equipment

The safety of production operations is guided primarily by OCS Order No. 5, which outlines requirements pertaining to general platform operations and to production safety systems. The latter are designed to prevent significant impacts on safety, health, and the environment from occurring during the course of producing oil and gas. All production safety systems must be installed and operated in accordance with the Order and its call for the use of best available and safest technologies. Production facilities are subject to a preproduction (startup) inspection, and each facility is inspected by the MMS at least once per year thereafter.

(2) Measurement

Since a royalty on produced hydrocarbons is paid to the Federal Government, the lessee is required to measure accurately the volume produced, using equipment and procedures described in OCS Order No. 13. The lessee must submit and receive approval of an application describing the measurement system before actually commencing production. This application is reviewed by MMS staff in light of the requirements of OCS Order No. 13. Once it is



approved and production commences, the MMS periodically verifies the measurement of produced hydrocarbons as part of its field inspection program.

(3) Rate Control

To prevent waste and protect correlative rights to the reservoir, it must be produced at a rate proposed by the lessee and approved by the MMS pursuant to OCS Order No. 11. This maximum efficient rate is specific to each reservoir and is defined as the highest sustainable daily withdrawal rate at which the reservoir can be economically developed and depleted without detriment to ultimate recovery.

A maximum production rate, which applies to individual well completions rather than reservoirs, must be proposed and approved for each oil or gas completion in the reservoir. Establishment of this rate is based on information acquired from well tests. The sum of all maximum production rates for a reservoir may not exceed that reservoir's maximum efficient rate.

c. Servicing and Workover

The producing performance of the reservoir is monitored by periodically conducting flow tests. The results of these tests may indicate that well servicing and workover operations are necessary to restore full production capability. These operations entail repairs to production equipment and materials or alteration of the producing formation. The lessee must receive MMS approval of a detailed Sundry Notice of intent to perform such an operation before commencing it, and a subsequent report of the operation must be filed with the MMS when finished. A Plan for Conducting Simultaneous Operations, submitted and approved in accordance with OCS Order No. 5, governs servicing and workover operations when they are performed concurrently with production operations.

H. Lease Expiration and Abandonment

The lease continues in effect for an established primary term of 5, 8, or 10 years and as long thereafter as oil or gas is produced in paying quantities or approved drilling or well reworking operations are conducted to restore production. After the primary term has expired, a 90-day lapse on such operations in the absence of an approved suspension of operations will cause the lease to expire. When production ceases and further drilling and workover operations are determined to be unwarranted, the following actions become necessary:

1. Borehole Abandonment

The lessee must immediately abandon all boreholes in accordance with 30 CFR 250.44 and OCS Order No. 3. The procedure for abandoning these wells is the same as that described for exploration wells, except that abandonment of a formerly producing well always must be described in advance in a Sundry Notice. This written notification of intent to abandon must state the reason for abandonment as well as present the plan of work to be followed. Actual work may not begin until the Sundry Notice is approved by the MMS.

2. Platform Removal

Pursuant to the lease agreement, the lessee has one year to remove from the leasehold all structures, machinery, and other materials. There is an exception to this provision. If the structures are involved in operations on other leases, they may be left in place as long as they are useful to those operations. Also, an evolving new program may someday allow structures that have established themselves as artificial reefs supporting rich and varied biological resources to be left in place.

When the platform is removed, operations must be conducted in accordance with OCS Order No. 3, which requires the clearance of all piling and other material to a depth of at least 15 feet below the ocean floor. The lessee then must document to the MMS that the leasehold has been abandoned properly and is free of seafloor obstructions.

3. Pipeline Abandonment

If it is determined by the lessee or the holder of the pipeline right-of-way and the MMS that the pipeline will serve no purpose as a result of cessation of production from the leasehold, the right-of-way will be terminated. The pipeline must be properly abandoned, and any pipeline stations and associated equipment which might pose a hazard to navigation must be removed. The pipeline need not be removed but may be abandoned in place provided that such action does not cause unreasonable hazard to navigation, commercial fishing or the marine environment. The line is required to be purged of all petroleum products, and any open ends of the pipe must be plugged and buried to a minimum depth of 3 feet.

## III. INSPECTION AND ENFORCEMENT

### A. Inspection Program

The MMS performs onsite compliance inspections of OCS oil and gas operations in accordance with 30 CFR 250.11. The regulation requires each OCS facility to be inspected at least once a year and also calls for periodic unannounced inspections. Inspection policies and procedures are documented in the MMS Offshore Inspection Program Manual Chapter dated May 8, 1983, and their implementation is directed by the Offshore Inspection Program Handbook dated July 17, 1984. Field office supplements and instructions further define the policies and procedures of the inspection manual chapter.

A national inspection characteristics checklist, the potential incident of noncompliance (PINC) list, is used to carry out each inspection. It consists of regulatory requirements, including all safety and pollution-prevention requirements set forth in the OCS Orders, which are presented in the form of questions calling for yes or no answers. A negative answer to any question indicates an incident of noncompliance (INC), which is a violation of a regulatory requirement.



Drilling and production inspections are categorized as detailed or nondetailed. A detailed inspection is conducted at least annually on each production and drilling facility. In a detailed inspection, the entire PINC list pertaining to the activity (drilling or production) being inspected is used. In a nondetailed inspection, a portion of the applicable PINC list is used. The PINC's used in a nondetailed inspection are selected by reviewing past inspection data. Nondetailed inspections are unannounced, are done randomly in some cases, and are performed on problem facilities more often if warranted.

The frequency at which a facility is inspected depends on several factors. Facilities operating in frontier areas are inspected more frequently than those in mature areas, and a facility with a poor record in past inspections will be inspected more often than one with a good record. The Offshore Inspection System, an automated file of inspection results, provides pertinent data for scheduling inspections. This system is a nationwide data base which is used as a management tool in planning all aspects of inspections.

Inspections are carried out by petroleum engineering technicians who are based at a field office near the area of operations. A PINC list may be specifically developed for each inspection. An INC is issued to the operator for any violation detected, and each one elicits a prescribed enforcement action consisting of the issuance of a warning or a shut-in order. A warning generally is issued for any INC which does not jeopardize safety or have the potential to cause pollution, and the INC must be corrected within a prescribed period of time. A shut-in order is issued for more critical INC's, causing the cessation of a particular operation until the situation responsible for the INC is corrected. The shut-in order may apply to the entire facility or to just a part of the facility.

### B. Penalties

The penalties which may be assessed to persons violating any provision of the OCS Land's Act or pertinent rules, regulations, leases, licenses, or permits are set forth at 30 CFR 250.80-2. Penalties include two types:

° Civil Penalties

Civil penalties may be pursued for cases in which a lessee has violated a requirement and failed to correct the violation after being notified and given a reasonable time to correct it. For example, a lessee failing to correct an INC within the prescribed time would normally be assessed such a penalty. Anyone charged with such a violation is given the opportunity to present evidence at a hearing conducted in accordance with detailed provisions set forth at 30 CFR 250.80-1. If a civil penalty is actually assessed, it is in the form of a fine of up to 10,000 dollars for each day the violation existed.

° Criminal Penalties

Criminal penalties are assessed in cases of knowing and willful violation of certain requirements, most notably those related to safety and environmental protection. Such cases are initially investigated by the MMS and subsequently referred to the Department of Justice for trial in Federal Court. If a criminal penalty is assessed, it consists of a fine of up to 100,000 dollars or a prison term of up to ten years, or both.

## IV. PERFORMANCE RECORD

### A. Data

Tables 1 through 3 express with statistics the record of oil and gas operations on OCS leases. The source of the data in these tables is the computerized events file which the Department of the Interior has maintained since 1971. This file lists operational events including blowouts, spills, and accidents which have occurred on OCS leases and pipeline rights-of-way. The tables which have been compiled for this appendix present information only on blowouts and oil spills as follows:

° Table 1 OCS Oil Spills of 50 or More Barrels

All oil spills of 50 or more barrels which are recorded in the events file are listed. It must be recognized that information is incomplete on those spills which occurred before inception of the events file in 1971.

° Table 2 Recorded OCS Blowouts: 1954-1970

Blowouts recorded in the events file for the period covered from implementation of the OCS Lands Act in 1954 to the year 1970 are listed. Again, this list is incomplete, because no comprehensive file was established prior to 1971.

° Table 3 Recorded OCS Blowouts: 1971-1985

Blowouts recorded from inception of the events file are listed, as well as resulting spill amounts, number of new wells started each year, and total of oil and condensate produced each year.

A blowout is a sudden, often violent, release of hydrocarbons to the environment which is caused by loss of well control. It may cause personal injury or death and extensive property damage, and if crude oil or condensate is involved, an oil spill occurs. For the purposes of the events file and this appendix, an oil spill is considered any unauthorized release of crude oil, condensate or similar liquid hydrocarbon in the course of OCS operations. The source of an oil spill listed in the events file may be a well, pipeline or any vessel or structure directly involved in OCS exploration, development or production.

Blowouts and oil spills are identified in this examination of the OCS record, because they are negative, sometimes catastrophic, events which indicate failure to conduct safe and efficient operations as called for by the regulatory program. The release of hydrocarbons into the ocean may negatively affect the contacted environment and cause losses to other industries such as tourism and fishing. An oil spill which is not contained and reaches shore may cause severe damage to the coastal environment and exact tremendous cleanup expenses. Such losses and expenses, termed social costs, are discussed in depth in Appendix G.



Table 1 OCS OIL SPILLS OF 50 OR MORE BARRELS

| Date | Operation | Region | Event | Pollution | Amount (barrels) |
|---|---|---|---|---|---|
| 01/20/64 | Drilling | GOM | Blowout | Crude Oil | 100 |
| 04/08/64 | Production | GOM | Spill | Crude Oil | 2,559 |
| 10/03/64 | Production (Hurricane) | GOM | Blowout | Crude Oil | 5,180 |
| 10/03/64 | Production (Hurricane) | GOM | Spill | Crude Oil | 5,100 |
| 10/03/64 | Production (Hurricane) | GOM | Spill | Crude Oil | 1,589 |
| 07/19/65 | Drilling | GOM | Blowout | Crude Oil | 1,688 |
| 02/27/67 | Production (Pipeline) | GOM | Spill | Crude Oil | 65 |
| 10/17/67 | Production (Pipeline) | GOM | Spill | Crude Oil | 160,638 |
| 03/12/68 | Production (Pipeline) | GOM | Spill | Crude Oil | 6,000 |
| 01/24/69 | Production (Pipeline) | GOM | Spill | Crude Oil | 100 |
| 01/28/69* | Drilling | PAC | Blowout | Crude Oil | 10,000 (to 79,000) |
| 02/10/69 | Production (Pipeline) | GOM | Spill | Crude Oil | 342 |
| 02/11/69 | Production (Pipeline) | GOM | Spill | Crude Oil | 7,532 |
| 03/16/69 | Drilling | GOM | Blowout | Crude Oil | 2,500 |
| 08/10/69 | Production (Pipeline) | GOM | Spill | Crude Oil | 50 |
| 08/14/69 | Production | GOM | Spill | Condensate | 63 |
| 12/16/69 | Production (Pipeline) | PAC | Spill | Crude Oil | 900 |
| 01/07/70 | Production (Pipeline) | GOM | Spill | Crude Oil | 228 |

* This spill occurred as a result of a blowout in Santa Barbara Channel. The events file reports that oil has continued to seep since the blowout, totaling about 27,000 barrels through 1985. Other sources have estimated the initial volume of this spill to be as high as 79,000 barrels.

| | | | | | |
|---|---|---|---|---|---|
| 02/10/70 | Production | GOM | Spill | Crude Oil | 30,000 |
| 02/28/70 | Production (Pipeline) | GOM | Spill | Crude Oil | 50 |
| 05/28/70 | Production | GOM | Spill | Crude Oil | 100 |
| 05/31/70 | Production (Pipeline) | GOM | Spill | Crude Oil | 50 |
| 10/27/70 | Production (Pipeline) | GOM | Spill | Crude Oil | 395 |
| 12/01/70 | Completion/ Workover | GOM | Blowout | Crude Oil | 53,000 |
| 04/05/71 | Drilling | GOM | Spill | Diesel Fuel | 200 |
| 05/15/71 | Production | GOM | Spill | Crude Oil | 50 |
| 05/26/71 | Production | GOM | Spill | Crude Oil | 75 |
| 05/27/71 | Production | GOM | Spill | Crude Oil | 50 |
| 05/29/71 | Production | GOM | Spill | Crude Oil | 135 |
| 07/20/71 | Production (Storage Barge) | GOM | Spill | Crude Oil | 100 |
| 08/13/71 | Production | GOM | Spill | Crude Oil | 50 |
| 10/16/71 | Production | GOM | Blowout | Crude Oil | 450 |
| 11/14/71 | Production (Pipeline) | GOM | Spill | Crude Oil | 70 |
| 12/09/71 | Production (Pipeline) | GOM | Spill | Crude Oil | 50 |
| 12/18/71 | Production (Pipeline) | GOM | Spill | Crude Oil | 80 |
| 01/07/72 | Production (Pipeline) | GOM | Spill | Crude Oil | 81 |
| 06/13/72 | Production (Pipeline) | GOM | Spill | Crude Oil | 100 |
| 01/09/73 | Production | GOM | Spill | Crude Oil | 9,935 |
| 05/12/73 | Production (Pipeline) | GOM | Spill | Crude Oil | 5,000 |
| 06/20/73 | Drilling | GOM | Spill | Diesel Fuel | 239 |



| | | | | | |
|---|---|---|---|---|---|
| 12/08/73 | Drilling | GOM | Spill | Diesel Fuel | 95 |
| 04/17/74 | Production (Pipeline) | GOM | Spill | Crude Oil | 19,833 |
| 05/21/74 | Production | GOM | Spill | Crude Oil | 65 |
| 7/10/74 | Production | GOM | Spill | Crude Oil | 130 |
| 09/07/74 | Production | GOM | Blowout | Crude Oil | 75 |
| 09/09/74 | Production | GOM | Spill | Crude Oil | 3,500 |
| 10/04/74 | Production | GOM | Spill | Crude Oil | 50 |
| 11/27/74 | Production | GOM | Spill | Crude Oil | 120 |
| 12/22/74 | Well Repair | GOM | Blowout | Crude Oil | 200 |
| 3/18/75 | Production | GOM | Spill | Diesel Fuel | 166 |
| 09/21/75 | Drilling | GOM | Spill | Diesel Fuel | 100 |
| 02/29/76 | Production (Pipeline) | GOM | Spill | Crude Oil | 414 |
| 04/09/76 | Production | GOM | Spill | Crude Oil | 82 |
| 10/19/76 | Production | GOM | Spill | Diesel Fuel | 300 |
| 12/18/76 | Production (Pipeline) | GOM | Spill | Crude Oil | 4,000 |
| 03/29/77 | Production (Pipeline) | GOM | Spill | Crude Oil | 250 |
| 06/05/77 | Production (Pipeline) | GOM | Spill | Crude Oil | 50 |
| 10/18/77 | Production (Pipeline) | GOM | Spill | Crude Oil | 300 |
| 12/14/77 | Drilling | GOM | Spill | Drilling Mud | 70 |
| 04/08/78 | Production (Pipeline) | GOM | Spill | Crude Oil | 135 |
| 05/11/78 | Production | GOM | Spill | Crude Oil | 104 |
| 7/10/78 | Production | GOM | Spill | Crude Oil | 900 |
| 01/30/79 | Drilling | GOM | Spill | Diesel Fuel | 321 |
| 01/31/79 | Production | GOM | Spill | Diesel Fuel | 165 |

| | | | | | |
|---|---|---|---|---|---|
| 04/14/79 | Production | GOM | Spill | Crude Oil | 60 |
| 11/23/79 | Drilling | GOM | Spill | Diesel Fuel | 1,500 |
| 01/23/80 | Production | GOM | Spill | Diesel Fuel | 286 |
| 01/29/80 | Production (Pipeline) | GOM | Spill | Condensate | 100 |
| 05/16/80 | Production | GOM | Spill | Diesel Fuel | 150 |
| 06/11/80 | Drilling | GOM | Spill | Diesel Fuel | 80 |
| 10/15/80 | Drilling | GOM | Spill | Diesel Fuel | 83 |
| 11/13/80 | Production | GOM | Spill | Crude Oil | 1,456 |
| 12/02/80 | Drilling | GOM | Spill | Diesel Fuel | 116 |
| 02/15/81 | Production | GOM | Spill | Crude Oil | 58 |
| 04/06/81 | Drilling | GOM | Spill | Drilling Mud | 126 |
| 08/05/81 | Production | GOM | Spill | Crude Oil | 80 |
| 08/19/81 | Drilling | GOM | Spill | Diesel Fuel | 50 |
| 11/28/81 | Service/ Workover | GOM | Blowout | Crude Oil | 64 |
| 12/11/81 | Production (Pipeline) | GOM | Spill | Crude Oil | 5,100 |
| 01/19/82 | Drilling | GOM | Spill | Diesel Fuel | 200 |
| 04/29/82 | Drilling | GOM | Spill | Diesel Fuel | 228 |
| 08/18/82 | Drilling | GOM | Spill | Diesel Fuel | 214 |
| 01/20/83 | Production (Pipeline) | GOM | Spill | Crude Oil | 80 |
| 01/30/83 | Drilling | GOM | Spill | Oil Base Mud | 800 |
| 02/01/83 | Production (Pipeline) | GOM | Spill | Crude Oil | 125 |
| 03/09/83 | Drilling | GOM | Spill | Diesel Fuel | 100 |
| 03/20/83 | Drilling | GOM | Spill | Diesel Fuel | 320 |
| 04/14/83 | Production | GOM | Spill | Diesel Fuel | 200 |
| 05/09/83 | Drilling | GOM | Spill | Diesel Fuel | 100 |



| | | | | | |
|---|---|---|---|---|---|
| 05/16/83 | Drilling | GOM | Spill | Diesel Fuel | 95 |
| 08/02/83 | Production | GOM | Spill | Diesel Fuel | 119 |
| 06/20/84 | Production | GOM | Spill | Crude Oil | 50 |
| 07/08/84 | Drilling | GOM | Spill | Diesel Fuel | 100 |
| 01/22/85 | Drilling | GOM | Spill | Diesel Fuel | 107 |
| 02/16/85 | Production (Pipeline) | GOM | Spill | Crude Oil | 320 |
| 06/03/85 | Drilling | GOM | Spill | Diesel Fuel | 643 |
| 07/30/85 | Drilling | GOM | Spill | Drilling Mud | 50 |
| 09/02/85 | Production | GOM | Spill | Condensate | 66 |
| 09/26/85 | Drilling | GOM | Spill | Diesel Fuel | 58 |

Table 2 RECORDED OCS BLOWOUTS: 1954 TO 1970

| Year | Drilling Blowouts | Nondrilling Blowouts | Total |
|---|---|---|---|
| 1954 | 0 | 0 | 0 |
| 1955 | 0 | 0 | 0 |
| 1956 | 1 | 0 | 1 |
| 1957 | 1 | 0 | 1 |
| 1958 | 1 | 0 | 1 |
| 1959 | 1 | 0 | 1 |
| 1960 | 1 | 1 | 2 |
| 1961 | 0 | 0 | 0 |
| 1962 | 1 | 0 | 1 |
| 1963 | 1 | 0 | 1 |
| 1964 | 5 | 2 | 7 |
| 1965 | 5 | 0 | 5 |
| 1966 | 2 | 0 | 2 |
| 1967 | 2 | 0 | 2 |
| 1968 | 6 | 1 | 7 |
| 1969 | 1 | 2 | 3 |
| 1970 | 1 | 1 | 2 |
| Total | 29 | 7 | 36 |



Table 3 RECORDED OCS BLOWOUTS: 1971-1985

| | | Production | Drilling Blowouts | | | | Nondrilling Blowouts | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Exploration | | Development | | Production | | Workover | | Completion | | | |
| Year | No. of New Wells Started | Oil and Condensate in Barrels (Millions) | No. | Barrels Spilled | No. | Barrels Spilled | No. | Barrels Spilled | No. | Barrels Spilled | No. | Barrels Spilled | Total No. of OCS Blowouts | Total No. of Barrels Spilled |
| 1971 | 864 | 418.5 | 2 | 0 | 0 | 0 | 2 | 450 | 1 | 0 | 0 | 0 | 5 | 450 |
| 1972 | 856 | 411.9 | 2 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3 | 0 |
| 1973 | 629 | 394.7 | 2 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3 | 0 |
| 1974 | 801 | 360.6 | 0 | 0 | 1 | 0 | 2 | 75 | 1 | 200 | 0 | 0 | 4 | 275 |
| 1975 | 841 | 330.2 | 4 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 1 | 0 | 6 | 0 |
| 1976 | 1,086 | 316.9 | 1 | 0 | 4 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 6 | 0 |
| 1977 | 1,220 | 303.9 | 2 | 0 | 2 | 0 | 0 | 0 | 3 | 0 | 2 | 0 | 9 | 0 |
| 1978 | 1,139 | 292.3 | 4 | 0 | 5 | 0 | 0 | 0 | 2 | 0 | 1 | 0 | 12 | 0 |
| 1979 | 1,109 | 285.6 | 3 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 |
| 1980 | 1,079 | 277.4 | 3 | 0 | 1 | 0 | 1 | 1 | 2 | 0 | 1 | 0 | 8 | 1 |
| 1981 | 1,109 | 289.8 | 2 | 0 | 1 | 0 | 0 | 0 | 2 | 64 | 5 | 0 | 10 | 64 |
| 1982 | 1,159 | 321.2 | 0 | 0 | 4 | 0 | 0 | 0 | 3 | 0 | 1 | 0 | 8 | 0 |
| 1983 | 1,066 | 348.3 | 3 | 0 | 4 | 0 | 0 | 0 | 1 | 0 | 1 | 0 | 9 | 0 |
| 1984 | 1,136 | 370.2 | 3 | 0 | 2 | 10 | 0 | 0 | 1 | 0 | 0 | 0 | 6 | 10 |
| 1985 | 1,040 | 389.3 | 2 | 0 | 0 | 0 | 1 | 40 | 1 | 0 | 0 | 0 | 4 | 40 |
| Total | 15,334 | 5,110.8 | 33 | 0 | 28 | 10 | 7 | 566 | 18 | 264 | 12 | 0 | 98 | 840 |

## B. Conclusion

Tables 1 through 3 and information available from other sources indicate that the overall record of OCS oil and gas operations has been excellent. Table 1 shows that since inception of the events file, the number of 50 barrel or more oil spills per year has averaged 5, and only four spills of over 1000 barrels have occurred during the past ten years. Table 3 indicates that the number of blowouts which occurred between 1971 and 1985 represents sixty-three thousandths of one percent of the total of all new wells started during this time. Only 7 blowouts during the same period resulted in oil spills, and the 840 barrels of oil spilled as a result of these blowouts constitutes an infinitesimal percentage of total produced oil and condensate. Moreover, the National Academy of Sciences' 1985 publication, Oil in the Sea, reports that during the period 1971-1978, the average spillage rate in the Gulf of Mexico OCS was twenty-two thousandths of one percent of the total crude oil produced (2.7 billion barrels).

Since the Santa Barbara Channel blowout in 1969, which resulted in a large oil spill that is the only United States OCS spill ever to contact shore in significant amounts, operating regulations have been strengthened and great technological advances have been made. Overall procedures governing operations, requirements pertaining to blowout preventers and production safety systems, the actual capabilities of such pollution prevention equipment, and the MMS compliance inspection program have promoted extremely safe and environmentally sound operations.

# APPENDIX R

## Estimating Procedures Used for Valuation Analysis

# ESTIMATING PROCEDURES USED FOR VALUATION ANALYSIS

## Introduction

As described in Part III of the SID, the same data developed for the area-by-area net social value estimates were used to value the sales of each program alternative for the valuation analysis. The net social value estimates were derived from the estimates of net economic value (Appendix F) and social costs (Appendix G) for each planning area. However, unlike the net economic value analysis which estimated value from production of all leasable resources if leased in mid-1987, the valuation exercise required that value be estimated from a projection of the amount of resources which would be leased at the time of each lease sale under each program alternative. From this projection, net economic value at the time of sale was estimated and the associated social cost, attributable to production from that sale, was deducted to determine net social value for each sale. These future values were then discounted to present value (i.e., 1987 dollars) to serve as a basis for comparing the estimated net social value of each program alternative.

In order to fully compare the program alternatives, net social value for resources remaining unleased at the end of the 5-year program is also estimated. /1 These estimates are important to consider when comparing program alternatives because those alternatives which are expected to result in the early leasing of most resources will be relatively overstated when examining results for 5-year program leasing only. This is the case because proposals which defer more resources from this 5-year program can have relatively higher values of remaining resources associated with leasing which may occur in later years. /2

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/1 The approach used for estimating value of remaining unleased resources is described in the next section. Note that this approach was modified slightly for analysis of the California proposals.

/2 However, in most cases, given the economic assumptions of the 5-year program, the higher values associated with later leasing of remaining unleased resources will not offset the sizeable economic benefits from earlier leasing. In some of the low price cases, as found in the Appendix F economic analysis, certain low-valued prospects could realize a gain in value from real oil price growth sufficiently large to offset the effects of discounting future production revenue to present value. (See discussion of cost of delay in Appendix F).



## Estimating Resources Expected to be Leased

In order to estimate value for the SID program options, it was necessary that an estimate be made of the amount of resources which are expected to be leased in each sale scheduled under each program alternative considered. Resources expected to be leased differ among proposals to reflect both the differences in timing of leases sales and differences in resource availability (as a result of subarea deferrals) at the time of sale. During the presale process, the Secretary will make a determination as to the specific size of the lease sale. For this analysis, resources expected to be leased from each sale were estimated assuming that OCS acreage will be offered under the "focusing on promising acreage" presale process.

However, it should be noted that the sale size ultimately determined by the presale process will affect the amount of resources which are leased during the 5-year program. The rate of leasing resources which could be expected to be leased under the formerly used tract selection or areawide sale processes will differ from the projections used for the "focusing on promising acreage" process; but, as explained in section III.B., the exact differences are uncertain for many planning areas, and are therefore not assessed on a sale-specific basis for the valuation of the program alternatives. However, in general terms, past leasing experience indicates that the tract selection approach would result in a lower rate of resources being leased during the 5-year program than would be leased under the "focusing on promising acreage" sale process. As a consequence, tract selection sales would result in a lower expectation of net social value. Also, based on past leasing experience, the areawide sale process should be expected, on the whole, to result in a higher rate of resources being leased than under the "focusing on promising acreage" approach. This is the case because "focusing" could preclude the offering of some acreage with hydrocarbon potential that otherwise could be leased. (See Part III.B. for the discussion of size/presale process). Therefore, given the base case economic assumptions, and the resulting cost of delay analysis in Appendix F, areawide leasing would in most cases increase expectations of net social value--assuming that the sales could be held. If, however, "focusing on promising acreage" increased the likelihood that a sale would actually be held--by, for example, reducing the chances of a sale being enjoined as a result of litigation, then "focusing on promising acreage" could produce the actually higher value. This is clearly a matter of judgment for the Secretary.

There is a high degree of professional judgment used to estimate the amounts of undiscovered economically recoverable resources which could be leased in future sales. The sale-by-sale percentages of resources expected to be leased were based on a consideration of past leasing rates, composite industry interest, prospect distribution, infrastructure justification, total leasable resources and sale type. The sale-by-sale projections were based on the risked mean estimates of economically recoverable resources for each planning area. The sale estimates were not varied for different oil price assumptions. /1 In this analysis, where results are displayed for the low and high price cases, the differences in results reflect the differences in net economic value estimates under different starting oil price assumptions (see Appendix F).

The amount of resources projected to be leased in a series of sales within each planning area during the 5-Year Program is based on those resources which are economically recoverable (or "developable"); i.e., resource which are economic to develop, given that they have been discoverd. In some cases, these projections exceeded the amount of resources classified as "leasable" for purposes of calculating net economic value in Appendix F. The projections of resources expected to be leased and the estimates of leasable resources were generated for different purposes and therefore have different meanings. Estimates of "leasable" resources provide a basis for computing the measure of a planning area's net economic value for a given set of economic assumptions at the start of the next 5-year program. This measure allows for a relative ranking of the prospective nature of planning areas.

/1 If actual and expected future oil prices fall below the range of prices assumed in this analysis, then the expected pace of leasing might be lower than assumed for this analysis. Similarly, an actual oil price scenario above the price range stipulated in the analysis could generate higher expected rates of leasing. Changes in the pace of leasing will cause modifications in the total estimates of net social value of program alternatives, and will also change the distribution of value between value estimates for resources expected to be leased during the 5-Year Program and value associated with resources remaining available for lease after this 5-Year Program. However, as long as economically appropriate lease terms are employed (e.g., minimum bid requirements, royalty rates, etc.), the comparison of estimated value for program alternatives relative to the base schedule would not be significantly affected. Program options which add or accelerate sales in the schedule would continue to show increases, on the whole, compared to the base schedule, while options which defer sales would, on the whole, be expected to result in lower value relative to the base schedule.

The reason is that having a specific planning area on the lease sale schedule simply affords the Nation an opportunity to lease some of the resources in that area at the designated time in the schedule. The lease terms employed in the offering can be designed to help ensure that only those geological prospects, which are estimated to be ripe for investment, will be sold. Thus, as long as the net social value from holding a sale is positive, and lease terms are appropriately set, then earlier or more frequently held offerings tend to be more valuable, for any price path and resulting pace of leasing. Similarly, the program alternatives with subarea deferrals, which are estimated to leave more resources availabile for lease, will tend to be more valuable, on the whole, for any price path and resulting pace of leasing.



On the other hand, the value of a particular schedule, in which resources are leased over time beginning in mid-1987, depends upon a broader set of factors than "leasable" resources to generate sale-specific resource acquisitions. These additional factors which must be considered in the valuation analysis for estimates of resources which are expected to be leased include:

- the entire range of leasable resources under different economic conditions;
- the aggregate cost of transportation networks;
- the estimates of the growth of economically recoverable and leasable resources through time, assuming increases in real oil prices;
- consideration that alternative estimates of resource potential may be calculated by bidders and reflected in the range of industry interest for particular areas;
- the possibility that some of the tracts leased and explored by firms with optimistic expectations might turn out to contain resources that are worth developing even though they would not have been worth the expense of leasing and exploration had the firms had accurate knowledge of the size of the accumulation; and
- the possibility that early exploration in frontier areas can reveal the presence of oil and gas, thereby increasing the probability of discovery on the prospects remaining to be explored. Such increases in the probability of success can change the status of prospects from developable to leasable.

Thus, while "leasable" resources influence the expectations of resources which could be leased for each sale, the aggregate amount of resources projected to be leased in a given planning area over a 5-year period is not constrained by the "leasable" resources estimated for the net economic value calculations, but will be less than or equal to the estimated amount of economically recoverable resources for that planning area.

Estimates of resources expected to be leased by sale were made for the 5-year program schedule only (except for the California analysis, as described below). The balance of remaining economically recoverable resources were valued as if leased in the first appropriate year after this 5-year program. In other words, for some planning areas, remaining unleased resources were assumed to be available for lease in mid-1993, at the beginning of the next 5-year program. For other planning areas, where 5-year program sales were scheduled for 1991 or 1992, the remaining unleased resources were assumed to be available for lease 3 years after the scheduled sale, consistent with the SID proposal for a triennial pace of leasing. This simplifying assumption makes it possible to compare program alternatives without making judgments as to how resources may be sold under future 5-year programs. However, since the value of remaining resources was computed using a different assumption from that used for valuing 5-year program leasing, the resulting values should not be added together. The different program alternatives can be compared by examining both elements--value of the 5-year program and value of remaining resources--across each alternative.

The results of the valuation analysis for the California proposals are presented separately because of a slight change in the methodology used to value remaining unleased resources. Since two of the California proposals (i.e., Congressman Regula's and Congressman Panetta's) contained provisions for staged subarea deferrals beyond this 5-year program, it was necessary, for analytical purposes, to extend the valuation methodology used for the 5-year element to the remaining resources; that is, to project resources expected to be leased beyond the 5-Year program given the stated provisions of each proposal. The triennial pace of lease sales was assumed to continue for future 5-year programs. Under this methodology, resulting values can be disaggregated to examine value associated with only the 5-Year leasing component, or aggregated to examine total net social value for the 5-year program leasing and the leasing of remaining resources.

Table 1 reflects the amounts of resources projected to be leased for this analysis. Table 1.a displays the amounts used for valuation analysis of the California proposals. The estimates are consistent with those used in the 5-year Program environmental impact analysis except that EIS projections and assumptions are based on the total conditional resource estimates of each planning area, while the valuation analysis projections are related to the risked resource estimates. The difference between conditional and risked estimates is discussed in part II.B of the SID. Basically, the conditional numbers reflect resource potential of a planning area assuming that the area is hydrocarbon-prone. The conditional estimates are used in the EIS to capture potential environment consequences, if hydrocarbons are discovered. On the other hand, risked estimates are used in the economic analysis to reflect expected value. By removing the assumption that an area is hydrocarbon-prone, the risked estimates reflect the chance that the entire planning area could contain no hydrocarbons. The consequence of using different resource estimates is that the EIS discussion of potential environmental consequences is based on relatively larger estimates of resources leased and developed in some planning areas.

Estimating Net Social Value

Net social value estimates are calculated by subtracting social cost estimates from net economic value estimates for each planning area. The net economic value estimates for leasable resources derived in Appendix F were used to estimate a value at the time of sale for the resources expected to be leased. Valuation analysis was done for both a low and high price case. These price cases are based upon 1984 starting oil prices of $14 and $29 per barrel, respectively. (This corresponds to about $15.75 and $32.50, expressed in 1987 dollars). Resources were assumed to be sold in order from the highest valued prospects to the lowest valued (see Appendix F, Table 7). Where projections of resources expected to be leased exceeded the resources which were classified as leasable for the mid-1987 net economic value calculations, value was inferred using an approach developed in Appendix F. This approach calculates the economic value for resources in those prospects that are assumed to have a zero private value; i.e., they are marginally worth leasing. In other words, after all higher valued resources in a planning area are leased, any other additional resources leased are assumed to have marginal private value. Using the prospect-specific information as previously modeled, the level of resources in a prospect which would yield some marginal measure of private value can be re-computed. From the revised level of resources, an estimate of net economic value could be generated.



Table 1

Resources Expected to be Leased for Valuation Analysis

| Planning Area | 5-Year Program Leasing (mid-1987 to mid-1992) No. Sales* | Oil & Gas Resources Expected to be Leased Million BOE* | Remaining Unleased Oil & Gas Resources Million BOE** |
|---|---|---|---|
| **1. Option A.2.a -- 2/86 Proposed Program (as updated)** | | | |
| North Atlantic | 2 | 66 | 284 |
| Mid-Atlantic | 1 | 199 | 791 |
| South Atlantic | 1 | 75 | 865 |
| Western Gulf of Mexico | 5 | 1532 | 3098 |
| Central Gulf of Mexico | 5 | 2203 | 2367 |
| Eastern Gulf of Mexico | 2 | 120 | 460 |
| Southern California | 2 | 525 | 595 |
| Central California | 1 | 132 | 118 |
| Northern California | 2 | 248 | 202 |
| Oregon-Washington | 1 | 49 | 101 |
| Beaufort Sea | 2 | 439 | 21 |
| Chukchi Sea | 2 | 230 | 310 |
| Norton Basin | 1 | 30 | 40 |
| Navarin Basin | 2 | 631 | 459 |
| St. George Basin | 1 | 227 | 383 |
| N. Aleutian Basin | 1 | 79 | 11 |
| Shumagin | 1 | 9 | 1 |
| Gulf of Alaska | 1 | 28 | 122 |
| Cook Inlet | 1 | 7 | 3 |
| Kodiak | 1 | 21 | 9 |
| Hope | 1 | 8 | 2 |
| **2. Option A.2.b -- add sale in Straits of Florida** | | | |
| Straits of Florida | 1 | 6 | 14 |
| **3. Option A.2.c -- defer sales in up to 6 planning areas** | | | |
| North Atlantic | - | - | 350 |
| Southern California | - | - | 1,120 |
| Central California | - | - | 250 |
| Northern California | - | - | 450 |
| Oregon-Washington | - | - | 150 |
| N. Aleutian Basin | - | - | 90 |
| **4. Option A.2.d -- biennial sales in up to eight planning areas** | | | |
| Eastern Gulf of Mexico | 2 | 120 | 460 |
| Southern California | 2 | 465 | 655 |
| Central California | 2 | 189 | 61 |
| Northern California | 2 | 248 | 202 |
| Beaufort Sea | 3 | 460 | - |
| Navarin Basin | 3 | 726 | 364 |
| St. George Basin | 2 | 306 | 304 |
| N. Aleutian Basin | 2 | 82 | 8 |

Table 1 (continued)

Resources Expected to be Leased
for Valuation Analysis

| Planning Area | 5-Year Program Leasing (mid-1987 to mid-1992) No. Sales* | Oil & Gas Resources Expected to be Leased Million BOE** | Remaining Unleased Oil & Gas Pesources Million BOE** |
|---|---|---|---|
| **5. Option A.2.g -- new schedule Alternative** | | | |
| Central California | 1 | 132 | 118 |
| Oregon-Washington | 1 | 49 | 101 |
| Kodiak | - | - | 30 |
| **6. Option A.1.b -- additional subarea deferrals** | | | |
| North Atlantic | 2 | 60 | 200 |
| Mid-Atlantic | 1 | 199 | 791 |
| South Atlantic | 1 | 71 | 729 |
| Eastern Gulf of Mexico | 2 | 120 | 460 |
| Southern California | 2 | 525 | 575 |
| Central California | 1 | 126 | 114 |
| Northern California | 2 | 232 | 168 |
| Oregon-Washington | 1 | 49 | 101 |
| St. George Basin | 1 | 227 | 383 |
| N. Aleutian Basin | 1 | 79 | 11 |
| Norton Basin | 1 | 30 | 40 |
| Beaufort Sea | 2 | 439 | 21 |
| **7. Option A.1.f -- IRM proposal** | | | |
| North Aleutian Basin | 1 | 79 | 11 |
| Navarin Basin | 2 | 631 | 459 |
| Norton Basin | 1 | 26 | 14 |
| St. George Basin | 1 | 222 | 308 |

* Includes sales which may be designated as frontier exploration sales under options A.2.e.i or ii
** BOE = Barrels of Oil Equivalent



Table 1.a

Resources Expected to be Leased
for Valuation Analysis

- California Program Alternatives -

| California Planning Areas | 5-Year Program Leasing (Mid-1987 to mid-1992) no. Sales | Oil & Gas Resources Expected to be Leased Million BOE* | Leasing of Remaining Oil & Gas Resources no. Sales | million BOE* (mid-1992 to mid-2000) | million BOE* (mid-2000 and beyond) |
|---|---|---|---|---|---|
| **1. Option A.1.a -- 2/86 Proposed Program (as updated)** | | | | | |
| Northern California | 2 | 248 | 9 | 81 | 121 |
| Central California | 1 | 132 | 4 | 119 | 9 |
| Southern California | 2 | 525 | 8 | 270 | 325 |
| **8. Option A.1.c -- California Governor's proposal** | | | | | |
| Northern California | 2 | 229 | 9 | 72 | 99 |
| Central California | 1 | 90 | 4 | 78 | 2 |
| Southern California | 2 | 444 | 5 | 142 | 84 |
| **9. Option A.1.d -- Congressman Regula's proposal** | | | | | |
| Northern California | 2 | 189 | 11 | 133 | 76 |
| Central California | 1 | 125 | 4 | 117 | 8 |
| Southern California | 2 | 517 | 8 | 272 | 291 |
| **10. Option A.1.e -- Congressman Panetta's proposal** | | | | | |
| Northern California | 1 | 40 | 4 | 84 | 6 |
| Central California | 1 | 39 | 2 | 0 | 11 |
| Southern California | 2 | 219 | 18 | 168 | 503 |
| **11. Option A.1.g -- Amalgamated proposal** | | | | | |
| Northern California | 2 | 219 | 7 | 65 | 76 |
| Central California | 1 | 128 | 4 | 113 | 4 |
| Southern California | 2 | 522 | 8 | 264 | 277 |

* BOE = Barrels of Oil Equivalent

Because the net economic value estimates reflect value as of the beginning of the 5-Year Program, the estimates were adjusted to reflect the gradual increase in value for resources expected to be sold in later years. This adjustment was made by applying a 1-percent annual real rate of price growth to the revenue streams associated with each economic value category, while assuming that the cost streams remain constant. The resulting rate of growth in net economic value could then be used to approximate the adjusted net economic value of sales for the years in which they are scheduled under each program alternative. From these values, social costs were deducted to arrive at net social value at the time of sale for those resources expected to be leased in each sale. The social cost per barrel estimates used in this analysis were taken from Appendix G. /1 The net social value estimates at the time of sale were then discounted to express value in 1987 dollars (at an 8 percent real annual discount rate) to enable comparison of program alternatives on the same basis--i.e., in 1987 dollars.

Results of the valuation analysis are discussed and summarized in Part III of this SID. Table 2 shows the detailed results for each program alternative (except for the California proposals). Note that for each alternative to the Proposed Program schedule, results for only those planning areas which would be affected by the particular options are displayed. Table 2.a shows the valuation results for the California proposals displayed by planning area.

In Part III, Table 17.3 shows the estimated aggregate value of the California Proposals. However, the relative results differ somewhat when examining the proposals on a planning area basis. In the Northern California planning area, for example, the total value of the Governor's proposal is comparable to the total value of the Regula proposal and significantly exceeds the total value of the Panetta proposal.

In the Central and Southern California planning areas, the total value of the Regula proposal exceeds both the value estimated for the Governor's proposal and the value estimated for the Panetta proposal.

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1/ Social cost estimates in Appendix G were generated for each program alternative based on the level of resources projected to be leasable. These social cost estimates are used in the net social value calculations as seen in Table 12.4 of the SID. Resources expected to be leased in the valuation analysis are based upon estimates of economically recoverable resources and therefore are not limited by estimates of leasable resources. For this reason, the social cost per barrel estimates used for each program alternative in the valuation analysis were taken from Appendix G based on the level of resources which most closely approximated the total amount of economically recoverable resources estimated for each alternative. Social costs per barrel are a linear function of total resources, with a fixed cost component associated with pipelines and other infrastructure. Any error associated with approximating social costs for total economically recoverable resources would be related to changes in the fixed cost component of social costs and is expected to be minor--especially given that the social cost estimates are a small fraction of the total net social value estimates. The relative comparisons of proposals would not be affected by the approximations.



Table 2

Valuation of Program Alternatives
($1987 Millions)

| Planning Area | Discounted Net Social Value: Low Price Case* — 5-Year Program Leasing (Mid-1987 to Mid-1992) | Low Price Case* — Value of Remaining Unleased Resources | High Price Case* — 5-Year Program Leasing (Mid-1987 to Mid-1992) | High Price Case* — Value of Remaining Unleased Resources |
|---|---|---|---|---|
| 1. Option A.2.a -- Proposed Program Schedule (as Updated) | | | | |
| North Atlantic + | $77 | $180 | $215 | $439 |
| Mid-Atlantic + | $189 | $444 | $744 | $939 |
| South Atlantic + | $98 | $681 | $344 | $2,250 |
| Western Gulf of Mexico | $3,201 | $3,647 | $10,858 | $14,481 |
| Central Gulf of Mexico | $6,005 | $3,021 | $15,563 | $10,171 |
| Eastern Gulf of Mexico | $100 | $341 | $716 | $1,419 |
| Southern California | $983 | $395 | $3,304 | $1,256 |
| Central California | $213 | $88 | $924 | $350 |
| Northern California | $465 | $124 | $1,713 | $487 |
| Oregon-Washington + | $122 | $93 | $348 | $209 |
| Beaufort Sea | $112 | $6 | $793 | $20 |
| Chukchi Sea | $59 | $82 | $314 | $352 |
| Norton Basin + | $8 | $12 | $53 | $81 |
| Navarin Basin | $324 | $155 | $1,940 | $706 |
| St. George Basin + | $63 | $122 | $520 | $677 |
| N. Aleutian Basin | $22 | $3 | $90 | $11 |
| Shumagin + | $3 | $0 | $18 | $2 |
| Gulf of Alaska + | $8 | $35 | $37 | $195 |
| Cook Inlet + | $2 | $1 | $14 | $5 |
| Kodiak + | $6 | $3 | $36 | $14 |
| Hope + | $3 | $1 | $13 | $3 |
| Totals: | $12,061 | $9,431 | $38,556 | $34,065 |
| 2. Option A.2.b -- add sale in Straits of Florida | | | | |
| Straits of Florida | $7 | $13 | $26 | $37 |
| 3. Option A.2.c -- defer sales in up to six planning areas | | | | |
| North Atlantic | - | $251 | - | $625 |
| Southern California | - | $1,235 | - | $4,100 |
| Central California | - | $266 | - | $1,074 |
| Northern California | - | $526 | - | $1,953 |
| Oregon-Washington | - | $205 | - | $523 |
| N. Aleutian Basin | - | $26 | - | $95 |
| 4. Option A.2.d -- biennial sales in up to eight planning areas | | | | |
| Eastern Gulf of Mexico | $100 | $349 | $734 | $1,495 |
| Southern California | $945 | $460 | $3,097 | $1,610 |
| Central California | $267 | $38 | $1,146 | $151 |
| Northern California | $471 | $130 | $1,743 | $538 |
| Beaufort Sea | $116 | $0 | $824 | $0 |
| Navarin Basin | $361 | $118 | $2,146 | $531 |
| St. George Basin | $81 | $97 | $705 | $533 |
| N. Aleutian Basin | $22 | $2 | $95 | $8 |

Table 2 (continued)

| Planning Area | Discounted Net Social Value: Low Price Case*: 5-Year Program Leasing (Mid-1987 to Mid-1992) | Low Price Case*: Value of Remaining Unleased Resources | High Price Case*: 5-Year Program Leasing (Mid-1987 to Mid-1992) | High Price Case*: Value of Remaining Unleased Resources |
|---|---|---|---|---|
| 5. Option A.2.g -- new schedule Alternative | | | | |
| Central California | $204 | $88 | $870 | $350 |
| Oregon-Washington | $115 | $90 | $327 | $201 |
| Kodiak | - | $9 | - | $50 |
| 6. Option A.1.b -- additional subarea deferrals | | | | |
| North Atlantic | $71 | $115 | $183 | $282 |
| Mid-Atlantic | $189 | $444 | $744 | $939 |
| South Atlantic | $93 | $569 | $326 | $1,892 |
| Eastern Gulf of Mexico. | $100 | $333 | $716 | $1,399 |
| Southern California | $982 | $382 | $3,302 | $1,208 |
| Central California | $208 | $87 | $895 | $343 |
| Northern California | $445 | $110 | $1,644 | $418 |
| Oregon-Washington | $122 | $93 | $348 | $209 |
| St. George Basin | $63 | $122 | $520 | $677 |
| North Aleutian Basin | $22 | $3 | $90 | $11 |
| Norton Basin | $8 | $12 | $53 | $81 |
| Beaufort Sea | $112 | $6 | $793 | $20 |
| 7. Option A.1.f -- IRM proposal | | | | |
| North Aleutian Basin | $22 | $3 | $90 | $11 |
| Navarin Basin | $324 | $155 | $1,940 | $706 |
| Norton Basin | $7 | $4 | $52 | $28 |
| St. George Basin | $61 | $98 | $508 | $541 |

+ Planning area includes one or more sales which may be designated as frontier exploration sales under options A.2.e.i or ii.

Table 2.a

VALUATION OF CALIFORNIA PROPOSALS--DISPLAYED BY PLANNING AREA

DISCOUNTED NET SOCIAL VALUE OF RESOURCES EXPECTED TO BE LEASED DURING THE 5-YEAR PROGRAM & REMAINING ECONOMICALLY RECOVERABLE RESOURCES ($1987 MILLIONS)

| CALIFORNIA PROPOSALS | LOW PRICE CASE* VALUE FOR CALIFORNIA PLANNING AREAS: 5-Year Program leasing (mid-1987 to mid-1992) | Leasing of Remaining Resources**: (mid-1992 to mid-2000) | Leasing of Remaining Resources**: (mid-2000 and beyond) | HIGH PRICE CASE* VALUE FOR CALIFORNIA PLANNING AREAS: 5-Year Program leasing (mid-1987 to mid-1992) | Leasing of Remaining Resources**: (mid-1992 to mid-2000) | Leasing of Remaining Resources**: (mid-2000 and beyond) |
|---|---|---|---|---|---|---|
| NORTHERN CALIFORNIA | | | | | | |
| 2/86 Proposal | $465 | $51 | $46 | $1,713 | $221 | $142 |
| Governor | $384 | $41 | $39 | $1,456 | $182 | $116 |
| Regula | $314 | $128 | $30 | $1,185 | $478 | $92 |
| Panetta | $52 | $26 | $47 | $220 | $93 | $92 |
| Amalgamated Proposal | $407 | $39 | $32 | $1,497 | $172 | $96 |
| CENTRAL CALIFORNIA | | | | | | |
| 2/86 Proposal | $213 | $85 | $0 | $924 | $325 | $0 |
| Governor | $136 | $53 | $1 | $608 | $211 | $2 |
| Regula | $195 | $83 | $4 | $843 | $331 | $9 |
| Panetta | $52 | $6 | $0 | $232 | $22 | $0 |
| Amalgamated Proposal | $206 | $81 | $2 | $894 | $315 | $4 |
| SOUTHERN CALIFORNIA | | | | | | |
| 2/86 Proposal | $983 | $172 | $143 | $3,304 | $715 | $329 |
| Governor | $714 | $91 | $42 | $2,529 | $251 | $88 |
| Regula | $876 | $174 | $131 | $3,091 | $685 | $283 |
| Panetta | $524 | $134 | $150 | $1,547 | $570 | $492 |
| Amalgamated Proposal | $898 | $168 | $126 | $3,163 | $654 | $270 |

* A low and high price case is used to capture the effects on value from alternative price path assumptions. The low and high starting prices of $14 and $29 per barrel reflect a range of weighted average FOB prices of U.S. imports of oil at the time when the 5-year program analysis began in 1984. For the Pacific region, these 1984 prices would equate to about $15 and $32 respectively, if expressed in 1987 dollars. For both the low and high cases, these oil prices are assumed to grow at a 1-percent annual real rate. As a simplifying assumption, resources expected to be leased in the series of sales for each proposal remain the same under both price cases.

** Assumes deferred subareas are not available for leasing after deferral period runs out.

In the Southern California planning area, the magnitude and the location of the resources in the subarea deferrals proposed by the Governor result in a total net social value estimate of the Governor's proposal which approximates the net social value estimated for the Panetta proposal. The restriction on the timing of offering industry interest tracts under the Panetta proposal results in a lower value for the 5-year program relative to the Governor's proposal. However, the relatively high estimates of value for the leasing of remaining oil and gas resources subsequent to the 5-year program is the reason that the value of the Panetta and Governor's proposals are approximately the same in total for Southern California. The Regula proposal's value estimate in this planning area exceeds the estimates for the Governor's and the Panetta proposals.

The estimates of net social value for alternatives to the 2/86 proposal, including the amalgamated proposal, are below the estimated value for the 2/86 proposal for all 3 planning areas. The net social value estimates for the amalgamated proposal most closely approximate the estimates for the Regula proposal in the Central and Southern California planning areas and the estimate for the Governor's proposal in Northern California.

# APPENDIX S

# LIMITATIONS OF THE TECHNICAL SECTION 18 ANALYSES

## Limitations of the Technical Section 18 Analyses

There are inherent and unavoidable limits on the precision of the analyses which have been performed under section 18. The limits of the analyses required under section 18 are explained in Part II.B and Appendices E, F, G, and I. A combined summary account of those explanations appears in this appendix.

The court addressed this issue in California v. Watt (II) in the following terms:

> It is important to understand what is being evaluated . . . . [T]he factual basis and the methodology used by the Secretary in various aspects of the cost benefit analysis . . . fall within what the court in Watt I described as the "frontiers of scientific knowledge." The facts used by the Secretary in performing the analysis are largely predictive in nature, and the methodology utilized was necessarily novel because this type of analysis has not been performed extensively in the past. Thus, as the court in Watt I observed, great deference is afforded to the Secretary in these areas. "Where existing methodology or research in a new area of regulation is deficient, the agency necessarily enjoys broad discretion to attempt to formulate a solution to the best of its ability on the basis of available information." Therefore, although we are obligated to review the factual findings of the Secretary in order to determine that they are supported by substantial evidence in the record, we realize that these findings must be somewhat speculative. Further, we are required to sustain the methodology and assumptions made by the Secretary if they are reasonable. /1

This SID incorporates the following approaches, which reflect a recognition of those limitations:

a. Evaluating the Adequacy of Data

In order to provide a way of evaluating the results of the various technical analyses, an indication will be given of the adequacy of the data on which they are based. For example, the grid coverage and quality of the geologic and geophysical data which is the basis of much of the analysis in this SID ranges from "Excellent" for some areas to "Very Poor" in others. Table 12 in the SID and Appendix E contain an evaluation of such data for each planning area.

b. Analyzing the Sensitivity of the Analyses to Key Assumptions

Where reasonable changes in technical assumptions could produce significant changes in the results of analyses, sensitivity analyses are provided. These analyses show the effects of different assumptions on the results of the technical analyses. For example, the analysis of net economic value includes a sensitivity test which shows the variation of leasable resource estimates given starting oil prices ranging from $14 to $29 per barrel (see Appendix F).

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/1 California v. Watt (II) at 600



c. Providing Ranges and Variations of Estimates

Given the uncertainties involved in the data, ranges and variations of estimates are an informative supplement to measures of central tendency and point estimates. The SID provides a range for conditional estimates of unleased undiscovered OCS oil and gas resources as of March 1985 (SID Table 1). Variations of estimates corresponding to assumed starting oil prices of $14 to $29 per barrel are also provided in the SID for net economic value, social costs, and net social value.

d. Overestimation of Costs

A cautious approach in formulating the technical analyses is taken, erring on the side of understating economic benefits to the Nation and overstating social costs to the Nation, while still aiming at a reasonable estimation of both (see Appendix G).

e. Providing Perspective on the Estimates of Costs and Benefits

In making comparisons between planning areas based on the cost-benefit analysis, the relative values calculated for OCS areas are accorded much more importance than the absolute values. Further, OCS areas with estimates within the same general range of value are not considered to differ for purposes of program formulation. Thus, for example, planning areas are formed into groups and subgroups whose members are treated alike, all things being equal, for the scheduling of sales (see Part II.D and Part III.A.2).

f. Supplementing Government Analyses with Public Comments

Pursuant to section 18, consultation with and comments by parties outside the Federal Government are used to provide additional information. The consideration of outside comments is an important element in the decisionmaking process. Responses to the March 1985 requests for comments are summarized in Appendices B and D.

g. Highlighting the Role of Judgment in Interpreting the Technical Analyses and Formulating the Leasing Program

The fact that the technical analyses performed pursuant to section 18 have inherent and unavoidable limits has important implications both for the decisionmaking process leading to the new 5-year program and for the structure of that program. In terms of the decisionmaking process, the limits of the quantitative analyses make clear the prudence of the court's opinion in California v. Watt (II). The court found that the Secretary's decision on the leasing program is to be based on a consideration of quantitative analyses rather than determined by the results of those analyses in a mechanistic way. Thus, there remains for the Secretary substantial scope for the exercise of judgment based on non-quantifiable considerations and limitations on the quantitative analyses. These considerations and limitations are highlighted in the SID and its appendices.

Recognition of the limitations of the technical analyses and projections of future conditions also casts light on the kind of leasing program appropriate to meet the objectives specified by Congress and the National Energy Policy Plan. The many uncertainties which affect planning for OCS leasing make clear the value of flexibility in the OCS leasing program. Indeed, the issue in formulating a new program is not whether to provide for flexibility, but how. For example, the 5-year schedule responds easily to declines in prices and other factors, which tend in the direction of less bidding interest by industry or the deferral or cancellation of sales. The 5-year program is characteristically rigid, however, with respect to responding to circumstances which call for the addition of sales. This issue will be discussed further in Part III of this SID. Comments on this issue were requested in the March 1985 Federal Register Notice and are summarized in Appendix B.

Summary Discussion of the Limits of the Technical Analyses

--Geological and Geophysical Data

Geological and geophysical data are typically the beginning point for assessing the consequences of OCS oil and gas leasing. A great amount of such data has been accumulated and interpreted by the MMS and other parties (see Appendix E). Nonetheless, the following limiting factors about that data base need to be considered.

The collection and analysis of data for attempting to predict the presence of oil and gas are costly. Although some data are collected by the MMS, most are collected by firms exploring for oil and gas and are made available to MMS by those firms. Thus, the extent and location of the geological and geophysical data gathered have been determined primarily by private firms' assessment of the potential payoffs from acquiring leases and exploring for oil and gas. Since this process is governed by economic factors such as oil prices as well as the opportunity to acquire leases and find oil and gas, knowledge of estimated undiscovered resources is inherently incomplete and is limited in areas and prospects that have not been made available for leasing or have not appeared economically attractive to one or more companies. A paucity of data for an area greatly increases the uncertainty surrounding its geologic characteristics and thus its resource potential. More emphasis must be placed on indirect means of assessment, such as comparison to geologically similar basins where there has been significant exploration. In these cases, the estimates are only as good as the selection of analogs; that is, the estimates are highly speculative. In this connection, see Appendix E.

In addition, the estimation of undiscovered resources typically assumes a set of prices and costs consistent with current expectations. Extrapolation to include resources that are recoverable only at significantly higher price levels would require a basic reevaluation of existing geologic data as well as the accumulation of additional data not now available because of its high cost



and limited private value. Estimates of resources that are economic under current expectations thus potentially understate the resources that are likely to be found and discovered in the future. Even for areas and prospects for which there are substantial seismic data, the resource potential can only be measured in probabilistic terms until exploratory wells have been drilled. Thus, one hundred prospects may each have a one-in-ten chance of containing 100 million barrels of oil. Before drilling, each must be regarded as having the same resource potential. Drilling could reveal, however, that 90 of the 100 prospects had no oil while 10 have 100 million barrels each. The same holds true for large areas that have not had exploratory drilling. Thus, a leasing program must be based on probabilistic estimates of resources for various areas despite the fact that some areas will turn out to have no oil and gas while others have a great deal.

There are also technological limits to the available data. Interpretation of seismic data is imperfect and may leave many deposits unidentified for many years. Even the targeting of prospects for drilling involves far more failures than successes.

The greatest element of cost--drilling wells--is also the most crucial to the evaluation of the data because the actual presence of hydrocarbons in a geologic structure can only be established by drilling. Drilling wells--often many wells, most of which are dry holes--is necessary before deposits of oil and gas can be discovered and delineated--if they are present in an area at all. Over 100 dry holes at a cost of up to 10 million dollars each were drilled before the recent hydrocarbon discoveries in the Canadian North Atlantic. The history of exploration in Prudhoe Bay and in the North Sea is comparable. Over 100 exploratory wells have been drilled in the OCS off the Atlantic Coast States, in the Eastern Gulf of Mexico, in the Bering Sea, in the Gulf of Alaska, and in Cook Inlet without a commercial discovery.

Section 102(9) of the OCS Lands Act clearly recognizes the incomplete nature of geologic knowledge in mandating that ". . . the extent of oil and natural gas resources of the Outer Continental Shelf [be] assessed at the earliest practicable time." Since the OCS Lands Act for the most part ties the right to drill to the acquisition of a lease, the OCS leasing program has to be seen, at least in part, as a program that facilitates the acquisition of better geological data by potential producers for use by them and by the Government. The leasing program thus has a major influence on progress in resource assessment.

--Economic Projections

The projection of the economic benefits of OCS leasing also reflects the unavoidable limits to precision in OCS program planning (see Part II.B and Appendix F). The chief limits here are the uncertainties attendant on the prediction of future oil prices or rates of price increases or decreases, and the selection of a discount rate.

The quadrupling of oil prices (in constant dollars) between 1973 and 1981--and their subsequent decline--makes clear the difficulty of predicting prices. This difficulty is compounded by the long time period which the prediction must cover. The period from leasing to the end of production, if there is any production, is generally projected to be on the order of 20 to 30 years.

Geopolitical factors cause further limits on the precision of price predictions used in planning for OCS leasing. A major, long-term change in the political order of a few or even only one nation in the Middle East could have enormous effects on world oil supplies and prices. The 5-year OCS leasing program must take into account this possibility as a matter of prudence given the purposes of the OCS Lands Act Amendments. This consideration is discussed further in Part II.A.

The comparison of economic benefits among planning areas is facilitated by estimation of the net economic value of the resource potential in each area. This requires the calculation of the net present value of the stream of estimated production revenues minus the stream of exploration, production, and transportation costs which are projected to occur over time. This gives the value of Federal receipts and lease profits discounted to January 1987 which is equivalent to the production revenues (net of costs) over the economic life of the venture.

The calculation of net present values requires the selection of a discount rate. The discount rate is a measure of the time value of money representing how much more a dollar of benefits or costs is worth to us in the present than in the future. The selection of a discount rate thus inevitably calls for a judgment about how much the country will value benefits which will accrue in the future as opposed to the present. There is controversy among economists about the basis for selection of a discount rate. There is also uncertainty about the future economic conditions which it is intended to reflect. Thus there is uncertainty about the proper value of this important factor.

Because of these inherent uncertainties in the data, projections, and methods used to produce quantitative estimates of benefits and costs, efforts have been made to analyze qualitatively the effects of different aspects of the OCS leasing program under different future conditions. Particular attention has been paid to the effects of leasing on the timing of investments in OCS exploration and development and on the benefits to the U.S. economy under different future conditions in the world oil market.

--<u>Estimates of Social Costs</u>

Like the analysis of economic benefits, the analysis of social costs also bears the burden of predicting prices and selection of a discount rate (see Part II.B and Appendix G). The analysis of social costs has assumed the additional burden of quantifying certain potential costs of oil and gas development not valued by the market. This effort helps to provide an estimate of the social cost of oil and gas development in dollars so that the overall net social value (net economic benefits minus social costs) can be computed for oil and gas development in each planning area. This cost-benefit approach was part of the guidelines issued by the court in <u>California v. Watt</u> (I) and its execution was validated by the court in <u>California v. Watt (II)</u>.

Estimates of social costs which are not valued in the market cannot be considered entirely comparable to estimates of net economic value. The reason for this is that the estimation of social costs expressed in dollar terms are not generally



accepted measures, unlike the market values used in the net economic value analysis. In addition, beyond the comparison of costs and benefits expressed in dollar terms, qualitative as well as quantitative information needs to be considered.

<u>--Analysis of Relative Marine Productivity and Environmental Sensitivity</u>

The analysis of the relative marine productivity and environmental sensitivity of OCS planning areas called for by section 18 has limits comparable to those of the analysis of social costs (see Part II.B.3 and Appendix I). The SID analysis of social costs quantifies some of the externalities not included in the calculation of net economic value. The SID analysis of relative marine productivity and environmental sensitivity, at least in part, develops numerical coefficients of the level of sensitivity of individual habitats and biota which are then used to generate combined productivity and sensitivity measures which are used to compare OCS planning areas. The calculation of productivity and sensitivity measures is subject to limitations such as the abstract nature of the measures as contrasted to the factors which they represent and the unavoidable need for professional judgment not reducible to technique in the determination of the sensitivity coefficients. These limitations affect the marine productivity and environmental sensitivity analysis both insofar as that analysis is to be considered in itself and insofar as it serves as an input to the analysis of social costs.

In addition, the availability of marine productivity and sensitivity data is limited by the data base available as the result of past investigations and the costliness of the acquisition of new information. The efforts of the MMS to acquire more data through its environmental studies program are described in Appendix H.

# APPENDIX T

## Estimated Appropriations and Staffing Requirements

## for

## Proposed Final 5-Year Leasing Program

# APPENDIX T

## Estimated Appropriations and Staffing Requirements for Proposed Final 5-Year Leasing Program

**Format**

Section 18(b) of the OCS Lands Act, as amended (OCSLAA) requires that the 5-Year Program include an estimate of appropriations and staffing. The following tables provide estimates of appropriations and staffing levels of full-time equivalent (FTE) positions necessary to carry out two options of the Proposed Final Program (PFP).

The PFP has been developed and presented in a calendar year (CY) format. However, since Federal Government agencies receive funding and personnel ceilings on a fiscal year (FY) basis the tabular summaries of funds and staff are presented that way. It should be noted that although the effective date of the PFP would include only the fourth quarter of FY 1987 the entire appropriation has been included. Also note that the full costs for preparation of the 5-year program is not reflected in these figures since only Fiscal Years 1987 through 1992 are shown.

It also should be noted that resources for the prelease activities for Fiscal Years 1988 and beyond only provide estimated costs and FTE for those sales included in the two PFP options. There are no estimated resources included for the work on prelease planning activities for sales which would be included in the next 5-year program. The effect of this is that there appears to be a decline of needed resources in the outer FYs for the prelease processes (Categories I, II, and part of III).

Contrary to the prelease estimates, those of the postlease and general administration (Categories III, in part, IV and V) may not show a decline. These processes remain fairly constant, and, in the case of the postlease activities, may increase as production begins on leases issued from sales held in the earlier years of the 5-year program.

The estimated resources contain requirements from not only the Minerals Management Service (MMS) but other Department of the Interior Bureaus and Offices as well. It is important to note that these are initial estimates of resource requirements. Estimates may change as agency budgets are refined during the annual budget appropriations processes of the Department, the Office of Management and Budget (OMB) and the Congress.

Other Interior agencies are consulted during the OCS lease sale process but the associated costs are too incidental to be identified as specific budget and staffing requirements for the 5-Year program. Other Federal agencies such as the Coast Guard, Corps



of Engineers, National Oceanic and Atmospheric Administration (NOAA) and the Environmental Protection Agency (EPA) have a variety of regulatory responsibilities which are related to the general OCS program; but are not enumerated within section 18(b). The associated costs for these activities are appropriated directly to these agencies and are not included in this exercise.

Consistent with the resource data prepared for the last PFP (July 1982) the data included on these tables have been categorized by those activities as specified in accordance with subsections 1 through 4 of Section 18(b). The tables also include a General Administrative Activities Category to cover those activities not specifically listed in Section 18(b) but which must be included to fully reflect the cost of managing the post and prelease processes required to implement the PFP.

The development of the 5-year program, the various steps of the prelease consultation and planning process, and the oversight of exploration and production activities are an overlapping and continuous process. Any of several steps may generate information which may be applied at other steps in the overall administrative process. Thus, the section 18(b) categories are not a direct assessment of how MMS resources are budgeted or utilized in the administration of the program. These categories are discussed as follows:

**<u>1. Obtain resource information and any other information required to prepare the leasing program - [18(b)(1)]</u>**

A major activity included in the resource estimates for this category is the acquisition (reproduction costs) and analysis of Geological and Geophysical (G&G) data. This data is acquired and analyzed in order to first identify the broad areas and then specific tracts with geologic potential for oil and gas. These data are the basis for mapping and evaluating geological formations and the potential distribution of offshore resources. The data also provide input for determination of bid adequacy.

Also included in this category are activities involved in the development and maintenance of estimates of oil and gas reserves as mandated by the OCSLAA. Reserve inventories are generated from well and reservoir data and tabulated by individual field, reservoir, and lease. The analyses and mapping associated with reserve estimates directly support field and reservoir development and provide geological and engineering data required for lease sale evaluations.

Another activity included in this category is the Oil and Gas Information Program required by the OCSLAA which indicates that the MMS shall provide governors of affected States and, upon request, executives of affected local governments and other interested parties, data and information in the form of Summary Reports and Indexes. The summary Reports/Indexes are provided to aid States and local governments in planning for onshore impacts of OCS development and production operations. These Summary Reports/Indexes are updated annually.

**2. Analyze and interpret exploratory data and any other information that may be acquired under the OCSLAA - [18(b)(2)]**
Activities under this category provide related sets of technical and analytical inputs throughout the leasing process. Included are the development of resource estimates and economic resource evaluations and analyses. The initial focus is on assessing the potential resources of entire planning areas, then on areas considered for leasing, and finally on tracts receiving bids in a sale. Economic and engineering analyses of minimum economic field size, minimum bid level, and lease terms, among others, are carried out. These analyses are directly related to specific lease sales, and also provide necessary input for overall program decisions.

**3. Conduct environmental studies and prepare environmental documents - [18(b)(3)]**
This category includes the conduct of an environmental studies program which provides information necessary for prediction, assessment, and management of potential effects of oil and gas and other mineral activities on the OCS and adjacent coastal areas; to provide data to support regional and national information needs; and to help monitor postlease OCS operations. Included are the costs of managing this studies program and the actual cost of contracts awarded.

All activities related to the prelease environmental analysis process are included in this category, from the development of a Notice of Intent to prepare an EIS, through the scoping process which identifies issues and alternatives and the EIS process which includes preparation of a draft and final NEPA document and conduct of public hearings. The cost of special assessments needed for these NEPA documents (such as oil spill risk analyses and endangered species consultations) are included.

Also included in this category are the costs of environmental review and evaluation for postlease NEPA documents to insure that leasing and permitting actions are in accordance with all Federal environmental laws and that required Federal coordination occurs, such as for endangered species, archaeological resources, and coastal zone management.

**4. Supervise lease operations - [18(b)(4)]**
Activities under this category provide for the comprehensive and systematic review, approval, and supervision of lessee-conducted oil and gas drilling, development, and production operations on the OCS. This is accomplished through the review and approval or disapproval, if appropriate, of exploration plans, development and production plans, development operations, and recompletions and repairs; and through the issuance of permits, the inspection of lessee-conducted activities to assure compliance with governing requirements, and the taking of appropriate enforcement actions when requirements are not met.

Responsibilities under the OCSLAA require: coordination of approvals of OCS exploration plans and development and production plans with the affected States; conducting scheduled inspections



for each facility annually (with intermittent unscheduled inspections to assure regulatory compliance); and the assessment and collection of civil penalties for OCS infractions of Federal regulations.

Other activities include the coordination with other Federal agencies having OCS responsibilities and the conduct of independent analyses of OCS technologies to identify technology gaps and to assure the use of the best available and safest technologies. This program assists in the development of technical and operational requirements for leaseholders to assure safe, pollution-free operations. These requirements are incorporated into OCS orders, regulations, and the conditions for granting permits.

**5. General administrative activities - [not specifically stated in the OCSLAA]**
This category included resources for two areas of activities which do not readily fit into the above four. These activities include costs and FTE for direct program activities associated with the PFP and general offshore program as well as estimated cost for the executive/managerial direction and agency administrative support functions.

Examples of direct program activities include: preparing, issuing, and analyzing responses to the call for information; preparing decision materials for area identification; preparing sale decision documents; conducting the postsale analysis of bids to assure receipt of fair market value; and other lease administration activities. Costs for the review and expertise provided by the Office of the Solicitor (DOI) are also included in this category.

Examples of executive/managerial resource requirements would include estimated costs for the executive direction provided by the Office of the Director (MMS), the Associate and Deputy Associate Directors (MMS) as well as costs of other headquarters and regional management. An attempt has been made to provide estimated costs for other administrative support functions which also support the workload and activities of the PFP. These costs include payrolling, personnel management, procurement, space, communication and financial management activities.

**Assumptions**
The estimated costs of the OCS program are affected by many variables. These costs estimates have been prepared using the best available data such as historic program experience, current fiscal trends, Administration and Office of Management and Budget (OMB) guidelines, and the projected workload involved with the sales included in the 5-year program options.

**Table 1** reflects the estimated cost and FTE associated with the **Proposed Program Update Schedule** (options A.2.a and A.2.e.i.). **Table 2** reflects the estimated cost and FTE associated with the **New Schedule Alternative** (option A.2.g.).

DEPARTMENT OF THE INTERIOR

Minerals Management Service

Estimated Appropriation and Staffing Requirements
Proposed Final 5-Year Leasing Program



Options A.2.a and A.2.e.i (Table 14)
(Dollars in Millions)

| Category/Section of Act | FY 1987 a/ Funds | FY 1987 a/ Staff | FY 1988 b/ Funds | FY 1988 b/ Staff | FY 1989 Funds | FY 1989 Staff |
|---|---|---|---|---|---|---|
| I. Resource Information, Section 18(b)(1): | | | | | | |
| Minerals Management Service | $13,490.1 | 141.8 | $10,826.1 | 131.8 | $10,840.2 | 129.2 |
| II. Exploration Data, Section 18(b)(2): | | | | | | |
| Minerals Management Service | 7,141.3 | 112.7 | 7,441.0 | 112.7 | 7,462.4 | 112.7 |
| III. Environmental Activity, Section 18(b)(3): | | | | | | |
| Minerals Management Service | 34,987.9 | 286.6 | 35,146.7 | 283.3 | 41,640.6 | 283.0 |
| U.S. Fish and Wildlife Service | 125.0 | 2.0 | 125.0 | 2.0 | 100.0 | 2.0 |
| | 35,112.9 | 288.6 | 35,271.7 | 285.3 | 41,740.6 | 285.0 |
| IV. Supervision of Leasing Operations, Section 18(b)(4): | | | | | | |
| Minerals Management Service | 24,191.1 | 358.3 | 25,206.2 | 358.3 | 25,427.2 | 356.7 |
| U.S. Fish and Wildlife Service | 75.0 | 1.0 | 75.0 | 1.0 | 50.0 | 1.0 |
| | 24,266.1 | 359.3 | 25,281.2 | 359.3 | 25,477.2 | 357.7 |
| V. General Administration, | | | | | | |
| Minerals Management Service | 26,024.9 | 389.9 | 28,268.2 | 386.9 | 28,258.6 | 386.7 |
| Office of the Solicitor (DOI) | 350.0 | 7.0 | 350.0 | 7.0 | 350.0 | 7.0 |
| | 26,374.9 | 396.9 | 28,618.2 | 393.9 | 28,608.6 | 393.7 |
| Total Requirements: | | | | | | |
| Minerals Management Service | $105,835.3 | 1,289.3 | $106,888.2 | 1,273.0 | $113,629.0 | 1,268.3 |
| U.S. Fish and Wildlife Service | 200.0 | 3.0 | 200.0 | 3.0 | 150.0 | 3.0 |
| Office of the Solicitor (DOI) | 350.0 | 7.0 | 350.0 | 7.0 | 350.0 | 7.0 |
| | $106,385.3 | 1,299.3 | $107,438.2 | 1,283.0 | $114,129.0 | 1,278.3 |

a/ Funding and Staffing provided in this column reflect FY 1987 appropriations to the MMS.
b/ Funding and Staffing provided in this column reflect the FY 1988 request for MMS as submitted to the Department, 1/87.



DEPARTMENT OF THE INTERIOR

Minerals Management Service

Estimated Appropriation and Staffing Requirements
Proposed Final 5-Year Leasing Program



Options A.2.a and A.2.e.i (Table 14)
(Dollars in Millions)

| Category/Section of Act | FY 1990 c/ Funds | FY 1990 c/ Staff | FY 1991 c/ Funds | FY 1991 c/ Staff | FY 1992 c/ Funds | FY 1992 c/ Staff |
|---|---|---|---|---|---|---|
| I. Resource Information, Section 18(b)(1): | | | | | | |
| Minerals Management Service | $11,007.6 | 129.8 | $6,948.9 | 122.6 | $4,686.7 | 115.3 |
| II. Exploration Data, Section 18(b)(2): | | | | | | |
| Minerals Management Service | 7,134.6 | 106.7 | 7,300.8 | 110.7 | 6,302.0 | 90.3 |
| III. Environmental Activity, Section 18(b)(3): | | | | | | |
| Minerals Management Service | 37,966.4 | 302.0 | 33,785.4 | 266.1 | 13,666.1 | 163.2 |
| U.S. Fish and Wildlife Service | 80.0 | 2.0 | 60.0 | 2.0 | 50.0 | 1.0 |
| | 38,046.4 | 304.0 | 33,845.4 | 268.1 | 13,716.1 | 164.2 |
| IV. Supervision of Leasing Operations, Section 18(b)(4): | | | | | | |
| Minerals Management Service | 25,797.4 | 358.1 | 26,431.3 | 361.9 | 26,931.3 | 363.9 |
| U.S. Fish and Wildlife Service | 40.0 | 1.0 | 35.0 | 1.0 | 25.0 | 1.0 |
| | 25,837.4 | 359.1 | 26,466.3 | 362.9 | 26,956.3 | 364.9 |
| V. General Administration, | | | | | | |
| Minerals Management Service | 28,219.7 | 386.4 | 28,605.6 | 390.3 | 27,934.5 | 378.9 |
| Office of the Solicitor (DOI) | 350.0 | 7.0 | 350.0 | 7.0 | 350.0 | 7.0 |
| | 28,569.7 | 393.4 | 28,955.6 | 397.3 | 28,284.5 | 385.9 |
| Total Requirements: | | | | | | |
| Minerals Management Service | $110,125.7 | 1,283.0 | $103,072.0 | 1,251.6 | $79,520.6 | 1,111.6 |
| U.S. Fish and Wildlife Service | 120.0 | 3.0 | 95.0 | 3.0 | 75.0 | 2.0 |
| Office of the Solicitor (DOI) | 350.0 | 7.0 | 350.0 | 7.0 | 350.0 | 7.0 |
| | $110,595.7 | 1,293.0 | $103,517.0 | 1,261.6 | $79,945.6 | 1,120.6 |

c/ Resource estimates for the prelease activities for these years only reflect workload of the PFP; no estimates are provided for work on prelease planning activities for sales which would be included in the next 5-year program.

DEPARTMENT OF THE INTERIOR

Minerals Management Service

Estimated Appropriation and Staffing Requirements
Proposed Final 5-Year Leasing Program



Option A.2.g. (Table 16)
(Dollars in Millions)

| Category/Section of Act | FY 1987 a/ Funds | FY 1987 a/ Staff | FY 1988 b/ Funds | FY 1988 b/ Staff | FY 1989 Funds | FY 1989 Staff |
|---|---|---|---|---|---|---|
| I. Resource Information, Section 18(b)(1): | | | | | | |
| Minerals Management Service | $13,490.1 | 141.8 | $10,826.1 | 131.8 | $10,840.2 | 129.8 |
| II. Exploration Data, Section 18(b)(2): | | | | | | |
| Minerals Management Service | 7,141.3 | 112.7 | 7,441.0 | 112.7 | 7,462.4 | 112.7 |
| III. Environmental Activity, Section 18(b)(3): | | | | | | |
| Minerals Management Service | 34,987.9 | 286.6 | 35,146.7 | 283.3 | 40,099.5 | 282.3 |
| U.S. Fish and Wildlife Service | 125.0 | 2.0 | 125.0 | 2.0 | 100.0 | 2.0 |
| | 35,112.9 | 288.6 | 35,271.7 | 285.3 | 40,199.5 | 284.3 |
| IV. Supervision of Leasing Operations, Section 18(b)(4): | | | | | | |
| Minerals Management Service | 24,191.1 | 358.3 | 25,206.2 | 358.3 | 25,437.6 | 358.3 |
| U.S. Fish and Wildlife Service | 75.0 | 1.0 | 75.0 | 1.0 | 50.0 | 1.0 |
| | 24,266.1 | 359.3 | 25,281.2 | 359.3 | 25,487.6 | 359.3 |
| V. General Administration, | | | | | | |
| Minerals Management Service | 26,024.9 | 389.9 | 28,268.2 | 386.9 | 28,277.7 | 387.1 |
| Office of the Solicitor (DOI) | 350.0 | 7.0 | 350.0 | 7.0 | 350.0 | 7.0 |
| | 26,374.9 | 396.9 | 28,618.2 | 393.9 | 28,627.7 | 394.1 |
| Total Requirements: | | | | | | |
| Minerals Management Service | $105,835.3 | 1,289.3 | $106,888.2 | 1,273.0 | $112,117.4 | 1,270.2 |
| U.S. Fish and Wildlife Service | 200.0 | 3.0 | 200.0 | 3.0 | 150.0 | 3.0 |
| Office of the Solicitor (DOI) | 350.0 | 7.0 | 350.0 | 7.0 | 350.0 | 7.0 |
| | $106,385.3 | 1,299.3 | $107,438.2 | 1,283.0 | $112,617.4 | 1,280.2 |

a/ Funding and Staffing provided in this column reflect FY 1987 appropriations to the MMS.
b/ Funding and Staffing provided in this column reflect the FY 1988 request for MMS as submitted to the Department, 1/87.



DEPARTMENT OF THE INTERIOR

Minerals Management Service

Estimated Appropriation and Staffing Requirements
Proposed Final 5-Year Leasing Program



Option A.2.g (Table 16)
(Dollars in Millions)

| Category/Section of Act | FY 1990 c/ Funds | FY 1990 c/ Staff | FY 1991 c/ Funds | FY 1991 c/ Staff | FY 1992 c/ Funds | FY 1992 c/ Staff |
|---|---|---|---|---|---|---|
| I. Resource Information, Section 18(b)(1): | | | | | | |
| Minerals Management Service | $11,007.7 | 129.2 | $6,949.0 | 121.0 | $4,686.8 | 113.7 |
| II. Exploration Data, Section 18(b)(2): | | | | | | |
| Minerals Management Service | 6,790.2 | 106.7 | 6,956.4 | 110.7 | 6,910.2 | 91.3 |
| III. Environmental Activity, Section 18(b)(3): | | | | | | |
| Minerals Management Service | 38,581.2 | 282.3 | 34,327.6 | 263.3 | 13,752.0 | 162.1 |
| U.S. Fish and Wildlife Service | 80.0 | 2.0 | 60.0 | 2.0 | 50.0 | 1.0 |
| | 38,661.2 | 284.3 | 34,387.6 | 265.3 | 13,802.0 | 163.1 |
| IV. Supervision of Leasing Operations, Section 18(b)(4): | | | | | | |
| Minerals Management Service | 25,808.6 | 359.7 | 26,431.1 | 363.3 | 26,931.1 | 365.3 |
| U.S. Fish and Wildlife Service | 40.0 | 1.0 | 35.0 | 1.0 | 25.0 | 1.0 |
| | 25,848.6 | 360.7 | 26,466.1 | 364.3 | 26,956.1 | 366.3 |
| V. General Administration, | | | | | | |
| Minerals Management Service | 28,277.8 | 387.6 | 28,725.6 | 392.8 | 28,054.6 | 381.4 |
| Office of the Solicitor (DOI) | 350.0 | 7.0 | 350.0 | 7.0 | 350.0 | 7.0 |
| | 28,627.8 | 394.6 | 29,075.6 | 399.8 | 28,404.6 | 388.4 |
| Total Requirements: | | | | | | |
| Minerals Management Service | $110,465.5 | 1,265.5 | $103,389.7 | 1,251.1 | $80,334.7 | 1,113.8 |
| U.S. Fish and Wildlife Service | 120.0 | 3.0 | 95.0 | 3.0 | 75.0 | 2.0 |
| Office of the Solicitor (DOI) | 350.0 | 7.0 | 350.0 | 7.0 | 350.0 | 7.0 |
| | $110,935.5 | 1,275.5 | $103,834.7 | 1,261.1 | $80,759.7 | 1,122.8 |

c/ Resource estimates for the prelease activities for these years only reflect workload of the PFP; no estimates are provided for work on prelease planning activities for sales which would be included in the next 5-year program.

# APPENDIX U

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SUBAREA ATTACHMENT

Areas Proposed for Deferral

from the

5-Year Outer Continental Shelf Oil and Gas Leasing Program

## Preface

### Subarea Deferrals

A Federal Register notice requesting public comments on the schedule and policies selected as the Draft Proposed Program was published on March 22, 1985 (50 FR 11585). Although public views were requested on any topic related to the 5-year program, respondents also were requested to provide comments in response to several specific topics. Among these was the following:

> Whether there are subareas within planning areas which should be subject to special considerations, either in the presale planning process for each sale or, more generally, within the 5-year program itself, and what those considerations should be.

In response, a variety of public comments suggested that various areas be deferred from the 5-year leasing program. The Secretary of the Interior reviewed these responses and other information. Based on his review, in the Proposed Program published in February 1986, the Secretary proposed 15 subareas for deferral from leasing and highlighted 13 subareas for further analysis and comment. Public comments were received on these areas and on additional areas suggested for deferral.

In order to facilitate the Secretary's review of these recommendations, the Minerals Management Service (MMS) has prepared a standarized format description of these areas for review and evaluation.

Most public comments did not provide enough information for identification of exact boundaries. In addition, closely related but not identical comments were sometimes received from different reviewers. The MMS prepared subarea descriptions which follow, therefore, necessarily represent some interpretation and recombination of various individual comments.

Further, in order to facilitate review of the very large number of subarea deferral candidates identified offshore California, smaller areas which fail totally within one or more of the composite subarea deferral recommendations prepared pursuant to Public Law 99-500 are not also described as separate individual proposals.

## Table of Contents

Table of Contents (continued)



Table of Contents (continued)

Table of Contents (continued)



Table of Contents (continued)

Planning Area: North Atlantic Planning Area

Subarea Name: Georges Bank Region (400 meter contour and submarine canyon heads)

Deferral Recommended by: Environmental Protection Agency, State of Massachusetts, Massachusetts Audubon Society, Natural Resource Defense Council, Greenpeace, Association for the Preservation of Cape Cod, League of Women Voters of Massachusetts

Geographic Description:

This candidate encompasses 1,708 blocks and covers an area of 3,935,232 hectares (9,723,958 acres). Included are Georges Bank and associated areas within the 400 m (1,312 ft) contour. This area is considered the upper continental slope and parallels the Georges Bank shelf, beginning roughly at the shelf break (approximately 200 m (656 ft) water depth). It is a relatively steep area characterized by numerous deep submarine canyons and hummocky topography with gullies and terraces cutting across the surface. This subarea ranges from approximately 76 to 282 km (47 mi to 175 mi) offshore southeastern New England.

Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

Georges Bank Region 400-meter contour:

o Studied in the following EIS's:
  Sale 52 (Sale cancelled 8/83)
  Sale 82 (Part I cancelled 9/84)--all canyon area blocks were deferred before the Final Notice of Sale

Oil and Gas Resource Potential:

Eight exploratory and two COST wells have been drilled within this area between 1976 and 1982. Two wells encountered significant gas shows although testing proved them non-commercial. The most prospective areas are located seaward of the 400 meter contour. This is especially true where reefs or thick delta sands occur within the hydrocarbon generation zone. Deeper Triassic rift basins are also considered prospective. The area becomes more prospective moving seaward from the inner bank toward the carbonate buildup along the southern edge of the bank. The most recent geophysical exploration activity in this subarea occurred in 1984.



Georges Bank Region (400 meter contour and submarine canyon heads) (Continued)

In the southern part of the subarea, data coverage is sufficient to define specific prospects and, locally, specific plays within prospects. Data coverage in the northern part is sufficient to identify major trends associated with Triassic rift-basins and associated structures and stratigraphic traps.

The Jurassic/Cretaceous paleo-shelf edge complex, considered a potential exploration trend, contains both structural and stratigraphic traps and occurs just seaward of the southern boundary of the subarea.

The southern part of the subarea is from moderate to high potential, but, the northern part appears to be of low potential. Some of the rift-basin structures have been of interest to industry and, although very risky, may contain significant resources.

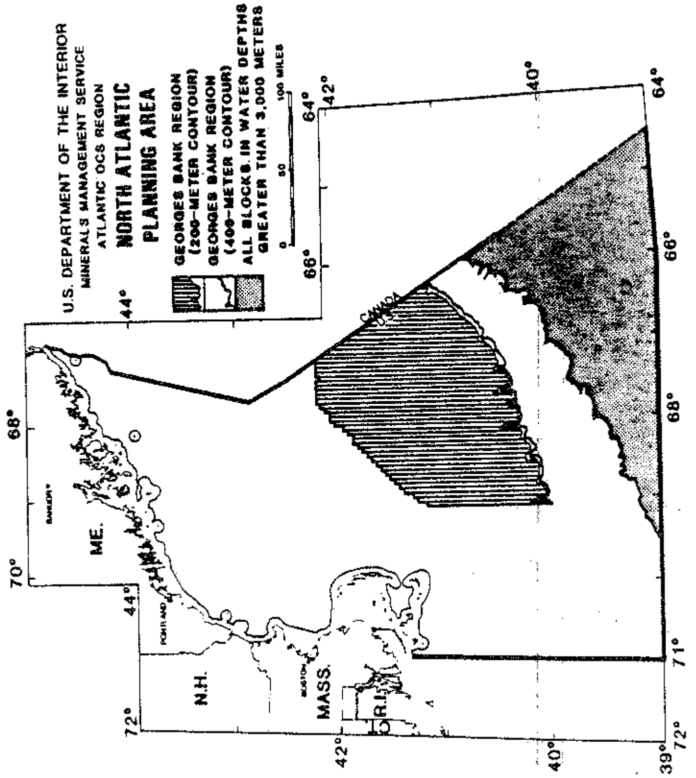
Description of the Environment:

The Georges Bank continental slope is a steep, narrow area paralleling the shelf and extending from the shelf break to depths of about 2,000 m (6,560 ft). The slope surface exhibits a varied topography with surface deposits consisting of fine-grained silt and clay. Submarine canyons incise the slope shoreward. Canyon walls tend to exhibit numerous exposures of outcrops as well as steep talus slopes. Although the silt/clay biotype has a low productivity associated with it, the area is known to support significant populations of groundfish and lobsters with highest concentrations in the canyon heads. Megafaunal abundances are generally higher in the canyon than on the slope at similar depths. Dense localized populations of corals, sponges, and shrimp contribute to the higher megafaunal numbers.

Potential Impacts Avoided by Deletion of this Subarea:

Localized water quality impacts would be reduced. The likelihood of oil and gas related contaminants being entrained and circulated within the Georges Bank gyre would be reduced. Impacts from routine discharges (muds and cuttings, formation water, sanitary/domestic wastes) would remain localized and low. On a regional basis, deletion of this area would not significantly reduce impacts on water quality.

Georges Bank and the canyon areas support a large fixed gear and trawling industry. The current flow and transportation of sediments within the canyon axis varies for each canyon. Deletion of this subarea would eliminate potential moderate impacts from mechanical activities, possible drilling fluid dispersement within canyons, and local spills near heavily fished areas.






Planning Area: North Atlantic Planning Area

Subarea Name: Gulf of Maine (North of 42° 30')

Deferral Recommended by: Environmental Protection Agency, National Oceanic and Atmospheric Administration, Murphy Oil USA, Audubon Society State of Maine, State of Massachusetts

Geographic Description:

This subarea deletion candidate encompasses 1,813 blocks and covers an area of 4,176,926 hectares (10,321,409 acres). The Gulf of Maine is an area of extremely thin sediments, lying east of Massachusetts, New Hampshire, and Maine. It extends from the nearshore State waters seaward along and north of 42° 30' north latitude.

Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

Gulf of Maine:

- o Not studied as an alternative at the EIS stage
- o Area never offered

Oil and Gas Resource Potential:

No wells have been drilled in this subarea, and the most recent geophysical exploration activity occurred in 1984. This area is underlain by numerous Triassic rift-basins. Present information on the occurrence and distribution of these basins is based primarily on literature studies. Insufficient data exist in this subarea to properly identify and evaluate structural and stratigraphic traps, and thus, oil and gas potential is unknown.

Description of the Environment:

The State territorial waters of Maine, New Hampshire and northern Massachusetts form the western boundary of this subarea deletion candidate. This is a high-energy coastline, composed predominantly of rocky headlands. The exposed rocky shore supports a dense and diverse assemblage of invertebrates which are an important food source for a variety of seabirds. A jet-like current in the Georges Bank area forms a quasi-permanent boundary between the Gulf and the Bank. High concentrations of commercial macrobenthic organisms and groundfish are found on the fringes of the area. Fishes of the Gulf of Maine demonstrate limited movement into adjacent waters. Most stocks are nearly or fully exploited. The endangered humpback and right whales are known to migrate into (spring) and exit (fall) the Gulf of Maine and more northern waters. The endangered leatherback turtle has been observed feeding in the Gulf in June and in more northern waters throughout the summer. The coastline from northern Massachusetts, New Hampshire, and Maine provides extensive recreational opportunity and supports a healthy tourism industry.

Gulf of Maine (North of 42° 30') (Continued)

Potential Impacts Avoided by Deletion of this Subarea:

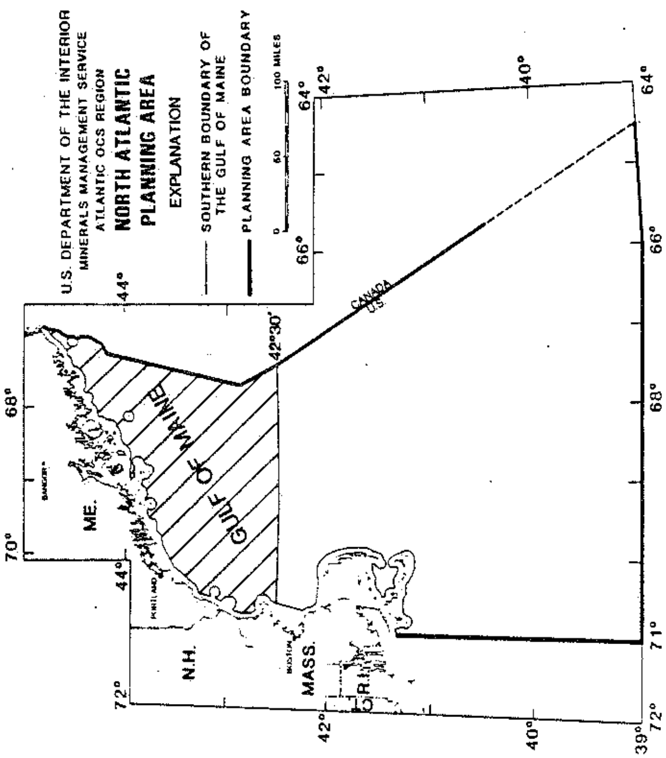
This subarea deletion would eliminate any potential for onshore visual impacts to coastal Maine, New Hampshire, and northern Massachusetts resulting from offshore drilling facilities. The risk of impacts to coastal recreation areas from platform spills would also be substantially reduced.

The extent of this deletion would also reduce the likelihood of land-use impacts from onshore facilities in Maine, New Hampshire, or Massachusetts. Such facilities would likely be located elsewhere in the region.

Overall, the water quality impact would not be significantly reduced. However, the potential of high impact to limited coastline, and especially embayment areas, would be reduced to a low level. The potential for rapid transport of oil and gas related contaminants to the coast or towards the Bay of Fundy by the Gulf of Maine circulation would be virtually eliminated.

Deletion of this subarea would further decrease the expected low impact on sea birds. A deletion would reduce local impacts from rig placements and oil spills on benthos, fish, and whales.





Planning Area: North Atlantic Planning Area

Subarea Name: North of 40° 15' North Latitude

Deferral Recommended by: State of New York

Geographic Description:

This candidate encompasses 3,837 blocks and covers an area of 8,840,448 hectares (21,844,747 acres). From the U.S./Canadian Boundary this area extends eastward along 40° 15' north latitude to the planning area boundary and encompasses Georges Bank and the Gulf of Maine, all previously described.

Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

North of 40° 15':

- o Not studied as an alternative at the EIS stage
- o Offered and 63 leases issued in Sale 42 (December 18, 1979)

Oil and Gas Resource Potential:

Eight exploratory and two COST wells have been drilled within this area between 1976 and 1982. Two wells encountered significant gas shows although testing proved them non-commercial. The section deeper than 3,963 m (13,000 ft) is the most prospective. This is especially true where reefs or thick delta sands occur within the hydrocarbon generation zone. Deeper Triassic riftbasins are also considered prospective. The most recent geophysical exploration activity occurred in 1984.

The subarea is mostly confined to the continental shelf except for the southeast corner where slope and deep-water upper-rise acreage is included. The western part of the area contains a number of large Triassic rift-basins and a few structural traps. In the southern part of the subarea, data coverage is sufficient to define specific plays within prospects. Data coverage in the northern part is sufficient to identify major trends associated with Triassic rift-basins, associated structures, and stratigraphic traps.

A large segment of the Mesozoic paleo-shelf edge complex (a possible exploration trend consisting of structural and stratigraphic traps) occurs entirely within the subarea (southeastern part). A few isolated structures, also present in the southeastern part of the subarea, may be related to salt diapirism.

High potential acreage in this subarea is located in the southeastern part. Elsewhere, except for the Gulf of Maine where the oil and gas potential is unknown, the acreage is not as prospective.



North of 40° 15' North Latitude (Continued)

Description of the Environment:

This subarea is a composite of previously described areas. North Atlantic fishing grounds, suspected feeding areas, and migratory routes for the endangered right whales, humpback whales, and leatherback turtles would be deleted.

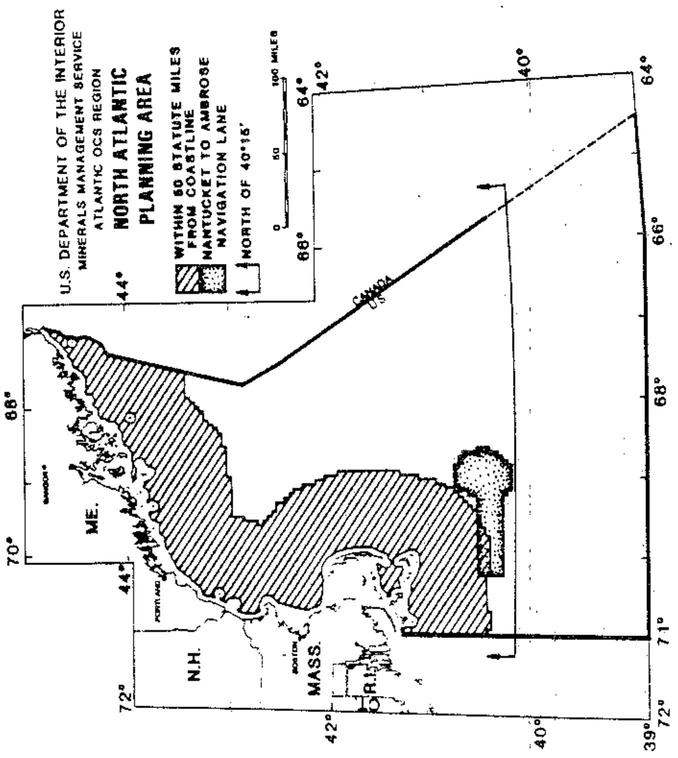
Potential Impacts Avoided by Deletion of this Subarea:

This subarea deletion would eliminate any potential for onshore visual impacts resulting from offshore drilling facilities to coastal Maine, New Hampshire, and Massachusetts. The risk of impacts to coastal recreation areas from platform spills would also be substantially reduced.

This deletion would also reduce the likelihood of land use impacts from onshore facilities in Maine, New Hampshire or Massachusetts. Such facilities would likely be located elsewhere in the region.

The overall water quality impact would not be significantly reduced. Potentially high local impacts to coastlines and embayments would be reduced to a low level.

All local impacts to the fauna would be entirely avoided and regional impacts, already estimated to be low, would be reduced to non-existent.






Planning Area: North Atlantic Planning Area

Subarea Name: North Atlantic Planning Area Portion of the Nantucket to Ambrose Navigation Lane and Precautionary Area

Deferral Recommended by: State of New York

Geographic Description:

This candidate encompasses 226 blocks and covers an area of 520,704 hectares (1,286,659 acres). This area lies south-southeast of Nantucket Island in water depths between approximately 60 and 100 m (197 and 328 ft). It lies between 128 and 249 km (80 and 155 mi) from southern New England.

Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

Nantucket to Ambrose Navigation Lane:

- o Studied in Sale 82 EIS
- o Deferred from Sale 82 Part I to Sale 82 Part II (82 Part II cancelled 12/31/84)

Oil and Gas Resource Potential:

No wells have been drilled in this subarea and the most recent geophysical exploration activity occurred in 1983.

This subarea contains large Triassic rift-basins and associated stratigraphic traps. A few structures do occur, notably in the eastern part of the subarea.

Data coverage is sufficient to delineate specific prospects and regional trends.

Since the subarea is largely underlain by high-risk Triassic rift-basins and a few structural traps, it is not considered as prospective as similar continental shelf acreage that lies to the east of the subarea. However, within the subarea, prospectiveness is shown to increase toward the eastern and southeastern parts.

Description of the Environment:

This navigation lane/USCG Precautionary Area consists of the southern extremes of Nantucket Shoals, Great South Channel and southern portions of Georges Bank. The waters are considered to contain nutrient rich upwellings supporting sport and commercial fishing industries. Various populations of sea ducks are known to winter in the shoals. The endangered humpback whale has been sighted along the 100 m contour from May to November.

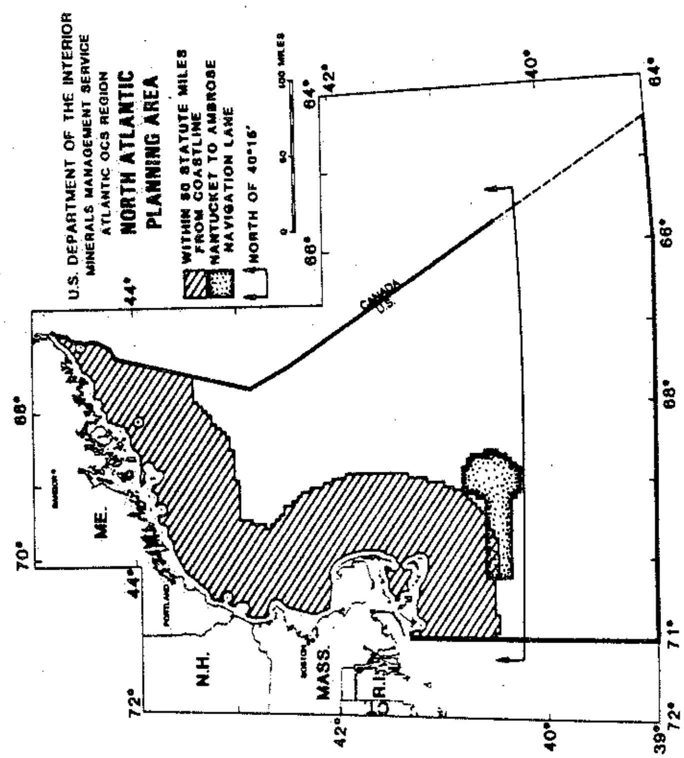
North Atlantic Planning Area Portion of the Nantucket to Ambrose Navigation Lane and Precautionary Area (Continued)

Potential Impacts Avoided by Deletion of this Subarea:

Water quality impacts would remain unchanged.

Deletion of this area would provide local protection for a number of biological, recreational and economic resources or protected species by removing any potential platforms or oil spills within the area. The deletion, however, would not reduce the expected low regional impact.





Planning Area: North Atlantic Planning Area

Subarea Name: All Blocks in Water Depths greater than 3,000 meters (North Atlantic)

Deferral Recommended by: Chevron

Geographic Description:

This candidate encompasses 1,756 blocks and covers an area of 4,045,824 hectares (9,997,231 acres). These blocks lie in the southeastern corner of the planning area in water depths as great as 4,500 m (14,760 ft), and are approximately 306 to 563 km (190 to 350 mi) from the coast of southeastern New England.

Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

Blocks in water depths greater than 3,000 meters, North Atlantic:

- o Not studied as an alternative at the EIS stage
- o Offered in Sale 82 (Part I cancelled 9/84)

Oil and Gas Resource Potential:

No wells have been drilled in this subarea and the most recent geophysical exploration activity occurred in 1982.

This subarea is restricted to deep water acreage of the continental rise. Except for a few widely spaced seismic lines, data coverage is sparse to essentially non-existent within this area. Therefore, oil and gas potential is unknown.

Description of the Environment:

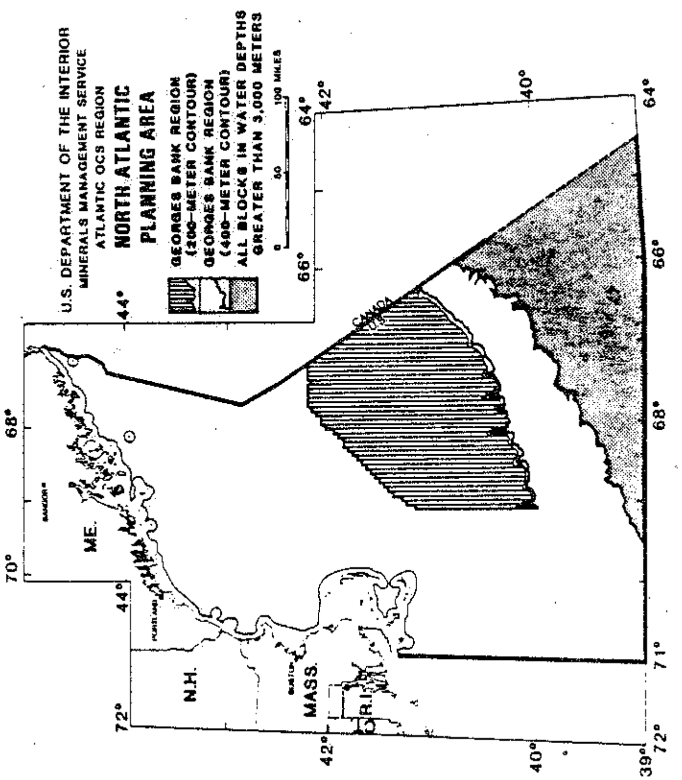
Studies have demonstrated a decrease in faunal density with depth and distance from shore. Polychaeta and Crustacea have the highest densities with polychaetes decreasing with distance from the continental shelf as crustaceans increase. Deep-water fish are primarily rattails, brotulid fish and species of deep-sea sharks. It is not an area of commercial fishing.

Potential Impacts Avoided by deletion of this area:

No substantial change in impact to water quality would occur.

Possible impacts in this area because of OCS activities would be limited primarily to the benthos. With an approximate density of 65 animals/$m^2$ possible local impacts would be low. Deletion of this area would provide little to no avoidance of regional or local impacts.





Planning Area: North Atlantic Planning Area

Subarea Name: North Atlantic Congressional Moratorium including Canyon Areas

Deferral Recommended by: Action of U.S. Congress

Geographic Description:

This candidate encompasses 2,240 blocks and covers an area of 5,160,681 hectares (12,752,320 acres). It consists of the U.S. portion of the Georges Bank, roughly defined by the 42° N latitude on the north, the 60 m (197 ft) isobath on the southwest and east and by the U.S./Canada International Boundary on the northeast. Included in this deferral option are areas lying at the head of, or, within the submarine canyons, including Atlantis, Veatch, Hydrographer, Welker, Gilbert, Oceanographer, Lydonia, Alvin, Powell, Nygren, and Munson Canyons. This subarea is defined in detail in Public Law 99-190.

Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

North Atlantic Congressional Moratorium and Canyon Area:

- o Entire area deferred from Sale 82 (Part 1, Cancelled 9/84)
- o Portions of this area were studied in the Sale 82 EIS

Oil and Gas Resource Potential:

The COST G-1 was drilled in this area in 1976 to a depth of 4,900 m (16,071 ft). Intentionally drilled off structure, the test did not encounter hydrocarbon shows and indicated little promise for the deeper Jurassic section. Generally, the sedimentary section has low porosity and contains poor source rocks. The most recent geophysical exploration activity in this subarea occurred in 1984.

The subarea includes the northern two-thirds of the Georges Bank proper extending slightly into the Gulf of Maine and the canyon areas. The sedimentary section in the Georges Bank proper, up to 7,621 m (25,000 ft) thick, includes the northern part of Georges Bank Basin. Triassic rift-basins (some of which may contain over 3,963 m (13,000 ft) of sediment), and anticlinal structural traps occur within the area. A few structures identified in the northeastern part of the area straddle the U.S.-Canadian boundary line. Underlying the submarine canyons, where the sedimentary section may be as much as 10,668 m (35,000 ft) thick, is the Jurassic-Cretaceous paleo-shelf edge complex of structural and stratigraphic traps.



North Atlantic Congressional Moratorium and Canyon Areas (Continued)

In the northwestern third of the subarea, data coverage is insufficient to evaluate the hydrocarbon potential. Data coverage in the remaining part of the subarea, including the canyons, is sufficient to define specific prospects and, locally, specific plays within prospects. On the shelf, hydrocarbon potential grades from low in the northwest to moderate in the southwest. The most prospective acreage, an area of high potential, underlies the submarine canyons.

Description of the Environment:

The Congressional moratorium subarea includes all of the highly productive Georges Bank area which provides a valuable habitat for many commercially, recreationally, and ecologically important fish species. In addition, the moratorium subarea includes the Great South Channel which has been demonstrated to be an important feeding area for the endangered right whale during the spring migration. The area inshore from the Great South Channel to approximately 71° longitude or Massachusetts territorial waters, supports part of the valuable shallow-water fisheries of the north Atlantic, such as lobster and sea scallops.

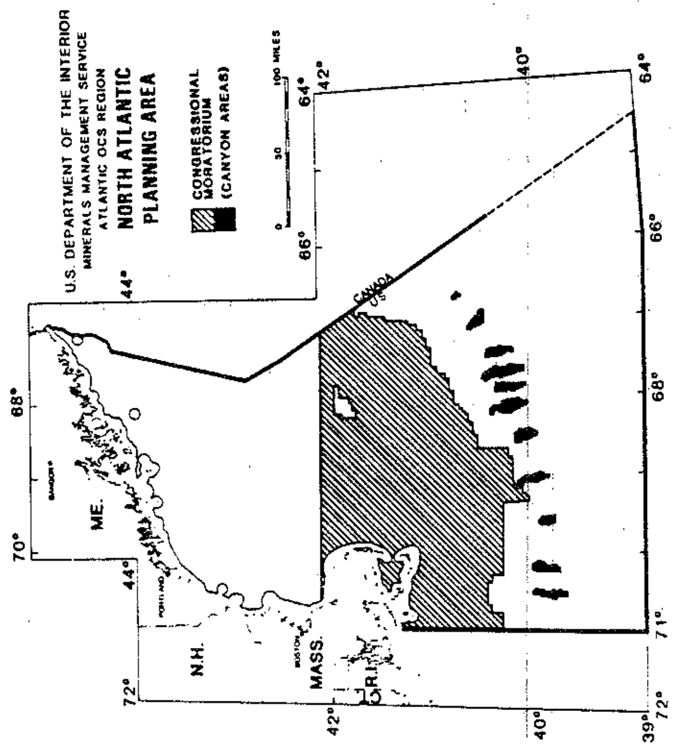
Other species of concern which may be found in the deferred area include the endangered leatherback turtle, which uses the area for feeding and as a migration route northward during the summer, and the threatened loggerhead turtle, which is occasionally found in the shallower parts of this deferral area. The submarine canyons included under this deferral are generally areas of increased productivity in comparison to the adjacent slope areas. The submarine canyons are known to support appreciable populations of lobsters and other invertebrates and benthic and pelagic fish species.

Potential Impacts Avoided by Deletion of this Subarea:

Deferral of this subarea would eliminate potential local impacts to the canyon areas resulting from direct drilling discharges and mechanical damage. The possibility of onshore visual impacts resulting from the placement of drilling structures would be eliminated. Deferral of this subarea will substantially decrease the potential for impacts to the coastline adjacent to the subarea which is an important breeding area for several avian species of concern, such as the bald eagle and Arctic peregrine falcon. Selection of this subarea deferral would reduce the potential impacts to fishery resources on Georges Bank by removing the risk of local platform spills from the area. Overall, in a regional scope, the deferral of this subarea would reduce potential impacts from low to negligible.

This deferral would reduce the risk of oil and gas related contaminants being directly incorporated into the Georges Bank gyre, and the canyon and canyon head areas, thus reducing local impact on water quality.

The regional impact on water quality would not be significantly reduced.






Planning Area: North Atlantic Planning Area

- Subarea Name: Within 50 Statute Miles from Coastline (Maine to Massachusetts)

Deferral Recommended by: Massachusetts Audubon Society, State of New York, Natural Resources Defense Council, Greenpeace

Geographic Description:

This candidate encompasses 2,612 blocks and covers an area of 6,017,722 hectares (14,870,116 acres). This area would include all the blocks on the continental shelf that lie within 80 km (50 mi) of the Maine, New Hampshire, and Massachusetts coasts.

Sales (and date held) for which the Subarea was Studied and Disposition In Each Sale:

Within 50 statute miles from coastline within north Atlantic:

- o Studied as an alternative in Sale 82 EIS
- o Entire area deferred from Sale 82 (Part 1, Cancelled 9/84)

Oil and Gas Resource Potential:

No wells have been drilled in this subarea where the most recent geophysical exploration activity occurred in 1983. This subarea includes the western half of the Gulf of Maine and the inner shelf area along the coast of Massachusetts. Generally, the sedimentary section is thin with some localized thickening as a result of Triassic rift-basin formation. In the Gulf of Maine, the section of only a few hundred feet may thicken to as much as a few thousand feet within the rift-basins. Sufficient data does not exist to definitively evaluate hydrocarbon potential of this area. South of Cape Cod the section thickens to as much as 5,488 m (18,000 ft) in riftbasin areas. This subarea, an area of sufficient data coverage and known rift-basin development, is of low hydrocarbon potential.

Description of the Environment:

The area enclosed by this deferral alternative is typically an area of medium-grained sand and in water depths of less than 100 m (328 ft).

Although some fisheries activities are present in the deferral area, most landings in the New England region are farther offshore or within the State territorial waters. The endangered right whale may be present during the spring in the southern section of this deferral area, near the Great South Channel. The threatened loggerhead sea turtle is occasionally present in the nearer-to-shore section of this subarea, and the endangered leatherback turtle is reported to use the more eastern part of this subarea as part of their migration route. Many coastal avian species are present in this subarea, with elevated numbers during the spring, summer, and fall seasons.

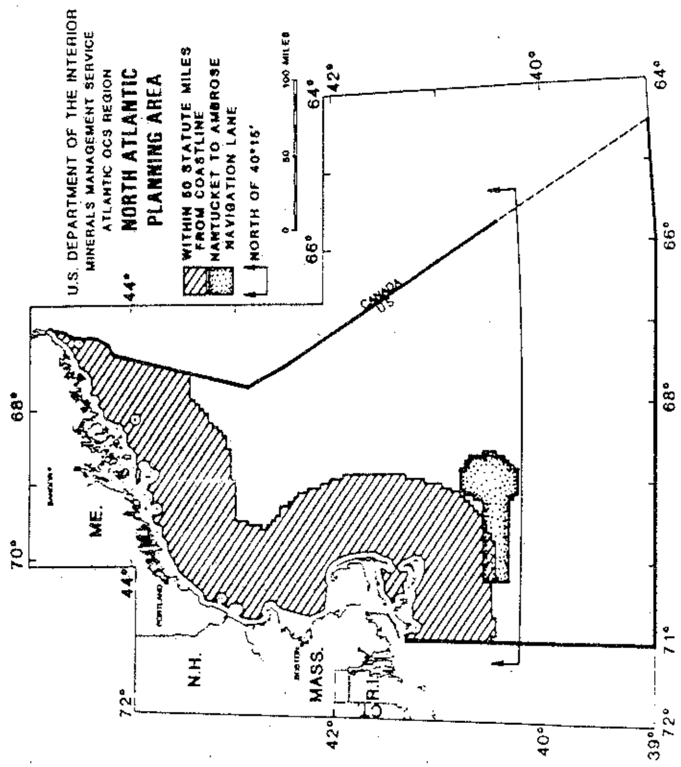
Within 50 Statute Miles from Coastline (Continued)

Potential Impacts Avoided by Deletion of this Subarea:

The potential regional impacts on endangered or threatened whales, turtles, and birds would remain unchanged from the proposed action if this alternative is selected. However, some impacts to these species within the deferred area would be reduced. No reduction in the estimated potential impacts on fisheries and air quality is expected under this alternative. Deferral of this subarea would eliminate the possible onshore visual impacts which may result from the placement of drilling structures in the subarea.

The regional impact on water quality would not be significantly reduced by the deferral of this area. On a local scale, however, the risk of oil and gas related contaminants being directly incorporated into the Georges Bank gyre would be reduced.





Planning Area: North Atlantic Planning Area

Subarea Name: Nearshore/Low Potential Block Deferral

Deferral Recommended by: Environmental Protection Agency, Murphy Oil USA, Natural Resources Defense Council

Geographic Description:

This candidate encompasses 3,212 blocks and covers an area of 6,911,488 hectares (17,275,967 acres). It consists of the area shoreward of a line that runs northeast-southwest from 129 km (80 mi) south of Martha's Vineyard to 275 km (171 mi) east of the tip of Cape Cod. Major features included in this area are the Gulf of Maine, Nantucket Sound, and Nantucket Shoals.

Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

Nearshore Block Deferral:

- o Not studied as an alternative at the EIS stage
- o Area never offered

Oil and Gas Resource Potential:

No wells have been drilled in this subarea where the most recent geophysical exploration activity occurred in 1983. This subarea includes the Gulf of Maine and the inner shelf area along the southern coast of Massachusetts. Generally, the sedimentary section is thin with some localized thickening as a result of Triassic rift-basin formation. The section in the Gulf of Maine of only a few hundred feet may thicken to as much as a few thousand feet in the rift-basins. Sufficient data does not exist to definitively evaluate hydrocarbon potential of this area. The southernmost part of the area south of Cape Cod, an area of sufficient data coverage and known rift-basin development, is of low hydrocarbon potential.

Description of the Environment:

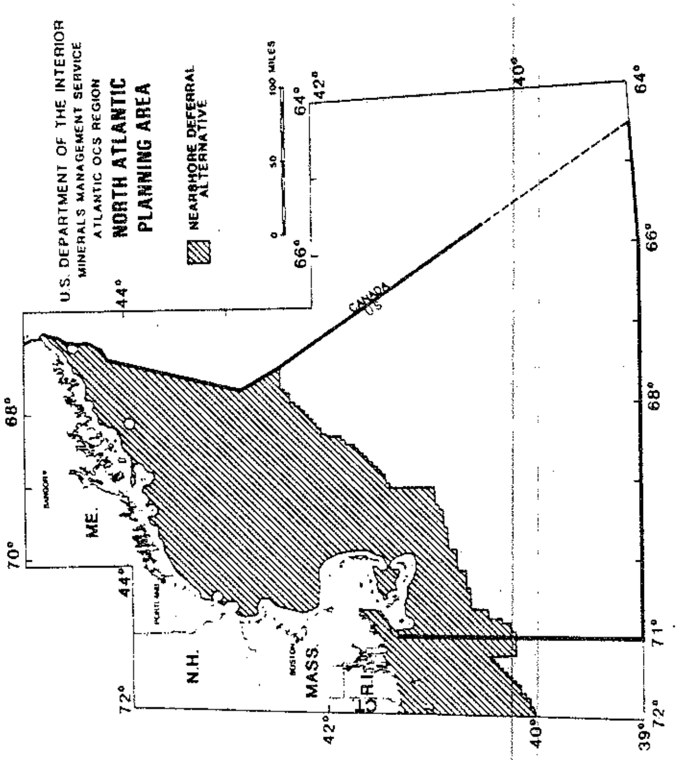
The Nearshore deferral area in the North Atlantic Planning Area consists of medium-grained sand sediment which grades to fine-grained sand farther offshore. The deferral alternative is in water depths of generally less than 100 m (328 ft), except in the Gulf of Maine, and receives moderate energy input from the hydrodynamic regime of the area. The fisheries in this area are productive and provide an appreciable amount of the total landings in the New England region. The endangered right whale is reported to use the area southeast of Nantucket Island for feeding and the endangered leatherback and threatened loggerhead turtles use portions of the area during the late spring through early fall months. Many avian species are in this area throughout the year, but can be found in increased numbers during the spring and fall migrations.



Nearshore Block Deferral (Continued)

Potential Impacts Avoided by Deletion of this Subarea:

Deferral of this subarea would eliminate any potential onshore visual impacts on the states of Maine, New Hampshire, and Massachusetts resulting from offshore drilling structures. The risk of impacts to coastal recreation areas would not be significantly reduced. Because the resource potential of the North Atlantic Planning Area will not be substantially reduced if this alternative is selected, overall impacts on endangered and threatened birds, turtles, and cetaceans would not be reduced. Additionally, the potential impacts on fisheries, water quality, air quality, and the benthic environment would be unchanged.






Planning Area: Mid-Atlantic Planning Area

Subarea Name: Major Shipping Lanes (Sale 111, Visual No. 5)

Deferral Recommended by: State of New Jersey

Geographic Description:

This candidate encompasses 286 blocks and covers an area of 658,924 hectares (1,628,238 acres). The major shipping lanes within the mid-Atlantic include Traffic Separation Schemes (TSS's) established by the U.S. Coast Guard. These are: a TSS lying south of Rhode Island controlling access into Narragansett and Buzzards Bay, a TSS lying southeast of New York City controlling access into Raritan Bay, a TSS controlling access to Delaware Bay just south of Cape May, New Jersey, and a small TSS north of Virginia Beach controlling access into the Chesapeake Bay.

Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

Major shipping lanes (TSS):

° Not studied as an alternative at the EIS stage
° Deferred by 80 km (50 mi) deletion--Sale 111 Area Identification

Oil and Gas Resource Potential:

Triassic rift-basins occur within this subarea, however, no structural or stratigraphic traps have yet been identified. Data coverage is essentially non-existent, which precludes the identification of structural and stratigraphic traps.

Possible exploration trends associated with this subarea cannot be identified given the lack of data. Petroleum potential is unknown in areas lacking data; however, the northernmost part of the subarea is thought to be more prospective than the southernmost parts of the subarea because of basement related structures.

To date, no wells have been drilled within the subarea, and the latest geophysical exploration activity occurred in 1976.

Description of the Environment:

The coastal areas in which these subareas are located are typically higher in phytoplankton and zooplankton biomass than the rest of the shelf. The New York Bight section of this deletion candidate is reported to have high bacterial counts, the most contaminated sediment, and the most acute and extensive alterations of the benthic ecosystems. No noticeable difference from other near-coastal areas has been noted for the Delaware Bay and Chesapeake Bay areas. The areas in this subarea deletion candidate would contain extremely large numbers of anadromous fish species (e.g., striped bass, shad, alewife) and species

Major Shipping lanes (Sale III, Visual No. 5) (Continued)

which use the estuaries as nursery or feeding areas (e.g., menhaden, bluefish, spot) during the spring and fall migrations. Numerous shore, marine, coastal, and waterfowl species--including the endangered peregrine falcon--occur in these areas.

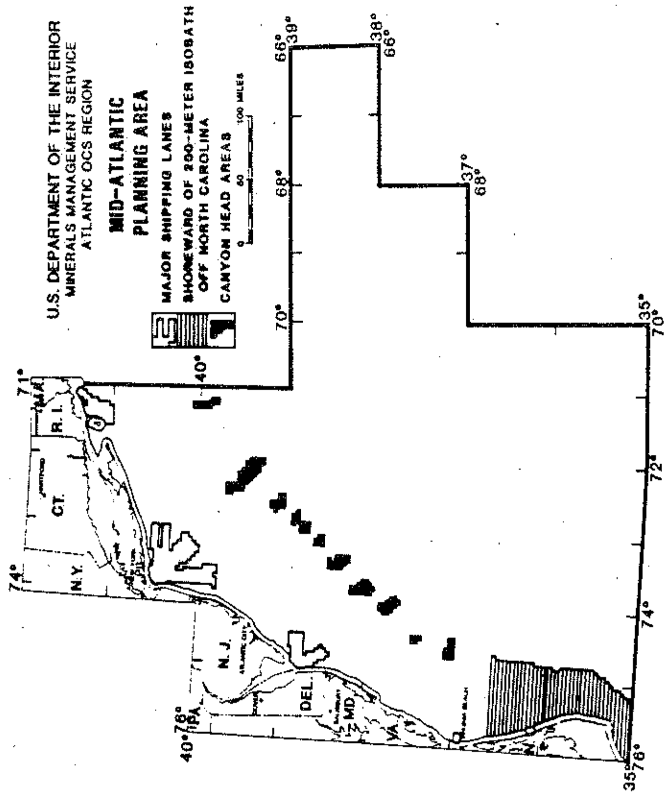
Potential Impacts Avoided by Deletion of this Subarea:

This subarea deletion would reduce the potential for onshore visual impacts to portions of the coasts of Rhode Island, New Jersey, eastern Long Island, and Delaware resulting from offshore drilling facilities. The risk of impacts to coastal recreation areas from platform spills would also be reduced.

Water quality impact levels would not change.

Selection of this deletion candidate would greatly decrease the potential impacts to the fauna that use the area as a migration route. The potentially major impacts to the proximate estuarine systems would be appreciably reduced and the probability of vessel accidents in the area caused by OCS activities would be removed.





Planning Area: Mid-Atlantic Planning Area

Subarea Name: Shoreward of the 200-meter Isobath off North Carolina

Deferral Recommended by: State of North Carolina, City of Wilmington

Geographic Description:

This candidate encompasses 557 blocks and covers an area of 1,283,328 hectares (3,171,103 acres). This area includes all blocks off North Carolina extending from the state territorial water boundary out to the 200-m (656-ft) contour, approximately 56 km (35 mi) from shore.

Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

Shoreward of 200 meters (North Carolina):

° Not studied as an alternative at the EIS stage
° Deferred--Sale 111 Area Identification
° Active Leases (11)

Oil and Gas Resource Potential:

Triassic rift-basins occur within this subarea and are part of the same trend of rift-basins noted elsewhere along the near-shore zone of the Planning Area. Along the eastern edge, the subarea flanks the paleo-shelf edge carbonate buildup described earlier and locally includes some structural traps. This area also includes parts of the Carolina Trough sedimentary basin, an area of thick sediment accumulation.

Data coverage within the subarea is virtually non-existent over most of the nearshore acreage, although it is sufficient in the centralmost parts to fairly well define specific prospects. Along the eastern parts coverage is fair to good, and sufficient to determine specific prospects and plays as well as stratigraphic and structural trends.

The eastern third of the subarea has high potential. The eastern-most parts are very prospective because of a local inclusion of the potential exploration trend associated with the paleo-shelf-edge carbonate complex. Elsewhere, the acreages within the subarea are considered not as prospective and, thus, of moderate to low potential. A few nearshore areas have no data at all, thus hydrocarbon potential cannot be determined.

No industry exploration wells have been drilled within the subarea and the most recent geophysical exploration activity by industry occurred in 1983.



Shoreward of the 200-meter Isobath off North Carolina (Continued)

Description of the Environment:

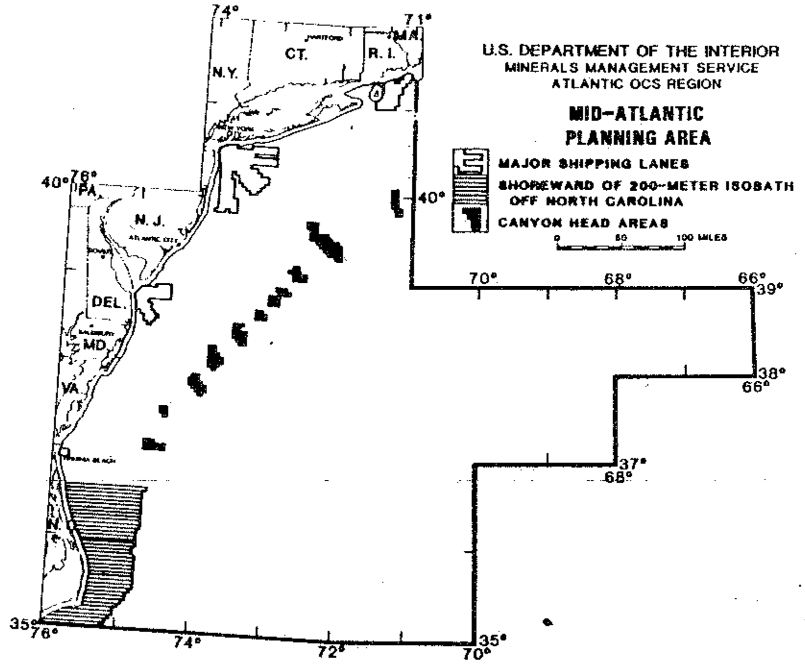
This subarea includes a major Atlantic faunal transition zone, which is located approximately at Cape Hatteras and is an area of delineation between northern boreal and southern temperate fauna. This subarea is generally a high-energy one in which the Gulf Stream dominates the southern part but decreases in influence towards the north. Many fish species including menhaden, croaker, spot, and bluefish migrate through this area during the spring and fall and are found in great numbers at these times. Because of the medium to high energy environment in this subarea, the infaunal species are predominated by filter and suspension feeders (typically polychaetes and mollusks). Most of the individuals of the five threatened or endangered turtle species that occur in the mid-Atlantic (Atlantic ridley, loggerhead, hawksbill, leatherback, and green sea turtles) migrate through this area during spring and fall. Endangered cetaceans (humpback and right whales) which migrate seasonally to the south Atlantic probably traverse this subarea.

Potential Impacts Avoided by Deletion of this Subarea:

This subarea deletion would remove virtually all of the potential for onshore visual impacts to coastal North Carolina resulting from off-shore drilling facilities. The risk of impacts to coastal recreation areas from platform spills would also be reduced.

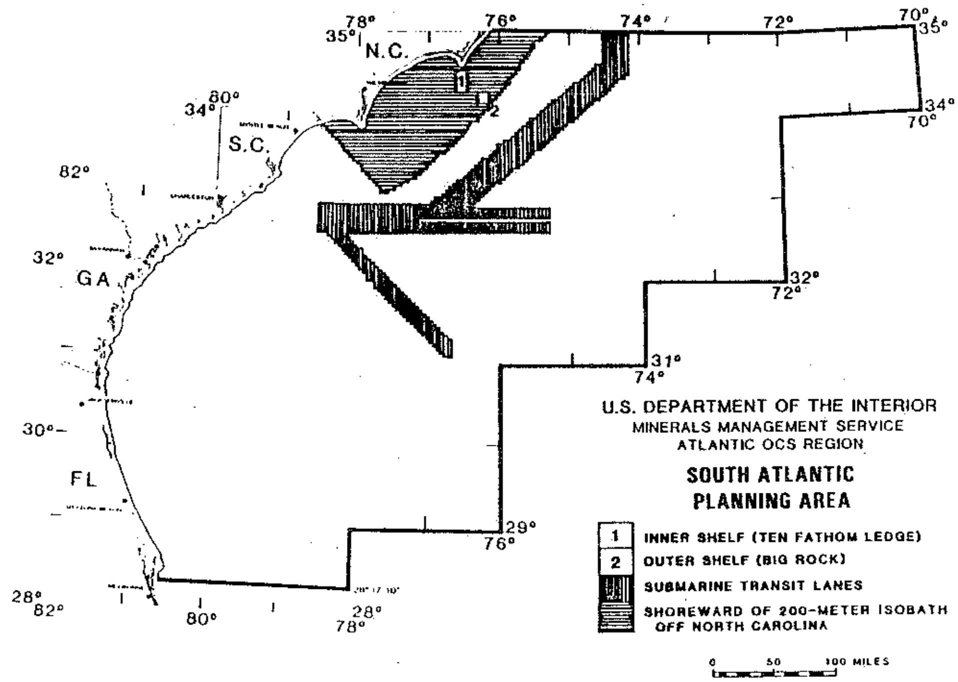
Overall impacts to water quality would not change significantly.

Deletion of this subarea could appreciably reduce the impacts to species that migrate to the south Atlantic region. Because of the relatively high energy of most of the subarea, impacts resulting from the discharge of drilling muds and cuttings and formation waters would be minimal. However, Gulf Stream filaments, or frontal eddies, may entrain and transport an accidental oil spill close to shore or maintain it in the area where it could sublethally or lethally affect, modify the routes of, or reduce the prey of the various migrating species as they pass through the area. Selection of this subarea deferral candidate would substantially reduce the probability of impacts to coastal North Carolina.



U.S. DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE
ATLANTIC OCS REGION
MID-ATLANTIC
PLANNING AREA
MAJOR SHIPPING LANES
SHOREWARD OF 200-METER ISOBATH OFF NORTH CAROLINA
CANYON HEAD AREAS
0 50 100 MILES
N.Y.
CT.
R.I.
MA.
PA.
N.J.
DEL.
MD.
VA.
N.C.
74°
71°
40°
76°
70°
68°
66°
39°
38°
37°
35°
72°


29



U.S. DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE
ATLANTIC OCS REGION
SOUTH ATLANTIC
PLANNING AREA
1 INNER SHELF (TEN FATHOM LEDGE)
2 OUTER SHELF (BIG ROCK)
SUBMARINE TRANSIT LANES
SHOREWARD OF 200-METER ISOBATH OFF NORTH CAROLINA
0 50 100 MILES
N.C.
S.C.
GA
FL
78°
76°
74°
72°
70°
35°
34°
80°
82°
32°
31°
30°
29°
28°


30

Planning Area: Mid-Atlantic Planning Area

Subarea Name: Submarine Lanes, Ocean Disposal Sites (Sale 111 FEIS)

Deferral Recommended by: State of North Carolina

Geographic Description:

This candidate encompasses 1,066 blocks and covers an area of 2,456,064 hectares (6,068,934 acres). Two major submarine transit lanes exist within the Mid-Atlantic Planning Area. One lies southeast of the tip of Long Island, approximately 24 km (15 mi) away and extending due south into about 3,000 m (9,840 ft) water depth. A small portion of another transit lane lies due east of the southernmost portion of the previously mentioned transit lane. Another submarine transit lane lies due east of Virginia Beach, beginning approximately 104 km (65 mi) from shore and extending outward to the east-northeast, and south into deeper waters.

There are presently several active ocean disposal sites. Active sites for acid waste, cellar dirt, sewage sludge (being phased-out), and wood incineration exist within the New York Bight, southeast of New York City. Other active disposal sites are: the Deepwater Municipal Sludge Site located approximately 222 km (138 mi) southeast of Ambrose Light and 212 km (132 mi) from Atlantic City in water depths ranging from 2,250 to 2,750 m (7,380 to 9,020 ft), and the Deepwater Industrial Waste Site located 231 km (144 mi) southeast of Ambrose Light and 193 km (120 mi) from Atlantic City in water depths ranging from 2,250 to 2,750 m (7,380 to 9,020 ft).

Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

Submarine Transit Lanes and Ocean Disposal Sites (Sale 111 FEIS):

- Not studied as an alternative at the EIS stage
- Protions of submarine transit lanes deferred--Sale 111 Area Identification
- Ocean disposal sites offered in Sale 76

Oil and Gas Resource Potential:

The shallow-water ocean disposal sites are located where Triassic rift-basins appear to be present within the subarea. The deep-water disposal sites are positioned seaward of the Jurassic/Cretaceous paleo-shelf-edge exploration trend.

The submarine transit-lane corridor located in the northernmost part of the planning area cuts across the Jurassic/Cretaceous paleo-shelf-edge carbonate buildup as well as contiguous trends of structural and stratigraphic trapping. The submarine transit-



Submarine Lanes, Ocean Disposal Sites (Sale 111 FEIS) (Continued)

lane corridors located in the central and southern parts of the planning area also transect, although locally, the same carbonate buildup, stratigraphic, and structural trends noted in the north. In addition, these southern corridors occur at or near the axis of the Baltimore Canyon Trough where total sediment thickness may approach 15,244 m (50,000 ft).

Data coverage with regard to ocean disposal sites is essentially non-existent and further offshore, coverage is restricted to widely-spaced USGS lines. Overall, the paucity of data within the ocean disposal sites presently precludes identification of additional structures and/or stratigraphic traps as well as potential exploration or discovery trends. The oil and gas potential of the ocean disposal sites within this subarea is, at present, considered low and where no data exists, unknown.

Data coverage in the northernmost submarine transit-lane corridor is sufficient in the northern part (shelf acreage) to define specific prospects and in the central part (continental shelf, slope, and rise acreage) to delineate specific prospects, plays, and trends. However, in the southern part (rise acreage) data coverage is sparse to non-existent. Data coverage in the southernmost submarine transit lane corridors is largely non-existent except along the landwardmost edge where coverage is sufficient to define specific prospects, plays, and trends.

Within this subarea, prospective acreages are restricted to the central part of the northern submarine corridor and to the northwesternmost parts of the southern submarine corridors. Elsewhere, the oil and gas potential is largely unknown because of a lack of data.

To date, no exploration wells have been drilled within the area of this deletion candidate and the latest geophysical exploration activity occurred in 1983.

Description of the Environment:

The submarine transit lanes and ocean disposal sites contained in this subarea include all of the various ecosystems and habitats found in the mid-Atlantic region such as: shallow inner shelf, outer shelf, shelf break zone, canyon (Norfolk), continental slope, and continental rise. All of the typical mid-Atlantic faunal constituents would be found in this subarea. All of the threatened or endangered species occurring in the mid-Atlantic (peregrine falcon, Atlantic ridley turtle, loggerhead turtle, hawksbill turtle, leatherback turtle, green sea turtle, fin whale, sei whale, humpback whale, right whale, sperm whale, blue whale) could use parts of this subarea for feeding, migrating, or breeding/calving.

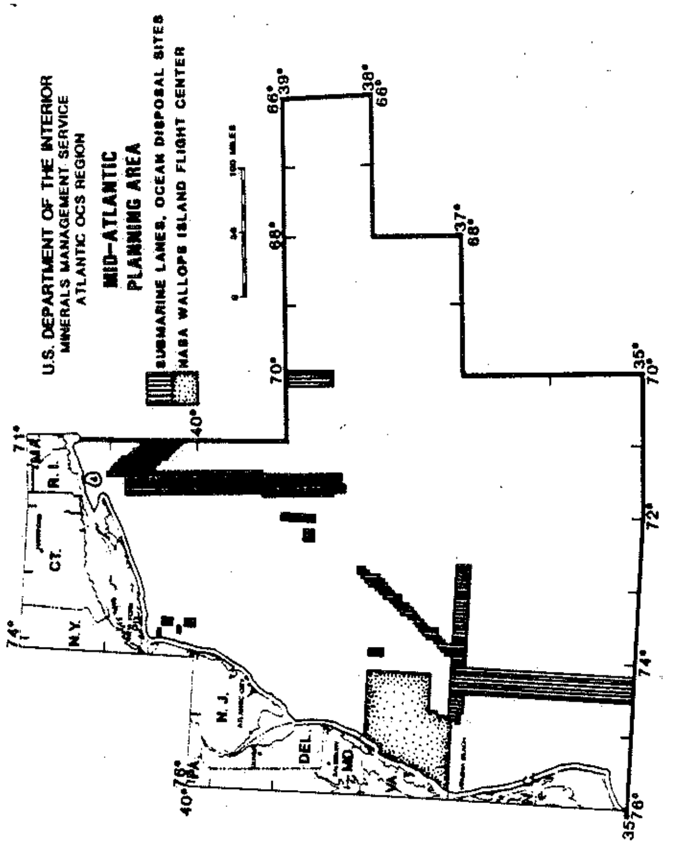
Submarine Lanes, Ocean Disposal Sites (Sale 111 FEIS) (Continued)

Potential Impacts Avoided by Deletion of this Subarea:

Adopting this deletion would preclude potential area use conflicts between OCS oil and gas activities and active ocean dumping. However, this does not seem to be a substantial impact reduction in that the mitigation of this use conflict can occur through planning and coordination. No significant change in water quality impact levels would occur.

Although this deletion candidate encompasses a sizable area (1,066 blocks) the amount of each specific habitat that may be affected is relatively low in comparison to the remaining planning area. In addition, the probability that a major oil spill would occur or move into the subarea would change very little, thereby dictating only a small decrease in impact level.





Planning Area: Mid-Atlantic Planning Area

Subarea Name: U.S.S. *Monitor* National Marine Sanctuary and Its Buffer Zone

Deferral Recommended by: Environmental Protection Agency, State of North Carolina, Natural Resources Defense Council

Geographic Description:

This candidate encompasses 6 blocks and covers an area of 13,824 hectares (34,158 acres). The buffer zone around the U.S.S. *Monitor* Marine Sanctuary consists of a vertical water column 1.8 km (1.1 mi) in diameter, extending from the surface to the seabed, the center of which is at 35° 00' 23" N latitude and 75° 24' 32" W longitude.

Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

U.S.S. *Monitor* and Its Buffer zone:

- Studied as an alternative in Sale 78 EIS
- Never leased

Oil and Gas Resource Potential:

Data coverage is limited within this subarea; however, its proximity to the potential exploration trend associated with the paleo-shelf edge complex off Cape Hatteras allows moderate potential for oil and gas occurrence.

No exploration wells are associated with the subarea and the most recent industry geophysical exploration activity in the area was in 1982.

Description of the Environment:

This subarea is in a well-sorted sand environment of approximately 60 m (197 ft) water depth. This subarea deferral candidate shares the same faunal consistuents as the Nearshore Block deferral candidate, which are dominated by mollusks, annelids, and primarily migratory fish. In addition, although the area is in a fairly high energy regime, some attached epifaunal and epifloral species are located at the U.S.S. *Monitor* site. Also, a single colony of the Seleractinean coral, *Oculina arbuscula*, are found on the wreck. This is apparently its northern limit.



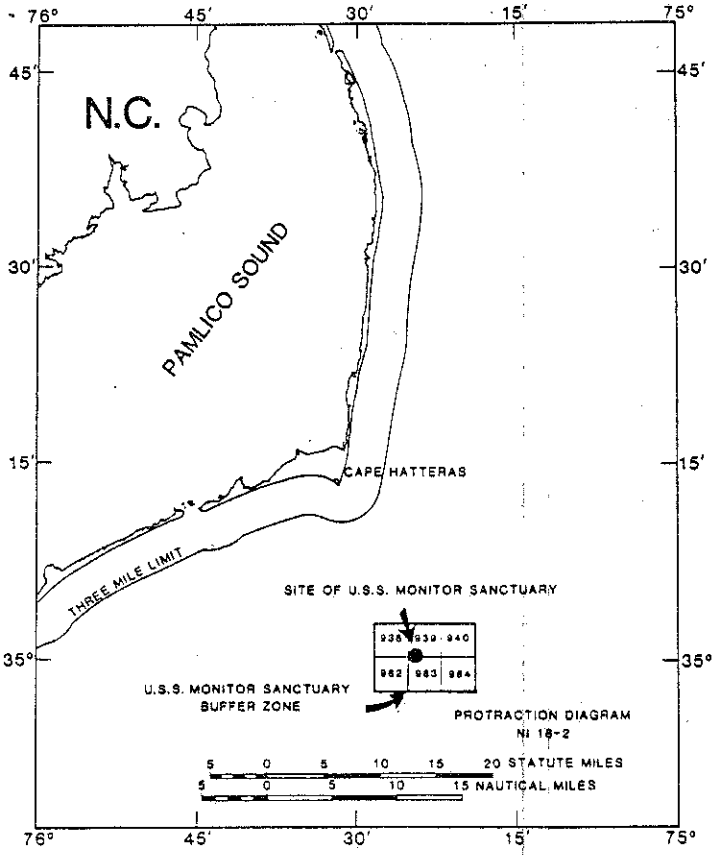
U.S.S. *Monitor* Marine Sanctuary and Its Buffer Zone (Continued)

Potential Impacts Avoided by Deferral of this Subarea:

OCS exploration activities which might raise concern about the stability and security of the U.S.S. *Monitor* wreck include high resolution profiling, disposal of drilling muds and cuttings, structural placements on the ocean floor, and oil spills. None of these activities, however, pose any substantial threat to the U.S.S. *Monitor*.

High resolution profiling in the area of the U.S.S. *Monitor* site has not been shown to accelerate deterioration of the wreck. Disposal of muds and cuttings from drilling platforms, if located in proximity to the U.S.S. *Monitor* wreck could increase the sediment load to the site. Chances are very remote that a surface oil spill could be entrained in the water column deeply enough to affect the U.S.S. *Monitor* site, however a subsurface blowout could pose a substantial risk to the marine sanctuary.

Deferral of this subarea would have a negligible effect on the potential impacts to biological resources of the planning area. However, local impacts would be mitigated.






Planning Area: Mid-Atlantic Planning Area

Subarea Name: Canyon head areas (Area ID Canyon Blocks Deleted Plus Sale 111 FEIS, Alternative 5 Plus Sale 111 SID)

Deferral Recommended by: State of Virginia, State of New York, State of North Carolina, Virginia Council on the Environment

Geographic Description:

This candidate encompasses 164 blocks and covers an area of 377,856 hectares (933,682 acres). This area includes whole or partial blocks located within or around the canyon areas, flanks, and axes of Block, Hudson, Toms, Carteret, Lindenkohl, Spencer, Wilmington, Baltimore, Accomac, Washington, and Norfolk Canyons. These blocks lie from approximately 104 to 241 km (65 to 150 mi) offshore in water depths ranging from approximately 100 to 900 m (328 to 2,952 ft).

Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

Canyon head areas:

°Studied in the following EIS's: Sales 49, 59, 76, 111
°Offered in the following Sales: 49, 59, RS-2
°14 leases as a result of Sale 49; no leases from 59 or RS-2
°Deferred from the following Sales: 76 and 111

Oil and Gas Resource Potential:

Acreages within this subarea are underlain by parts of the Jurassic/Cretaceous paleo-shelf-edge carbonate-buildup trend and contiguous zones of structural and stratigraphic traps. The deep water parts of some canyon head areas are located at or near the regionally defined stratigraphic trap zone associated with sediment onlap against the paleo-slope surface.

Data coverage is good and is sufficient to define specific prospects and stratigraphic traps as well as structural and stratigraphic trends.

Association with the paleo-shelf-edge carbonate-buildup makes the deep water parts of the subarea highly prospective with regard to oil and gas. In contrast, the shallower water parts being more remote from this buried shelf-edge complex are considered less prospective, although a few structures do occur. Overall, petroleum potential of this subarea is deemed high.

Canyon head areas (Area ID Canyon Blocks Deleted Plus Sale 111 FEIS, Alternative 5 Plus Sale 111 SID) (Continued)

This subarea includes one industry well (EXXON 816-1, Toms Canyon deletion) that was drilled to a total depth of 5,413 m (17,756 ft). Rocks of mainly Cretaceous and Jurassic age were encountered, some of which could provide good reservoirs. Several gas shows were reported below 3,963 m (13,000 ft) and post-drilling geochemical analysis suggests that source rocks, although organically lean, are mature enough to generate hydrocarbons.

The most recent industry geophysical exploration activity in the subarea occurred in 1983.

Description of the Environment:

The physiography of the middle Atlantic continental slope is dominated by numerous submarine canyons which cut into the slope in varying degrees. The major canyons along the Middle Atlantic Bight incise deeply (up to 150 km or 93 mi) into the shelf while the minor canyons are located on the upper and middle slope, or barely reach the shelf edge.

Because of the past or present erosional nature of the canyon head areas, the topography tends to be rugged and highly diverse. The outcroppings formed by the more consolidated sediments provide a greater amount of attachment substrate than is typically found along the rest of the continental margin. Although, in general, the biomass and numbers of organisms decrease in a seaward direction from the outer shelf to the slope and beyond, submarine canyons have been shown to have increased biomass and numbers of organisms. The primary reason for increased density is the complex topography located at the canyon heads and along the shear walls. In conjunction with increased niche space because of topographic complexity, increased attachment substrate--in the form of consolidated sediment or rock scarps--allows sessile invertebrates to colonize these areas, thereby increasing the number of available niches for other fauna which may associate with these colonies.

Recent research has indicated that canyons, in general, with their increased exposure of outcrops have large populations of attached filter-feeding species, while the comparable slope areas are dominated by mobile scavengers. The increased density of filter feeders in canyons also supports the hypothesis that the canyons are conduits for particulates (including particulate organics) from the continental slope to the abyss.

Coral populations tend to be more diverse in middle Atlantic canyon habitats than in the adjacent slope areas. The primary reason for increased diversity in the canyons is that those species restricted to hard substrates are found only in canyons, but soft-substrate types are found both in the canyons and on the slope.



Canyon Head Areas (Area ID Canyon Blocks Deleted Plus Sale 111 FEIS, Alternative 5 Plus Sale 111 SID) (Continued)

Potential Impacts Avoided by Deletion of this Subarea:

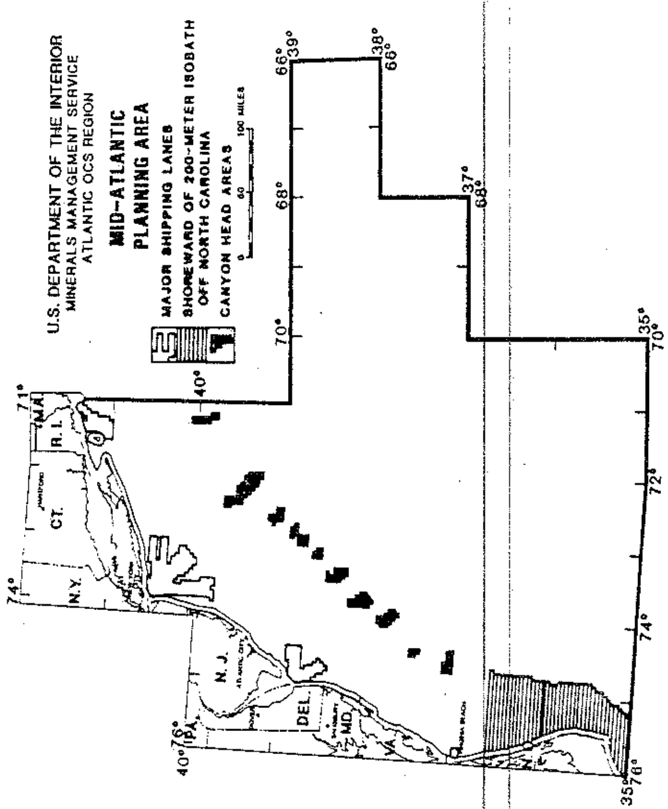
No change in overall water quality impact levels would occur.

The mechanical damage that results from the placement of structures such as pipelines, well complexes, platforms, and wellheads is highly localized and would be avoided in the major canyon areas under this subarea deletion.

The greatest impact avoided results from mechanical damage which could occur in the "pueblo village" areas of canyon heads. These areas are extensive burrow systems that support a number of species such as tilefish, lobster, red crab, and cancer crabs. They would be highly susceptible to mechanical damage resulting from structure placement.

Chronic discharges of mud and cuttings pose little threat to canyon systems. Acute discharges which would be expected to cause the greatest impact would be avoided. Spudding of the well and detachment of the riser could release drilling muds and cuttings directly at the sea floor. It is estimated that depending upon the oceanographic current regime, about 744 $m^2$ (18,000 $ft^2$) of sediment surface could be covered by up to 1 m (3.3 ft) of drill muds and cuttings during the initial spudding-in process. However, no estimate of areal coverage is available for riser detachment.

Surface oil spills should have no major impact on canyon areas because of the water depths of the areas. Petroleum hydrocarbons can reach the canyon areas by adsorption onto particulates that may settle out of the water column to the canyons, or by incorporation into zooplankton fecal pellets which then sink to the bottom. In both these cases, the impact on the canyon areas is expected to be negligible because of the dispersed nature of the particles. A subsurface oil spill within a canyon, however, could pose an appreciable threat to the biota in its vicinity. This potential impact would be avoided in canyon systems deleted under this option.






Planning Area: Mid-Atlantic Planning Area

Subarea Name: NASA Wallops Island Flight Center at Wallops Island, Virginia

Deferral Recommended by: State of North Carolina, National Aeronautics and Space Administration

Geographic Description:

This candidate encompasses 385 blocks and covers an area of 866,278 hectares (2,140,621 acres). This area is a large zone situated east of Accomack, Virginia. It extends from the State territorial water boundary out to an approximate water depth of 1,200 m (3,936 ft); about 128 km (80 mi) from shore.

Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

NASA Wallops Island Flight Center at Wallops Island, Virginia:

- Studied in Sale 111 EIS
- Deferred from Sale 76
- Deferral alternative in Sale 111

Oil and Gas Resource Potential:

The eastern part of this subarea encompasses the western half of the Baltimore Canyon Trough sedimentary basin where total sediment thickness, locally, may exceed 15,243 m (50,000 ft). Triassic rift-basins containing stratigraphic traps appear to be present within the subarea, although no structural traps have been mapped. An early Jurassic shelf-edge stratigraphic trend lies subparallel to and within the easternmost part of the subarea.

A possible exploration trend consisting of both structural and stratigraphic traps associated with the Jurassic/Cretaceous shelf-edge complex is located along the eastern edge of the subarea.

Except for a small area off Virginia, data coverage within the subarea is limited. Locally, some nearshore areas have no data coverage at all.

Some parts of the subarea appear to be not as prospective as others within the planning area. Elsewhere, prospectiveness cannot be determined because of lack of data. Hydrocarbon potential is considered highest along the seawardmost parts of the subarea.

No industry wells have been drilled in the subarea, and the latest geophysical exploration activity by industry occurred in 1982.

NASA Wallops Island Flight Center at Wallops Island, Virginia (Continued)

Description of the Environment:

This subarea predominantly consists of continental shelf habitat and some slope habitat. The shelf waters are relatively low in salinity and are subject to strong seasonal cooling or warming, and tidal effects. This subarea is important as part of the habitat for development of fish eggs and larvae, but no distinct spawning areas are evident. The benthic habitat is characterized by medium-grained sand inshore, grading to finer sediments offshore. A ridge-and-swale mesoscale topography is apparent on the inner and outer portions of the shelf. Polychaetes and mollusks dominate on the shelf, but decrease in importance seaward as the numerical dominance of crustaceans increases.

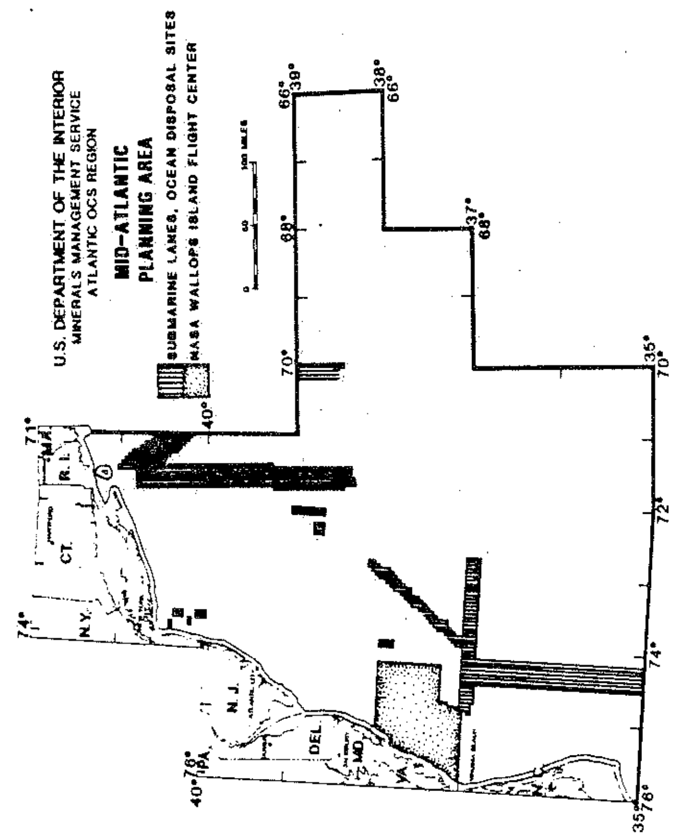
Potential Impacts Avoided by Deletion of this Subarea:

This subarea deletion would eliminate all potential for onshore visual impacts to the Delmarva portion of the Virginia coast resulting from offshore drilling facilities. The risk of impacts to coastal recreation areas from platform spills would also be slightly reduced.

No significant change in water quality impact levels would occur.

No significant potential impacts would be expected on this area's biological functions. Therefore, deletion of this area would maintain the already negligible impacts expected.





Planning Area: Mid-Atlantic Planning Area

Subarea Name: All Blocks in Water Depths greater than 3,000 meters (Mid-Atlantic)

Deferral Recommended by: Chevron

Geographic Description:

This candidate encompasses 7,119 blocks and covers an area of 16,402,176 hectares (40,529,776 acres). These blocks lie in the far eastern and southeastern portion of the planning area in water depths as great as 5,000 m (16,400 ft). They lie as close as 96 km (60 mi) from Cape Hatteras and as far as 724 km (450 mi) from Atlantic City, New Jersey.

Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

Blocks in water depth greater than 3,000 meters, Mid-Atlantic:

- Not studied as an alternative at the EIS stage
- Previously offered in Sales 59 and 76 with no leases issued

Oil and Gas Resource Potential:

Except for widely-spaced regional lines, data coverage is sparse. Therefore, oil and gas potential is unknown.

No industry wells have been drilled in this subarea and the most recent industry geophysical survey was conducted in 1980.

Description of the Environment:

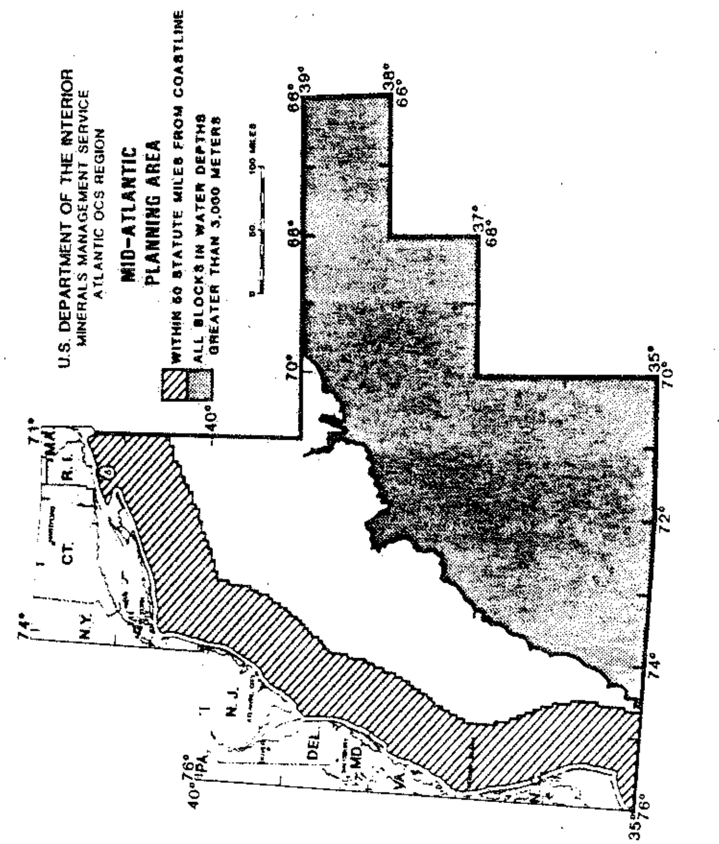
Benthic and epibenthic species are found at these great depths, however, densities decrease dramatically from the slope down. Small annelids and crustaceans comprise the majority of the animals found.

Potential Impacts Avoided by Deletion of this Subarea:

Due to the great water depth and distance from land, potential impacts due to OCS activities are negligible. Deletion of this subarea would avoid these negligible impacts.

Water quality impact levels would remain unchanged.





Planning Area: Mid-Atlantic Planning Area

Subarea Name: Within 50 Statute Miles from Coastline (Rhode Island to North Carolina)

Deferral Recommended by: State of Connecticut, State of New Jersey, State of New York, State of Virginia, Virginia Council on the Environment, Natural Resources Defense Council, Greenpeace

Geographic Description:

This candidate encompasses 2,961 blocks and covers an area of 6,658,363 hectares (16,453,175 acres). This area would include all the blocks on the continental shelf that lie within 80 km (50 mi) of the coastline between Rhode Island and North Carolina.

Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

Within 50 statue miles from coastline in Mid-Atlantic:

- o Not studied as an alternative at the EIS stage
- o Deferred at Area Identification stage-Sale 111

Oil and Gas Resource Potential:

This subarea mostly covers the continental shelf (less than 100 m (328 ft) water depth) except off Cape Hatteras where it includes the continental slope and rise to 2,800 m (9,184 ft) water depth.

In the northern part of the Planning Area, this subarea encompasses the western flank of the Baltimore Canyon Trough sedimentary basin where total sediment thicknesses may approach 15,243 m (50,000 ft). Off Cape Hatteras, the northern extension of the Carolina Trough, another area of thick sediment accumulation is included in the deletion option.

North of Cape Hatteras existing data coverage is sparse nearshore and fair to good further offshore. Data coverage is generally adequate to define regional structural and stratigraphic trends and, is occasionally sufficient to delineate specific prospects and plays. Data coverage offshore Cape Hatteras is fair to good and is sufficient to determine specific prospects and plays as well as stratigraphic and structural trends.

The seaward part of the subarea off Hatteras includes an area associated with the Jurassic/Cretaceous paleo-shelf edge carbonate trend and contiguous zones of structural and stratigraphic trapping. A middle Jurassic shelf-edge stratigraphic trend lies subparallel to and within the easternmost part of the subarea off Virginia and Maryland. The landward parts of this deferral overlie Triassic age rift-basins that may contain structural and stratigraphic traps. Deposits within these rift basins have recently been of interest for oil and gas exploration elsewhere along the Atlantic margin of the eastern United States, as well as within similar basins that lie buried beneath the adjacent onshore coastal plain deposits.



Within 50 Statute Miles from Coastline (Rhode Island to North Carolina) (Continued)

In terms of prospectiveness, the southernmost part of the deletion option (off Cape Hatteras) is considered more prospective than elsewhere within the option area because of the inclusion of the potential exploration trend associated with the paleo-shelf edge complex. Most of the subarea occurs in areas of low to moderate potential for oil and gas occurrence; however, off Hatteras, it includes areas of high potential. A few nearshore areas contain no data coverage, thus prospective areas cannot be deduced.

At present, no industry wells have been drilled within the subarea and the latest industry geophysical activity occurred in 1983.

Description of the Environment:

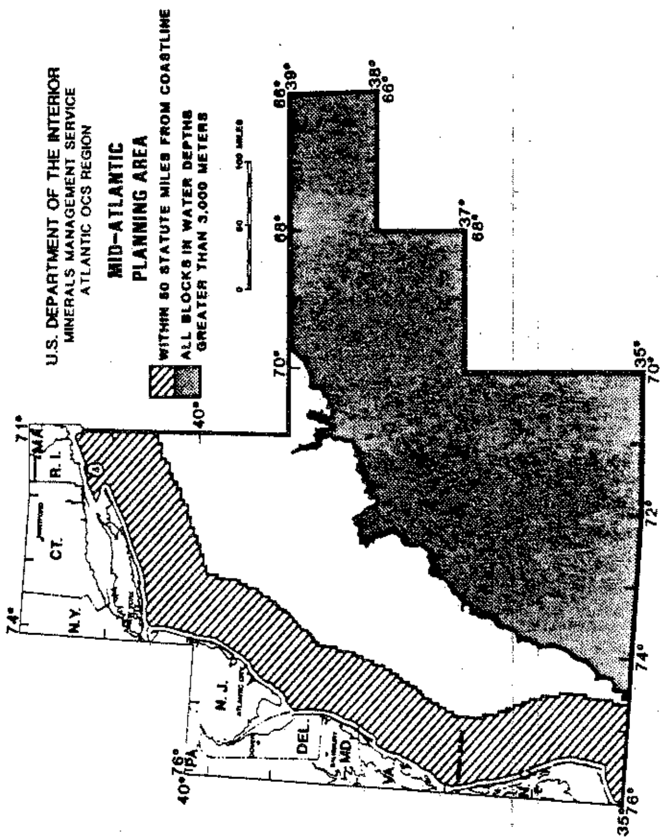
This deferral alternative would include the major portion of the continental shelf in the Mid-Atlantic Planning Area. The benthic environment consists of medium-grained sand nearshore, grading to finer sands offshore. The number of organisms/$m^2$ tends to increase in the seaward direction, primarily as a result of small polychaetes associated with the finer sediment. Other invertebrate species found in the area would include the commercially important sea scallop, ocean quahog, and surf clam as well as sand dollars, starfish, and Cancer crabs. The majority of the commercial fishery landings in the mid-Atlantic region--taken outside of State waters -- are in this subarea deferral candidate.

The endangered right whale is reported to use this area as a migration route during the fall, and other species of marine mammals (primarily delphinids) are common in the area. Two species of endangered sea turtles, the leatherback and Atlantic ridley turtles, and one threatened species, the loggerhead turtle, are likely to be found in the area between spring and fall. Two other species, the endangered hawksbill turtle and threatened green sea turtle are rare transients.

Potential Impacts Avoided by Deferral of this Subarea:

Deferral of this subarea would appreciably reduce the potential for conflicts with the commercial fishing activity resulting from spatial exclusion. However, the estimated impact on fisheries resources would not be reduced. Potential impacts on onshore visual aesthetics resulting from drilling structure placement would be eliminated. Impacts on archaeological resources would be reduced to negligible. The potential direct local impacts on endangered or threatened species would be significantly reduced in the deferral area, but the overall impact estimated for the mid-Atlantic area would be unchanged.

Selection of this deferral option is not expected to show any significant reduction in regional water quality impacts. Locally, however, there may be a reduction in water quality impacts.






Planning Area: Mid-Atlantic Planning Area

Subarea Name: Nearshore/Low Potential Block Deferral

Deferral Recommended by: Environmental Protection Agency, Murphy Oil USA, Natural Resources Defense Council

Geographic Description:

This candidate encompasses 1,748 blocks and covers an area of 3,662,208 hectares (9,049,316 acres). It consists of the area on the continental shelf shoreward of a line that runs northeast-southwest from the planning area's northern boundary located 140 km (87 mi) south of Newport, Rhode Island, to the southern boundary which is 30 km (18 mi) south of Cape Hatteras, North Carolina.

Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

Nearshore Block Deferral:

- Not studied as an alternative at the EIS stage
- Deferred at Area Identification stage--Sale 111

Oil and Gas Resource Potential:

This subarea is restricted to nearshore continental shelf areas in water depths of 40 m (131 ft) or less, except in the northern part off southern New England, where it extends locally out to 80 to 100 m (260 to 328 ft).

Existing data coverage over most of the subarea is very sparse to nonexistent. However, off Cape Hatteras, data coverage is fair to good, sufficient to identify major structural trends and, in places, define specific prospects.

The subarea occurs atop the shallow basement platforms of the inner margin (i.e., adjacent to and shoreward of the deep offshore sedimentary basins) where total sediment thicknesses are markedly reduced, generally less than 3,049 m (10,000 ft). Triassic rift-basin (graben) deposits are known to occur locally within this subarea, notably in the central and northernmost parts. However, structural and stratigraphic traps have yet to be identified owing to the paucity of data over most of the subarea.

The southernmost part of the subarea (off Cape Hatteras) lies just landward of the Jurassic-Cretaceous paleo-shelf edge exploration trend.

Nearshore/Low Potential Block Deferral (Continued)

This subarea largely includes areas of low industry interest (based on Sale 111 Area Identification) and present oil and gas potential is considered low to moderate and, in places, cannot be determined due to lack of data.

To date, no industry wells have been drilled within the subarea and the most recent industry geophysical activity in the subarea occurred in 1982.

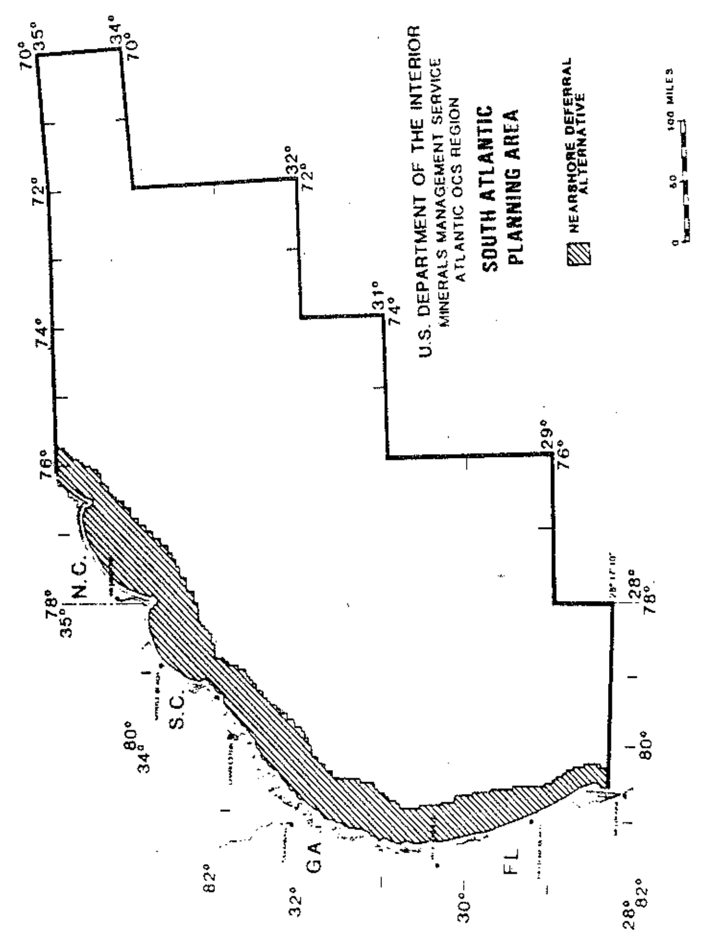
Description of the Environment:

This subarea alternative consists of a shallow water area which generally has a poorly sorted, medium grain size sand bottom. The primary infaunal and epifaunal species are polychaetes, mollusks (surf clam, ocean quahog), echinoderms (sand dollars, starfish), and crustaceans (lobsters, crabs). Some valuable commercial fisheries (menhaden, sea scallop, surf clams) harvest part of their landings in the area, but no specific highly-productive biological areas are present. Several species of marine and shore birds are commonly found in the subarea and many additional species -- including the threatened arctic peregrine falcon -- migrate seasonally through the area. Sea turtles are seasonally present in this subarea, and two endangered species (leatherback and Atlantic ridley) and one threatened species (loggerhead) are likely to be in the subarea from late spring to late fall. The endangered hawksbill turtle and the threatened green sea turtle may be rarely present. A number of marine mammals are seasonally present in the subarea and, of the endangered cetaceans, the right whale is the most likely to be evident.

Potential Impacts Avoided by Deferral of this Subarea:

Deferral of this subarea would eliminate all potential for onshore visuals impacts on the coasts of the mid-Atlantic states which may result from the placement of drilling structures. The potential impacts to the coastal recreation areas could be reduced from the proposed action. Impacts on archaeological resources would be reduced, but would still remain at the very low level. Selecting this deferral alternative would reduce conflicts with the fisheries industry resulting from competitive exclusion for space. However, no change in overall impact level is anticipated. Deferring this subarea would reduce the potential impacts to endangered and threatened species, but the estimated regional impact level would be unchanged. No change in impact level for air or water quality is expected under this alternative.





Planning Area: South Atlantic Planning Area

Subarea Name: National Marine Sanctuary (Gray's Reef)

Deferral Recommended by: Environmental Protection Agency, State of North Carolina , Natural Resources Defense Council, Chevron, Murphy Oil USA

Geographic Description:

This candidate encompasses 6 blocks and covers an area of 13,824 hectares (34,159 acres). This area includes blocks containing Gray's Reef National Marine Sanctuary which lies 32 km (20 mi) east of Sapelo Island, Georgia. The sanctuary occupies an area of 57 $km^2$ (22 $mi^2$).

Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

National Marine Sanctuaries (Gray's Reef):

° Not studied as an alternative at the EIS stage
° Never leased

Oil and Gas Resource Potential:

This subarea is located on the inner continental shelf off Georgia in less than 40 m (131 ft) of water.

Very little data coverage exists over this area.

A trend of structural traps which extends northeastward from the Southeast Georgia Embayment lies seaward of this subarea.

Industry interest in this subarea (based on Sale 90 Area Identification) is low and the resource potential is largely unknown because of a lack of data.

No wells have been drilled within the area of this deferral alternative, and the most recent geophysical exploration activity occurred in 1975.

Description of the Environment:

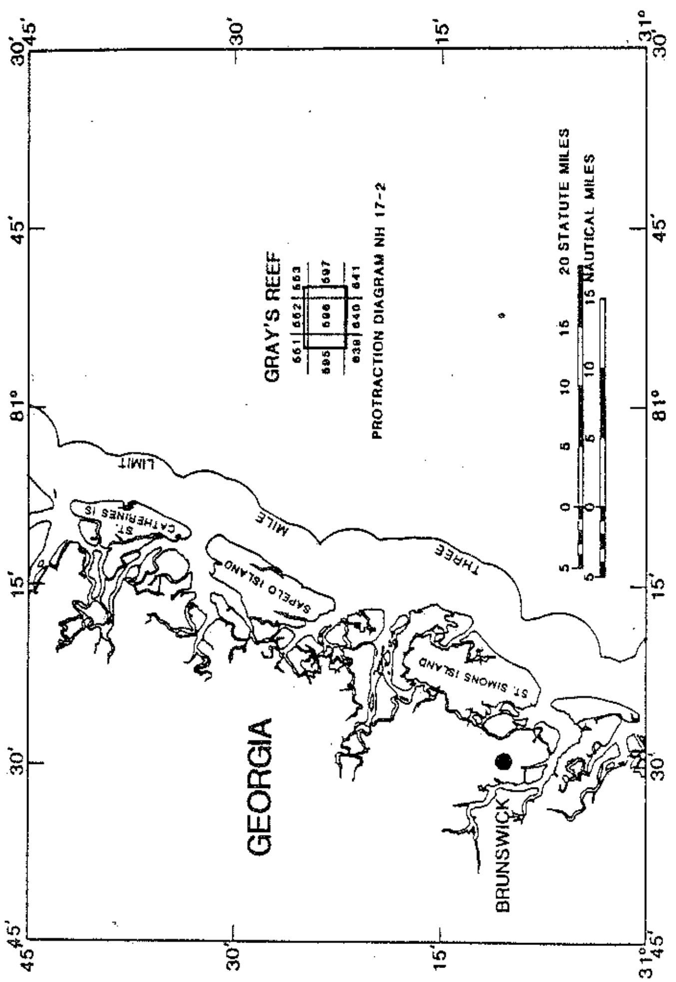
The sanctuary is a biologically productive, moderate-to-high relief, live-bottom reef. The reef supports a variety of biota including an array of seaweeds, invertebrates, fish, and turtles. The sanctuary demonstrates the subtropical community profile which is common to all live-bottom areas in the South Atlantic, and is a valuable research area for the study of reef environments.

Potential Impacts Avoided by Deletion of this Subarea:

Impacts to regional water quality would remain unchanged.

Deletion of this area would avoid any possible impacts from standard OCS oil and gas operations to Gray's Reef.





Planning Area: South Atlantic Planning Area

Subarea Name: Inner Shelf (Ten Fathom Ledge)

Deferral Recommended by: State of North Carolina

Geographic Description:

This candidate encompasses 18 blocks and covers an area of 41,472 hectares (102,477 acres). This area lies 27 km (17 mi) due south of Cape Lookout, North Carolina, and occupies an area of approximately 350 $km^2$ (135 $mi^2$). It lies at an approximate water depth of 25 m (82 ft) and is bounded by the following coordinates - 34° 26'N, 76° 37'W; 34° 34'N, 76° 37'W; 34° 20'N, 76° 29'W; 34° 13'N, 76° 29'W.

Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

The Inner Shelf--27 km (17 mi) south of Cape Lookout (Ten Fathom Ledge):

- Not studied as an alternative at the EIS stage
- Never leased

Oil and Gas Resource Potential:

This subarea is located on the inner portion of the outer continental shelf off North Carolina in less than 40 m (131 ft) of water.

Data coverage over most of this area is sparse.

This deferral alternative subarea lies on the landward edge of a trend of structural traps.

Industry interest in this subarea (based on Sale 90 Area Identification) is low, and the resource potential is unknown because of a lack of data.

No wells have been drilled within the area of this deferral alternative, and the most recent geophysical exploration activity occurred in 1980.

Description of the Environment:

The inner portion of the outer continental shelf off North Carolina is primarily soft bottom and low-relief hard bottom. Low-relief hard bottoms can support live bottom assemblages with sparse to moderate occurrence of sessile epibenthos. An abundance of attached macroalgae exist in the area. The area is part of a larger one which runs as a band along the south Atlantic coastline. This band basically defines the in-shore fisheries for red drum, weakfish, striped bass, bluefish and kingfish. The major human use of the Ten Fathom Ledge/Big Rock complex is recreational, including SCUBA diving and recreational fishing.



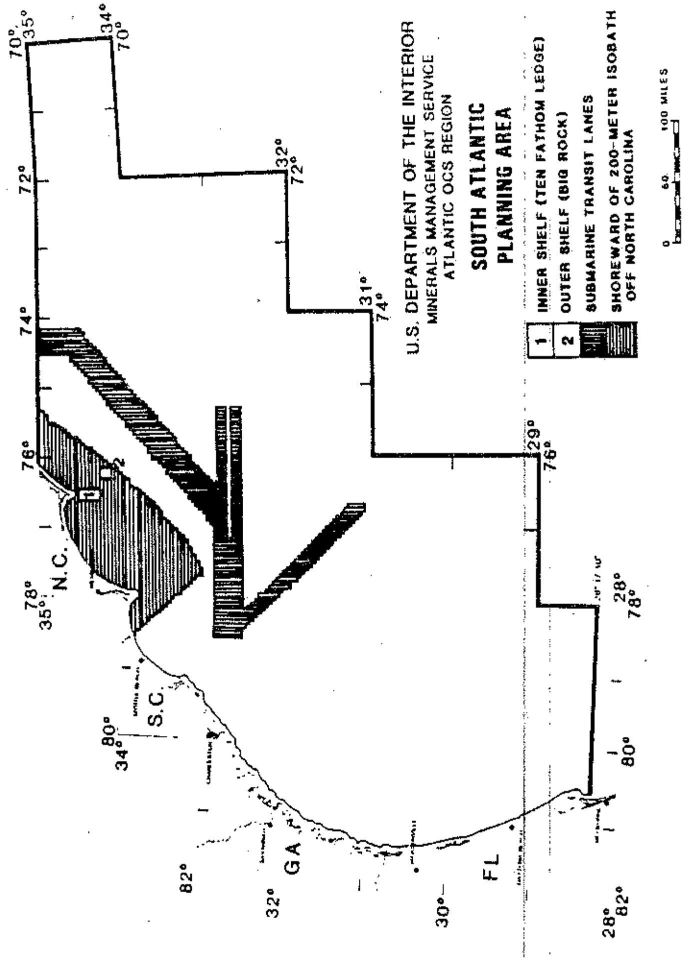
Inner Shelf (Ten Fathom Ledge) (Continued)

Potential Impacts Avoided by Deletion of this Subarea:

This subarea deletion would eliminate some of the potential for onshore visual impacts to the Cape Lookout area of North Carolina resulting from offshore drilling facilities. Potential conflicts between oil and gas exploratory activity and recreational use of the area would be avoided by this deletion.

Impacts to regional water quality would remain unchanged.

Deletion of this area would avoid local impacts on the low-relief hard bottom areas and the present fisheries, but would not affect regional impact levels.






Planning Area: South Atlantic Planning Area

Subarea Name: The Outer Shelf (Big Rock)

Deferral Recommended by: State of North Carolina

Geographic Description:

This candidate encompasses 9 blocks and covers an area of 20,736 hectares (51,238 acres). This area lies 58 km (36 mi) south of Cape Lookout and occupies an approximate area of 10 $km^2$ (4 $mi^2$). It lies in an approximate water depth of 40 to 50 m (131 to 164 ft) and is bounded by the following coordinates 34° 12'N, 76° 15'W; 34° 7'N, 76° 15'W; 34° 12'N, 76° 10'W; 34° 7'N, 76° 10'W.

Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

The Outer Shelf-58 km (36 mi) offshore (Big Rock):

- Not studied as an alternative at the EIS stage
- Never leased

Oil and Gas Resource Potential:

This subarea is located on the outer continental shelf in water depth of approximately 40 to 50 m (131 to 164 ft) of water. It is situated on the landward boundary of the Carolina Trough sedimentary basin where total sediment thickness may, in places, exceed 10,670 m (35,000 ft).

Data coverage over most of this area is sparse.

This deferral alternative subarea lies on the landward edge of a trend of structural traps.

Industry interest in this subarea (based on Sale 90 Area Identification) is low, and the resource potential is unknown because of a lack of data.

No wells have been drilled within the area of this deferral alternative and the most recent geophysical exploration activity occurred in 1980.

Description of the Environment:

Big Rock is an area on the continental shelf break which has several fish populations of commercial importance. This subarea deletion candidate combined with the Ten Fathom Ledge subarea deletion candidate, is on the Site Evaluation List for marine sanctuaries and has been nominated for Preliminary Consultation before being recommended for sanctuary status. This area, although deeper and less diverse than Ten Fathom Ledge, is an example of subtropical populations at their northern extreme.

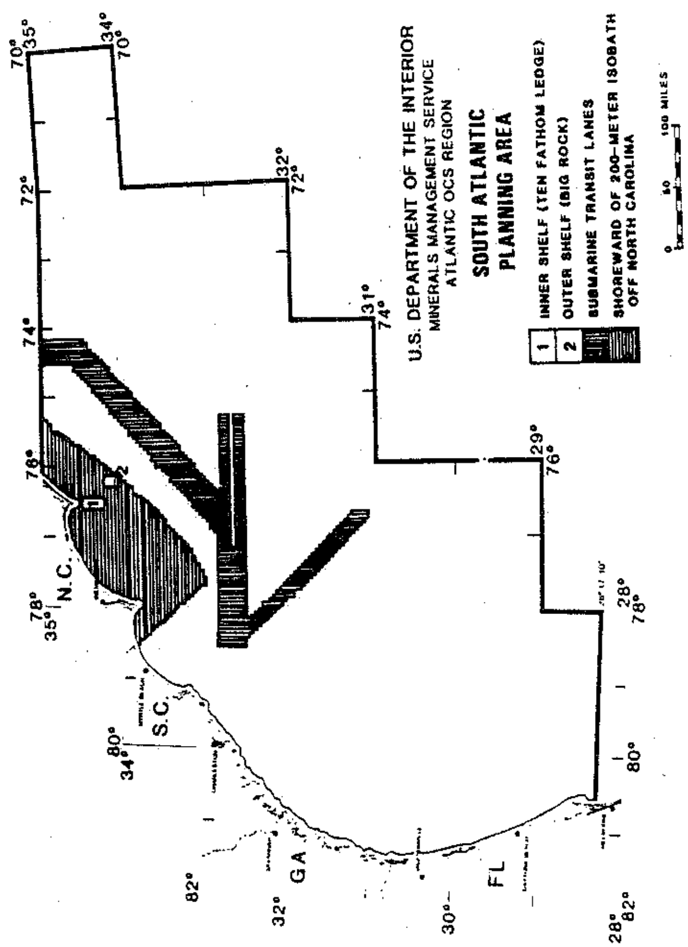
The Outer Shelf (Big Rock) (Continued)

Potential Impacts Avoided by Deletion of this Subarea:

Impacts to regional water quality would remain unchanged.

Deletion of this subarea would prevent the potential major impacts to these unique biological systems. However, no change in regional impact levels is anticipated.





Planning Area: South Atlantic Planning Area

Subarea Name: Flight Clearance Zone of the Kennedy Space Center

Deferral Recommended by:

Environmental Protection Agency; National Oceanic and Atmospheric Administration; State of Florida; State of North Carolina; Volusia County, Florida; Brevard County, Florida; National Aeronautics and Space Administration; Natural Resources Defense Council; Friends of Canaveral; Murphy Oil USA; Greenpeace; Senator Lawton Chiles; Sierra Club (Texas Chapters)

Geographic Description:

This candidate encompasses 3,424 blocks and covers an area of 7,690,525 hectares (19,003,701 acres). This area lies off the coasts of southern Georgia and northern Florida. It is predominantly located between 31° and 27° N latitude and extends from the immediate coastline eastward out into water depths as great as 2,000 m (6,560 ft) at approximately 77° W longitude.

Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

- Studied as an alternative in Sale 78 EIS
- Deferred in Sale 78
- Deferred in Sale 90 Area Identification

Oil and Gas Resource Potential:

This subarea includes a large part of the Blake Plateau Basin, an area of thick sediment accumulation that, locally, may exceed 10,670 m (35,000 ft).

Data coverage over most of the area is adequate to define specific prospects or trends; however, in some areas the coverage is sparse.

The subarea contains a number of broad, low relief anticlinal structures that are generally confined to the central and eastern parts of the subarea. Triassic basins occur along the nearshore portion of this subarea.

Industry interest in this subarea (based on Sale 90 Area Identification) is low except for a narrow strip of high interest in the nearshore portion of the area. The resource potential is considered low to moderate.

No wells have been drilled within this deferral alternative subarea and the most recent geophysical exploration activity occurred in 1983.



Flight Clearance Zone of the Kennedy Space Center (Continued)

Description of the Environment:

The area encompasses parts of the geological features known as the Florida-Hatteras Shelf and the Blake Plateau. These features are found in water depths of 400 m (1,312 ft) and 600 to 1,000 m (1,968 to 3,280 ft), respectively. The shelf surface is not flat but characterized by numerous sand ridges which trend at low angles to the coast. Other irregularities include scattered outcrops of live bottoms. The Blake Plateau is generally broad and flat and characterized by terrace like intervals found at 800, 900, 1,000, and 1,100 m water depth (2,624, 2,952, 3,280, and 3,608 ft). The western margin is characterized by the appearance of live, deep-water coral mounds. The Florida-Hatteras Shelf has been delineated into three subtidal sand-bottom assemblages; 0 to 20 m (0 to 66 ft) (turbulent zone), 40 to 120 m (131 to 394 ft) (outer continental shelf), and 160 to 205 m (525 to 672 ft) (upper continental shelf). The sand dollar Mellita quinquiesperforata and polychaetes dominate the turbulent zone. The outer and upper zones are dominated by species of polychaetes and amphipods. The continental slope area is considered to be depauperate in comparison to the shelf.

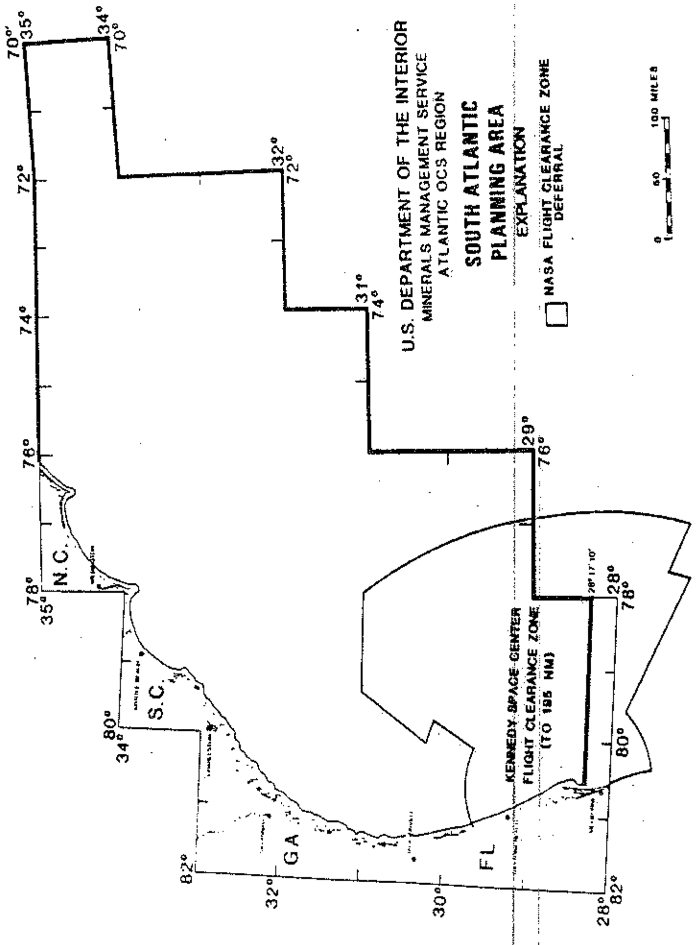
The deeper region between 400 to 1,000 m (1,312 to 3,280 ft) is an area known for sport fishing of "blue water" species. Other than some tuna that exhibit schooling behavior, many species occur either singly or in pairs. There also exists distinct deep-water fauna such as anglerfish, rattails, hakes, and deep-sea synaphobranchid eels. Generally, these species are distributed in discrete depth zones.

Potential Impacts Avoided by Deletion of this Subarea:

This subarea deletion would eliminate any potential for onshore visual impacts to the Florida coast between Cape Kennedy and Daytona Beach resulting from offshore drilling facilities. The risk of impacts to coastal recreation areas from platform spills would also be slightly reduced.

This deletion would not likely change the overall regional impacts to water quality within the planning area. Risks of contamination resulting from oil and gas related activities may, however, be reduced locally.

Deletion of this area would avoid possible local impacts to nearshore shallow water communities and eliminate the low potential impacts to local deep-water areas. No change in regional impact levels is expected.






Planning Area: South Atlantic Planning Area

Subarea Name: Submarine Transit Lanes

Deferral recommended by: State of North Carolina

Geographic Description:

This candidate encompasses 1,138 blocks and covers an area of 2,621,952 hectares (6,478,843 acres). The submarine transit lanes within the South Atlantic Planning Area lie within deep waters southeast of North Carolina and South Carolina.

Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

Submarine transit lanes off the coasts of North Carolina, South Carolina, and Florida:

° Not studied as an alternative at the EIS stage.
° Offered in Sales 43 (0 leases), 56 (10 leases), RS-2 (4 leases), and 78 (0 leases).

Oil and Gas Resource Potential:

This subarea is located off North Carolina, South Carolina, and Georgia in water depths ranging from 100 to 3,500 m (328 to 11,480 ft).

Data coverage over most of the subarea is fair to good and sufficient to define specific prospects.

The central parts of the subarea contain the Jurassic/Cretaceous carbonate paleo-shelf edge trend and associated structural and stratigraphic traps.

Industry interest in the central parts of the subarea (based on Sale 90 Area Identification) ranges from moderate to high. The resource potential of this area is considered moderate to high.

No wells have been drilled within the area of this deferral alternative. The most recent geophysical exploration activity occurred in 1984.

Submarine Transit Lanes (Continued)

Description of the Environment:

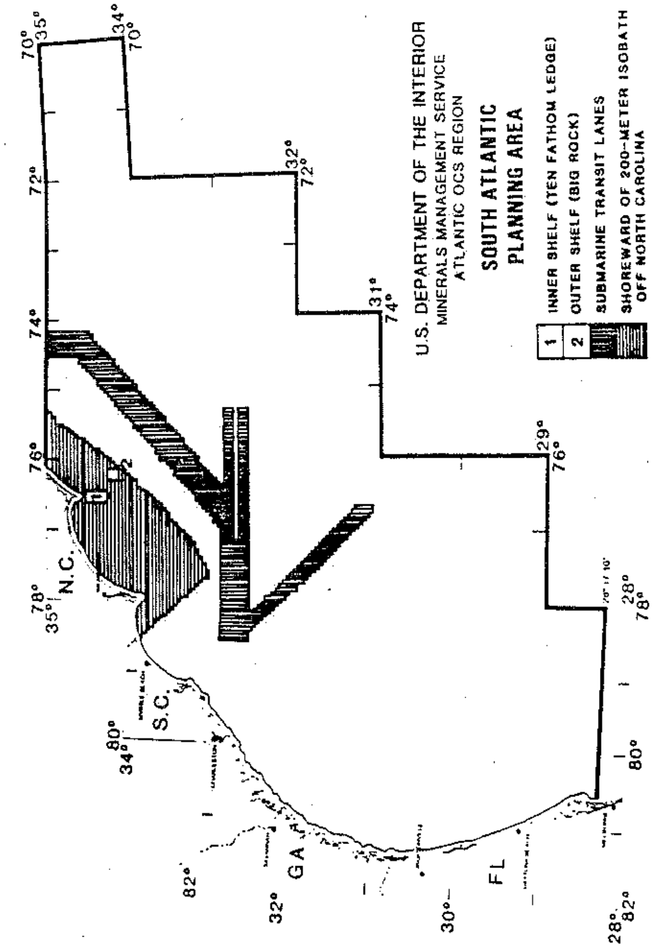
The transit lanes are primarily in deep water areas where the predominant communities consist of annelid species. Individual density within the area is highest on the upper slope at about the 600 m (1,968 ft) isobath. Density is lower at the 1,500 m (4,920 ft) isobath and then increases again at 2,000 m (6,560 ft). Density then decreases sharply at the 3,000 and 3,500 m (9,840 and 11,480 ft) isobaths. The most landward section contains 100 m (328 ft) depths where high-relief live bottoms may be located, and which can support an abundance of encrusting corals, sponges, and associated live assemblages. The deeper live bottom areas on the shelf break have a lower incidence of large sponges and octocorals.

Potential Impacts Avoided by Deletion of this Subarea:

Impacts to regional water quality will not be significantly reduced.

Because of the water depth, sparsity of live bottoms, and shifting abundances of fish, the potential for impacts in this area is low. Deletion of this area would reduce the low local impacts expected in the area.





Planning Area: South Atlantic Planning Area

Subarea Name: All blocks lying in water deeper than 3,000 meters (South Atlantic)

Deferral Recommended by: Chevron

Geographic Description:

This candidate encompasses 6,290 blocks and covers an area of 14,492,160 hectares (35,810,127 acres). These blocks lie in the far eastern portion of the planning area where water depths may be greater than 5,000 m (16,400 ft). They lie as close to shore as 241 km (150 mi) east of Cape Lookout and as far as 708 km (440 mi) east of Charleston, South Carolina.

Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

Blocks in water depths greater than 3,000 meters, south Atlantic:

° Not studied as an alternative at the EIS stage
° Not offered

Oil and Gas Resource Potential:

Data coverage over the subarea is generally sparse to nonexistent except along the landward boundary of the area north of 32° 30' N latitude, where coverage is fair and sufficient to define specific prospects.

Structural and stratigraphic traps associated with salt diapirs, and the Jurassic/Cretaceous paleo-shelf-edge trend occur within the subarea above 32° 30' N latitude.

Industry interest in this subarea (based on Sale 90 Area Identification) ranges from low to moderate. The resource potential is largely unknown because of a lack of data. However, in the area north of 32° 30' N latitude where data coverage is sufficient, the resource potential is considered high.

No wells have been drilled within the area of this deferral alternative, and the most recent geophysical exploration activity occurred in 1982.



All blocks lying in water deeper than 3,000 meters (South Atlantic) (Continued)

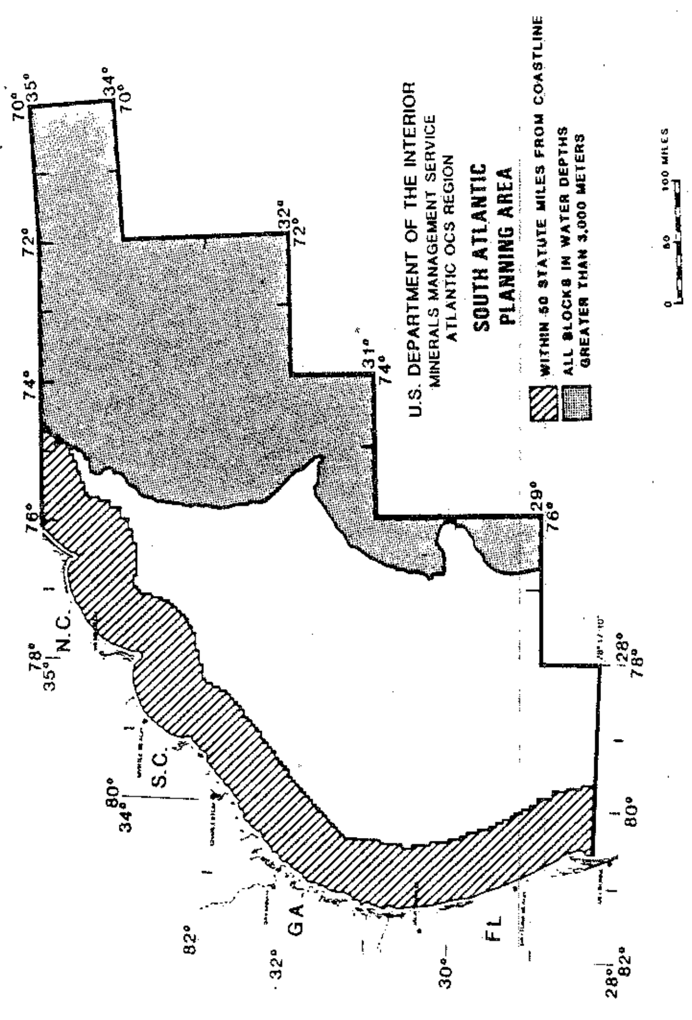
Description of the Environment:

The area is deep water and the water temperatures are cold (less than 3.5° C). The benthic faunal communities which have been sampled have demonstrated low total diversity and density. The primary faunal constituents are polychaetes, echinoderms, brotulid fish, and the macrourid fish Coryphaenoides armatus.

Potential Impacts Avoided by Deletion of this Subarea:

Regional water quality impacts will not be significantly reduced.

Deletion of this area would avoid the almost negligible potential impacts in the area. Impacts to the benthic communities, the most likely faunal constituent to experience any impact, would be eliminated.






Planning Area: South Atlantic Planning Area

Subarea Name: Within 50 Statute miles from Coastline (North Carolina to Florida)

Deferral Recommended by: Natural Resources Defense Council, Greenpeace

Geographic Description:

This candidate encompasses 3,782 blocks and covers an area of 8,344,453 hectares (20,619,142 acres). This area would include all the blocks on the continental shelf that lie within 80 km (50 mi) of the coastline between North Carolina and northern Florida above 28° 17' 10" N latitude.

Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

Within 50 statue miles from coastline in south Atlantic:

° Not studied as an alternative at the EIS stage
° Blocks offered in Sales 43 (3/78) 7 leased, 56 (8/81) 28 leased, and 78 (7/83) 9 leased

Oil and Gas Resource Potential:

This subarea is located in less than 100 m (328 ft) of water in most of the planning area except off North Carolina where it extends out to 3,000 m (9,840 ft), and off north central Florida where it extends out to 500 m (1,640 ft).

Data coverage is generally sparse over this subarea except in localized areas off the Georgia-Florida border, Cape Romain, and north of Cape Lookout, where coverage is sufficient to define specific prospects.

The sedimentary section is thin (less than 3,049 m; 10,000 ft) in a large part of the subarea except in the northern portion (off North Carolina) where a part of the Carolina Trough sedimentary basin (an area of thick sediment accumulation that, locally, may exceed 10,670 m; 35,000 ft) lies within this option.

This subarea contains a trend of structural traps extending northeastward from the Southeast Georgia Embayment. Triassic rift-basins also occur within this subarea. In the northern part of the subarea (off North Carolina), this deferral option contains structural and stratigraphic traps associated with the Jurassic-Cretaceous carbonate paleo-shelf-edge trend.

Industry interest in this subarea (based on Sale 90 Area Identification is low. The resource potential of most of the subarea is still partly unknown due to a lack of data, but overall is considered

Within 50 Statute Miles from Coastline (North Carolina to Florida) (Continued)

low to moderate. In the northern part of the deferral option area (off North Carolina) where the carbonate paleo-shelf-edge and associated structural and stratigraphic traps are located, the resource potential is considered moderate to high.

No wells have been drilled within the area of this deferral alternative, and the most recent geophysical exploration activity occurred in 1982.

Description of the Environment:

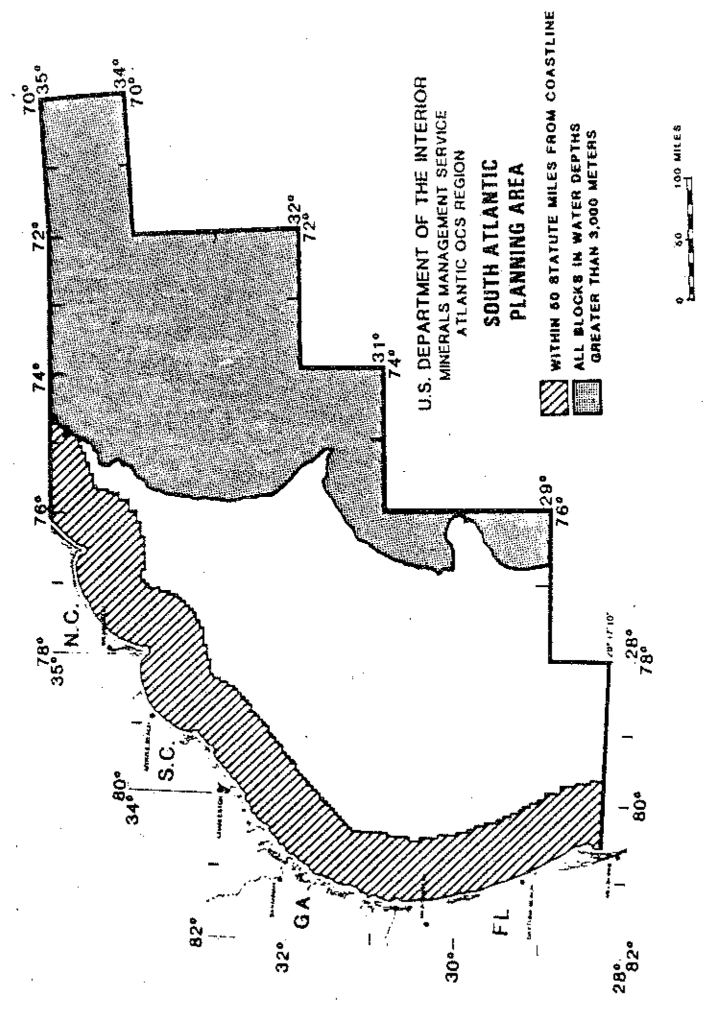
This subarea deferral alternative consists of low-relief and moderate-relief live bottoms connected by flat, soft-sand areas. The predominant taxa in the soft-sand habitat is Echinodermata, while the live-bottom areas are typified by a number of attached epifaunal species with their associated communities of biota (primarily polychaetes and amphipods). This subarea is the preferred habitat for the endangered Atlantic ridley turtle and the threatened loggerhead and green sea turtles. The endangered leatherback turtle may be found in the more offshore portion of this subarea. The right whale is reported to use the shallow, coastal area of the south Atlantic region as a calving area, and may be located in this subarea during the winter months. Commercial fisheries are prevalent throughout this subarea and recreational fishing can be found around the live-bottom areas which provide habitat for a number of reefal species of fish. The shrimp fishery is especially important in the near-shore portion of this subarea. The southernmost portion of this deferral area contains part of the only known scleractinian coral banks in the continental United States. This area provides a unique reefal habitat for a number of species associated with this ecosystem.

Potential Impacts Avoided by Deferral of this Subarea:

Deferral of this subarea would eliminate all potential for onshore visual impacts resulting from drilling structures. The impacts on commercial fisheries would be reduced as a result of the elimination of some competition for space between fisheries and oil and gas operations. However, the overall impact level on a regional level would not change. Direct impacts on endangered or threatened individuals would be reduced, but impacts on the population level would not be appreciably lessened, except for the endangered right whale. The impact level for the right whale population would be substantially reduced as a result of this deferral. Selection of this deferral alternative is not expected to reduce the regional impact levels anticipated for water quality, air quality, and coastal recreation areas.

Impacts on local water quality may be reduced through elimination of oil and gas related contaminants being directly introduced into the area.





Planning Area: South Atlantic Planning Area

Subarea Name: Nearshore/Low Potential Block Deferral

Deferral Recommended by: Environmental Protection Agency; National Oceanic and Atmospheric Administration; State of Georgia, State of Florida; Brevard County; Murphy Oil USA; Friends of Canaveral; Sierra Club (Florida Chapter) Natural Resources Defense Council; National Audubon Society (Florida Office)

Geographic Description:

This candidate encompasses 2,278 blocks and covers an area of 4,905,216 hectares (12,120,780 acres). It consists of the area on the continental shelf shoreward of a line that runs northeast-southwest from the planning area boundary in the north 30 km (18 mi) south of Cape Hatteras, North Carolina, to the planning area boundary in the south 86 km (55 mi) southeast of Cape Canaveral, Florida.

Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

Nearshore Block Deferral:

° Not studied as an Alternative at the EIS stage
° Blocks offered in Sale 56 (8/81)

Oil and Gas Resource Potential:

This subarea is located on the inner continental shelf in less than 40 m (131 ft) of water.

Data coverage is generally sparse to nonexistent except in localized areas off the Georgia-Florida border, Cape Romain, and Cape Lookout, where coverage is sufficient to define specific prospects.

The sedimentary section in this subarea is very thin (less than 3,049 m; 10,000 ft) but it does increase locally in the presence of Triassic rift-basins, which occur along this part of the inner shelf. Structural traps have yet to be identified in this subarea; however, there are several small anticlinal structures that trend northeastward from the Southeast Georgia Embayment along the seaward boundary of the subarea.

Industry interest in this subarea (based on Sale 90 Area Identification is low, and the resource potential, though largely unknown due to a lack of data, is considered low overall.

No wells have been drilled within the area of this deferral alternative, and the most recent geophysical exploration activity occurred in 1980.



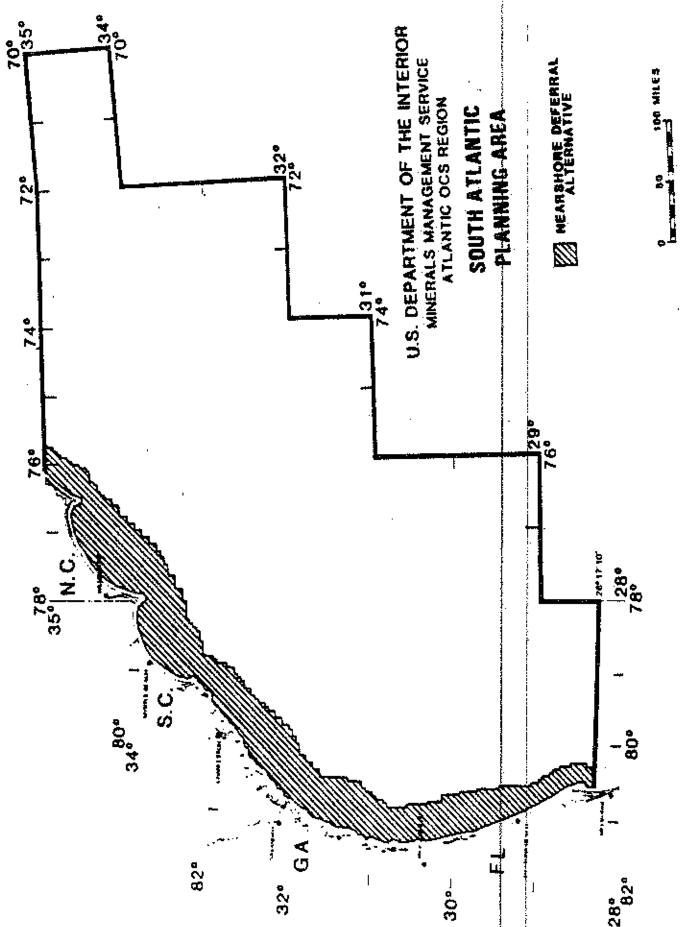
Nearshore/Low Potential Block Deferral (Continued)

Description of the Environment:

This subarea consists primarily of sand bottoms interspersed with exposed hard-substrate areas which are colonized by various epibenthic species, such as sponges and soft corals. These live-bottom areas are typically low-relief expanses of attached species with their associated biota (e.g., amphipods and polychaetes) and may be susceptible to periodic inundation by sand veneers. The seaward edge of the subarea contains moderate-relief live bottoms, which are usually found between the 30 m and 60 m (98 and 197 ft) isobaths. The sand bottoms contain many taxa of infaunal and epifaunal organisms, with echinoderms being most commonly observed. These shallow waters are the preferred habitat for the endangered Atlantic ridley turtle and the threatened loggerhead and green sea turtles. The endangered right whale is reported to use the shallow, coastal area of the south Atlantic region as a calving area, and may be located in this subarea during the winter months. Commercial fisheries are prevalent throughout this subarea and recreational fishing is on the increase around the live-bottom areas which provide habitat for a number of reefal species of fish. The shrimp fishery is especially important in the near-shore portion of this subarea.

Potential Impacts Avoided by Deferral of this Subarea:

Selection of this deferral alternative is not expected to reduce the regional impact levels anticipated for water quality, air quality, and coastal recreation areas. The impacts on commercial fisheries would be slightly reduced as a result of the elimination of some competition for space between fisheries and oil and gas operations. However, the overall impact level would not change. Direct impacts on endangered or threatened individuals would be reduced, but impacts on the population level would not be appreciably lessened, except for the right whale which would have a substantial reduction in the estimated impact level. Deferral of this subarea would eliminate all potential for onshore visual impacts resulting from drilling structures.






Planning Area: Straits of Florida Planning Area

- Subarea Name: Atlantic Coast of the Straits of Florida

Deferral Recommended by: Environmental Protection Agency, State of Florida, Brevard County, City of Key West, Chevron, Natural Resources Defense Council, Sierra Club (Florida Chapter), Senator Lawton Chiles, Murphy Oil USA, National Audubon Society (Florida Chapter)

Geographic Description:

This candidate encompasses 1,010 blocks and covers an area of 2,079,360 hectares (5,138,099 acres). This area would include all the blocks in the Straits of Florida north of 25° 7'N Latitude, which is essentially the whole shelf from Key Largo to Cape Canaveral.

Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

Atlantic Coast of Straits of Florida:

° Not studied as an Alternative at the EIS stage

Oil and Gas Resource Potential:

This deferral option overlies the southwest flank of the Blake Plateau sedimentary basin in its northern part and the northeast flank of the South Florida-Bahama sedimentary basin in its southern part. Areally, both basins are the largest that occur beneath the U.S. Atlantic continental margin and, locally, may contain up to 10,670 m (35,000 ft) of post-Triassic age sediments overlying an unknown thickness of Triassic age, rift-stage sedimentary rocks. These basins are separated beneath the central part of the subarea by the Peninsula Arch - a major regional, southeast trending and plunging, pre-Triassic basement ridge.

Existing data coverage in the northern part of the subarea is sufficient to define major structural trends and, in some places, to define specific prospects. In the southern part, coverage is very sparse to absent.

Atlantic Coast Straits of Florida (Continued)

A few structures have been identified within the subarea and additional structural and/or stratigraphic traps may occur locally in association with block-faulted basement features.

The resource potential of this subarea of unknown industry interest is presently considered low nearshore, and moderate further offshore.

No industry wells have been drilled in this subarea and the latest industry geophysical exploration activity occurred in 1983.

Description of the Environment:

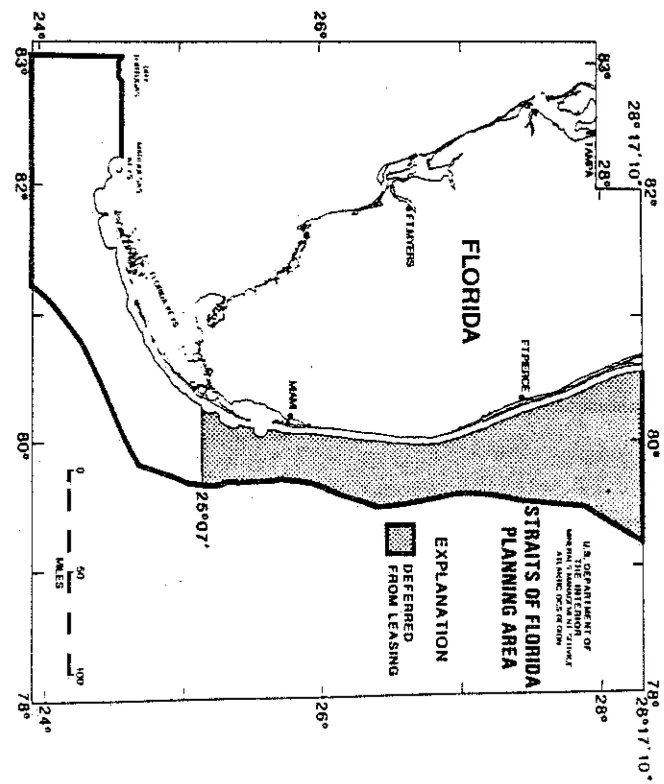
This subarea deferral alternative consists of fine sandy areas graduating seaward to coarser grains, interspersed with patches of low, moderate, and high-relief live bottoms. This area contains the northern edge of the only known Oculina reef off the continental United States. The live-bottoms support a diverse group of commerically, ecologically, and recreationally important fish species.

Potential Impacts Avoided by Deferral of this Subarea:

Deferral of this area would eliminate impacts to the local communities from the placement of drilling platforms, drilling discharges, and oil spills. Impacts to important habitat areas for brown pelicans and manatees, which border the west side of the deferred area would be limited and reduced. Impacts to recreational, economic, and biological resources within the deferred area would be eliminated.

Deferral of this area would reduce the risk of oil and gas related contaminants being spilled shoreward of the Gulf Stream or being directly incorporated into the Gulf Stream and then carried shoreward by eddies, thus reducing local impact on water quality. The regional impact on water quality, however, would not be significantly reduced.





Planning Area: Straits of Florida Planning Area

Subarea Name: Looe Key and Key Largo Marine Sanctuary Deferral

Deferral Recommended by: Florida Defenders of the Environment, Congressman Dante B. Fascell

Geographic Description:

This candidate is comprised of two marine sanctuaries located in the Straits of Florida adjacent to the Florida Keys. The first is Looe Key National Marine Sanctuary, located 12.4 km (7.7 mi) southwest of Big Pine Key, Florida. It encompasses 2 blocks and covers an area of 3,456 hectares (8,538 acres). It is bounded by the following coordinates:

| | |
|---|---|
| 24° 31.37' N | 81° 26.00' W |
| 24° 33.34' N | 81° 26.00' W |
| 24° 34.09' N | 81° 23.00' W |
| 24° 32.12' N | 81° 23.00' W |

The second is Key Largo National Marine Sanctuary, which extends from the State territorial water boundary seaward to the 91 m (300 ft) isobath, encompassing 25 blocks and covering an area of 41,471 hectares (102,477 acres) off Key Largo, Florida. The marine sanctuary is bounded by the following coordinates:

| | |
|---|---|
| 25° 19.45' N | 80° 12.00' W |
| 25° 16.20' N | 80° 08.70' W |
| 25° 07.50' N | 80° 12.50' W |
| 24° 58.30' N | 80° 25.25' W |
| 25° 02.20' N | 80° 25.25' W |

Sales (and dates held) for which the Subarea was Studied and Disposition in Each Sale:

Looe Key and Key Largo Marine Sanctuaries:

° Not studied as an Alternative at the EIS stage

Oil and Gas Resource Potential:

The Looe Key deferral option is situated near the axis of the South Florida-Bahama sedimentary basin where up to 10,670 m (35,000 ft) of Jurassic and younger age sediments are found to overlie an unknown thickness of Triassic rift-stage deposits. Specifically, the option occurs over Pine Key Arch - a deep, low relief, basement anticlinal structure postulated to underlie, on trend, the entire Florida Keys chain of islands.



Looe Key and Key Largo National Marine Sanctuary (Continued)

The Key Largo deferral option is associated with the northern part of the South Florida-Bahama sedimentary basin where up to 10,670 m (35,000 ft) of Jurassic and younger age sediments overlie an unknown thickness of Triassic age rift-stage deposits.

Specifically, as with the Looe Key deferral subarea, it occurs atop the Pine Key Arch - a deep, low relief, anticlinal basement feature that trends westward along the Florida Keys.

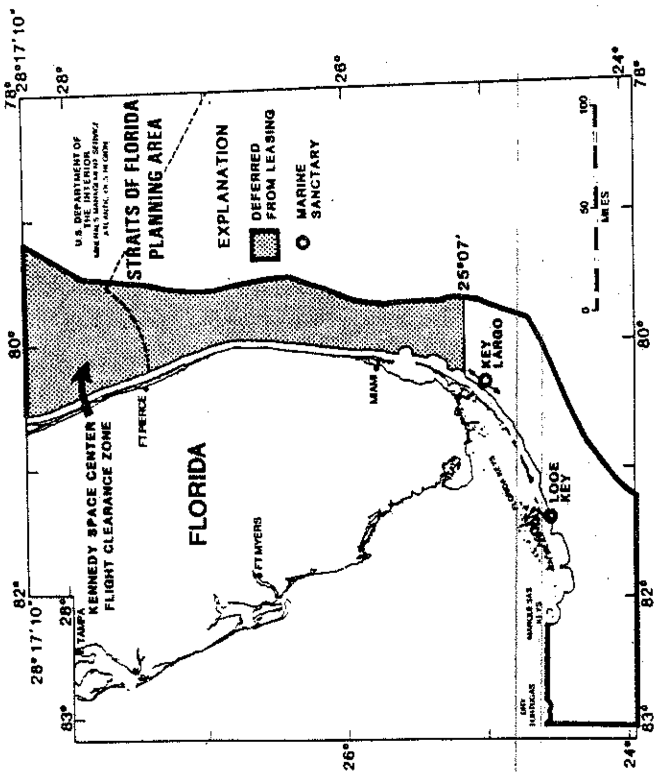
No data coverage exists in these marine sanctuary deferral subareas, and no industry wells have been drilled in these subareas; however, they are located in areas considered to be of high resource potential due to nearby production associated with the "Sunniland Trend" of south Florida and production along the north coast of Cuba. In addition, hydrocarbon shows were encountered in wells drilled just west of the subarea in the vicinity of the Marqueses Keys.

Description of the Environment:

This subarea contains the only living tropical coral reef in the waters of the continental United States. The sanctuaries are shallow-water areas with important recreational, ecological, and aesthetic resources. Dominant fauna of the area includes many species of reef fish which are associated with coral reef areas in the tropical regions of the western hemisphere. These reef areas are typical of all coral reefs in that the overall complexity of the coral growth provides numerous niches for a variety of organisms including mollusks, echinoderms, polychaetes, amphipods, crustaceans, and fish.

Potential Impacts Avoided by Deferral of this Subarea:

Deferral of this subarea will eliminate the direct impacts to the marine sanctuaries which would occur if oil and gas activities were allowed in the area. However, those impacts that may occur from drilling activities in proximity to the sanctuaries (drilling discharges) would not be eliminated. In addition, the potential impacts which may result from an oil spill would remain the same. Therefore, no reduction in the overall impact levels for any of the analyzed resources would be expected.






Planning Area

Eastern Planning Area - Gulf of Mexico

Subarea Name

Twenty Meter-Thirty Mile Subarea.

a. Deferral Recommended by:

State of Florida.

b. Geographic Description:

This deferral represents a by-block-line description of the 20 m - 30 mile demarcation from the Florida coast. It extends from Apalachicola on the north to the State-Federal boundary along the Florida Keys. This deferral is comprised of 1520 blocks and 8,046,405.15 acres.

c. Sales (and date held) for which the Subarea was studied and Disposition in Each Sale.

That part of this deferral area within the Miami Map Area has never been included in the Eastern Planning Area and has never been offered for sale. That area south of 25°N and east of 82°W has not been offered for sale.

The balance of this deferral area was deferred from Sale 79 (January 1984) and Sale 94 (November 1985).

d. Oil and Gas Resource Potential:

1. Industry interest has centered around the Destin Dome area and the Florida Panhandle to the north.

2. There has been little exploratory drilling activity in the twenty meter - thirty mile subarea. The latest geological and geophysical permit (M 86-3) was approved May 1, 1986 for the Eastern Planning Area.

3. Numerous structures have been identified within the Buffer Zone but no prospects and stratigraphic traps have been identified.

4. The 30-mile Buffer Zone is covered by a regional seismic survey. Locally denser grids are available. Wells have been drilled in the Destin Dome area and fields exist in the Florida Panhandle to the north. Several wells have been drilled offshore west of Tampa.

5. Potential exploration trends in the Destin Dome area are in the Upper Jurassic. The rest of the arch to the south lies within a probable Cretaceous trend.

6. The area in the north has a high to moderate potential for oil. The area in the south has a moderate oil potential and a low gas potential.

e. Description of the Environment:

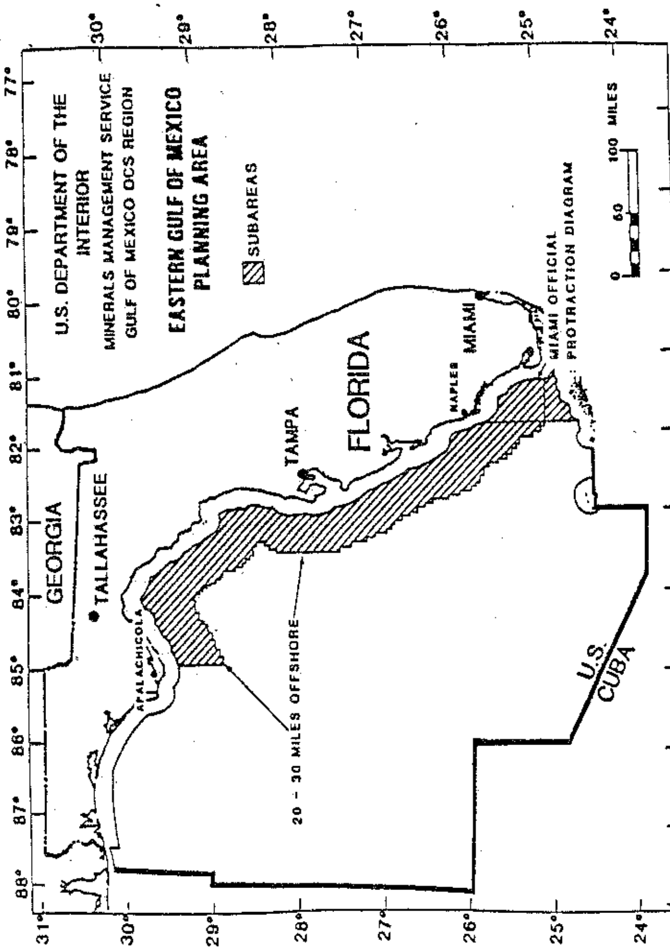
The coastal areas encompass a wide variety of habitats, including seagrass beds, salt marshes, fresh marshes, mangroves, barrier beaches, estuaries, and coral reefs. The estuaries and marshes are very important in the production of commercially and recreationally important fish and wildlife species. The Florida beaches are important storm protection and erosion control areas. The Florida tourism industry is based on the presence of these beaches. The seagrass beds support numerous and commercially and recreationally important fishery and wildlife species.

Along the southern extent of this subarea lies the ecosystem associated with the Florida Keys. Live bottoms communities consisting of algae,ascidians, hard corals, gorgonians, hydrozoans, and sponges, can be expected throughout this area. The subarea is offshore of the Everglades National Park, extensive stands of mangroves, and freshwater marsh. This entire adjacent coastal area is a sensitive and valuable national resource. The subarea lies in proximity to vast amount of seagrass beds, mangroves, and marshes. The coastal and offshore area supports a number of coastal/marine birds and endangered species including the manatee, key deer, and numerous sea turtle nesting areas.

f. <u>Potential Impacts Avoided by Deferral of this Subarea</u>:

Deferral of this subarea would preclude drilling operations within the subarea and greatly decrease or eliminate the threat of damage from oil spills, drilling discharges, anchoring, or platform emplacement from such areas in the areas removed. The deferral of this subarea would protect live bottom communities from impacts due to oil and gas activities within the subarea. Oil spills due to MMS permitted activities would not originate in this area. Consequently, impacts to sensitive and valuable coastal habitats, coastal/marine birds, and endangered species may be avoided by deletion of this subarea.





Planning Area

Eastern Planning Area - Gulf of Mexico

Subarea Name

Apalachicola to Panama City Extension.

a. Deferral Recommended by:

State of Florida.

b. Geographic Description:

From approximately 85°53' and 30°02' southeasterly to approximately 85°17' and 29°24' and approximately 20 statute miles offshore thence southerly to approximately 85°17' and 29°05' thence easterly to approximately 84°54' and 29°03' thence northerly to 84°53' and 29°29'. Comprising approximately 132 blocks and 659,479.41 acres.

c. Sales (and date held) for which the Subarea was studied and Disposition in Each Sale.

This deferral is a slight modification to a deferral in Sales 79 and 94 that was an area similar and slightly larger.

d. Oil and Gas Resource Potential:

1. Recent industry interest in parts of this area has been substantial.
2. There has been no recent exploratory drilling activity in this area. The most recent geological and geophysical permit (M 86-11) was approved August 6, 1986 for this subarea.
3. Structures have been identified, but prospects and stratigraphic traps have not been identified.
4. The area is covered by regional seismic survey and regional maps.
5. Exploration trends within the area are most likely Cretaceous.
6. Part of this area has a low potential for oil and gas resources. Another part has a much more favorable potential.

e. Description of the Environment:

Although the specific extent and position of live bottoms within the area is unknown, significant areas of the Eastern Gulf of Mexico are scattered with live bottom communities comprised of sponges, octocorals, gorgonians, and a few hard corals.

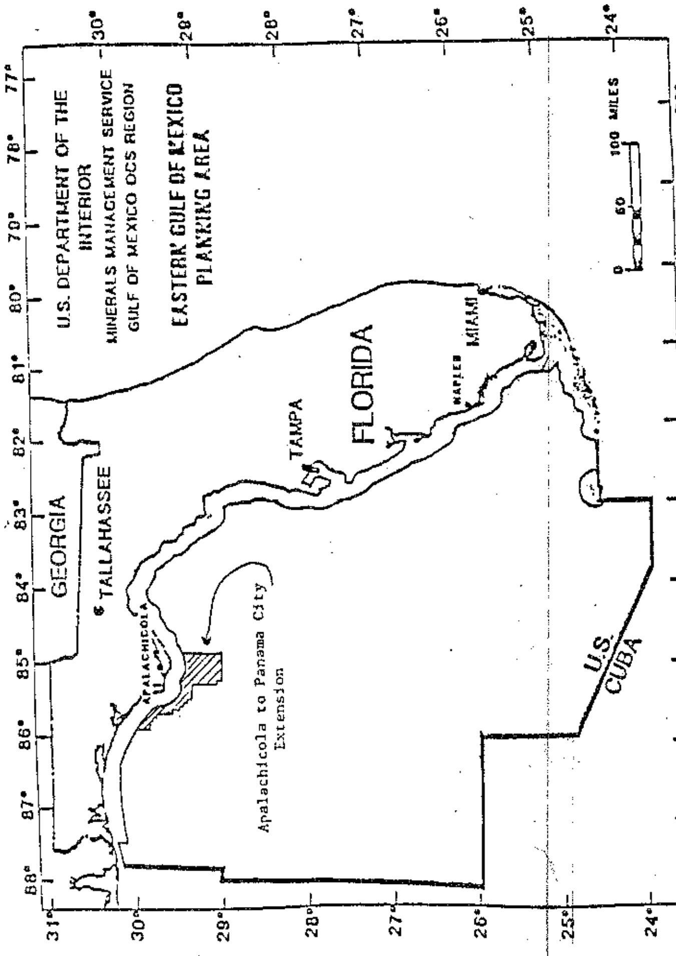
The coastal areas encompass a wide variety of habitats, including seagrass beds, salt marshes, fresh marshes, mangroves, barrier beaches, estuaries, and coral reefs. The estuaries and marshes are very important in the production of commercially and recreationally important fish and wildlife species. The Florida barrier islands are important storm protection and erosion control areas for the mainland beaches, wetlands and mangroves.



The coastal area is distinguished by the presence of two productive estuaries, St. Andrew Bay and Apalachicola Bay. St. Andrew Bay contains lush seagrass beds and is important to commercial and recreational fisheries and to the tourism industry. Apalachicola Bay and surrounding area is noted for its commercial oyster fishery and and as a breeding area for the blue crab. The bay has been designated a National Estuarine Sanctuary. St. Vincent Island, one of the barrier islands to the bay, is a National Wildlife Refuge.

f. Potential Impacts Avoided by Deferral of this Subarea:

Deferral of this subarea would preclude drilling operations within the subarea and so eliminate the threat of damage from oil spills, drilling discharges, anchoring, or platform emplacement from such operations in the areas removed. The deferral of this subarea would protect live bottom communities from impacts due to oil and gas activities within the subarea. Oil spills due to MMS permitted activities would not originate in this area. Although the potential for oil spills is low, the potential impact is significant. Deferral of this subarea would eliminate the potential for oil and gas leasing activity caused oil spills from occurring in the subarea thereby allowing additional time for oil spill cleanup, containment or dispersion, and weathering before contact with the shore and sensitive coastal habitats. Some impacts to sensitive and valuable coastal habitats, coastal/marine birds, and endangered species may be avoided by deletion of this subarea.






Planning Area

Eastern Planning Area - Gulf of Mexico

Subarea Name

South of 25°N, 82°W Subarea (North and West of the Florida Keys).

a. Deferral Recommended by:

South Florida Regional Planning Council.

b. Geographic Description:

This deferral included a 30 mile zone on the western flank of the Dry Tortugas and is bounded on the north of the 25°N latitude. The southern extent of the area runs easterly from 83°W and 24°35'N to the state/federal boundary along the Florida Keys to 81°55'N thence northly to 25°N. This deferral is comprised of 320 blocks and 1,706,218.00 acres.

c. Sales (and date held) for which the Subarea was studied and Disposition in Each Sale.

We have not studied this particular area in any previous sale document. This area has not been offered for lease.

d. Oil and Gas Resource Potential:

1. Industry interest has recently been expressed in this area. Until recently this area had not been available for nominations.

2. There have been no recent exploratory drilling activity in this area. The latest geological and geophysical permit in this area was (M 86-10) approved July 11, 1986.

3. Regional structural trends are shown. No prospects on stratigraphic traps have been identified in this area.

4. Limited regional seismic coverage of questionable data quality exists.

5. Exploration targets would be the Cretaceous and possibly the Jurassic.

6. The area has moderate oil potential and low gas potential.

e. Description of the Environment:

The subarea is directly north and west of the extremely sensitive and valuable resources of the Western Florida Keys and the Dry Tortuges.. The habitats of this area include the live bottom communities, coral reefs, mangroves, and seagrass beds. Numerous coastal/marine birds and rare and endangered species inhabit this area. The nearby coastal area contains, among other State and private designations, three National Wildlife Refuges, and a National Monument.

Live bottom communities consisting of algae, ascidians, hard corals, gorgonians, hydrozoans, and sponges can be expected, scattered throughout the subarea.

Coral reefs are highly complex and diverse communities. Many important fisheries are directly tied to the coral reef. Coral reefs also support a significant portion of the tourist industry of

Florida. Coral reefs are located in State waters surrounded by the ... etion alte... e, and also within Federal OCS waters between Key West and the Dr...

The mangrove community is composed of four species: the red, black and white mangroves, and buttonwood. The community is zoned generally from the red mangroves in the submerged land at the water's edge, through the intertidal zone inhabited by black mangrove, to buttonwood and white mangroves on higher ground. Mangroves produce large amount of detrital material which is contributed to the surrounding ecosystem. Numerous small fish and invertebrates use the mangrove environment, especially the prop roots of the red mangroves, for feeding and refuge. Birds such as herons and spoonbills use the mangrove islands as rookeries due to their relatively inaccessible nature and proximity to feeding areas. Mangroves serve as shoreline erosion protection and as substrate builder by trapping and stabilizing intertidal sediments and debris.

Seagrasses in the area are comprised predominantly of Thalassia testudinum, Syringodium filiforme, Halophila spp., and Halodule wrightii. These seagrass beds are important to the overall ecology of the Eastern Gulf of Mexico, and support numerous commercially and recreationally important fishery and wildlife species.

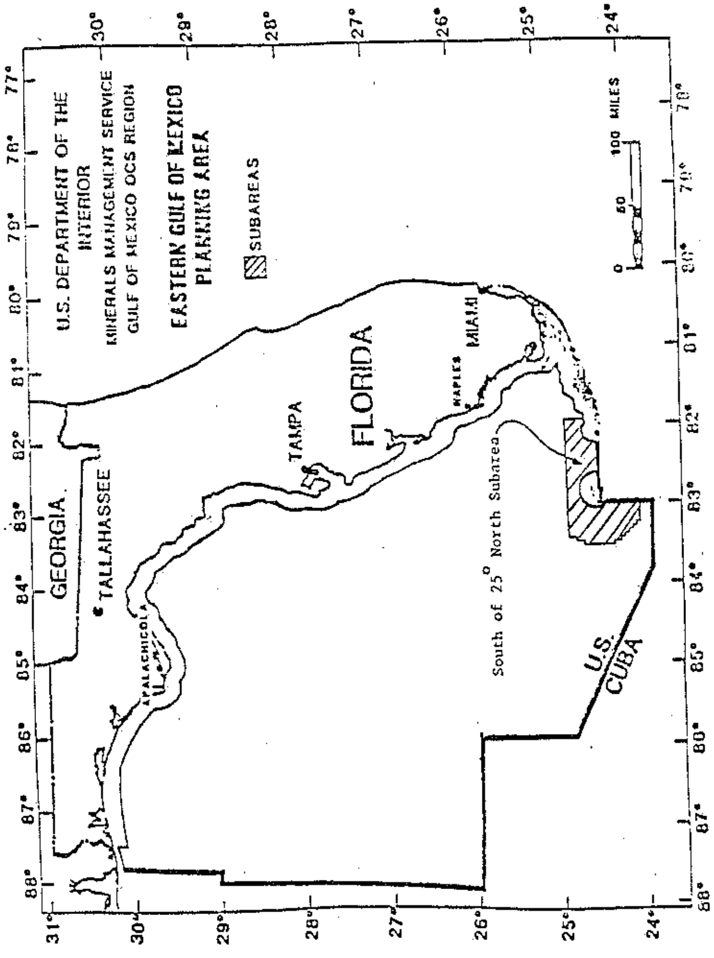
Coastal birds of the area include, herons, egrets, ibis, spoonbills, ospreys, and pelicans. Rare species which inhabit this area include the Federally endangered key deer and loggerhead turtles.

f. Potential Impacts Avoided by Deferral of this Subarea:

The major potential impact producing factors that could affect sensitive offshore habitats in this area are mechanical damage due to anchors, drilling, pipelines, and platform emplacement and drilling discharges. These impact producing factors, with the exception of pipeline emplacement, would be considerably reduced by implementation of protective stipulations in this area. These protective stipulations will reduce potentially high impacts from activites within the subarea to live bottom communities, coral reefs, and seagrasses; to the recreational and commercial fisheries of the area; and to the intrinsic biological, ecological, and aesthetic values of these areas. Deferral of this subarea would also reduce potentially high impacts to those sensitive environmental areas discussed above.

Deletion of the subarea would preclude the impacts due to oil spills originating within the subarea to the offshore habitats within the subarea and add a buffer of approximately 20 miles to the extremely sensitive coastal habitat. Potentially severe oil spill impacts resulting from a spill adjacent to coral reefs or seagrass beds would be avoided. Deletion of this subarea may prevent significant impact to the coral reefs, mangroves, and endangered species habitats of the Florida Keys by increasing the distance from which an oil spill could occur, thus allowing additional time for clean-up, dispersion, and weathering of the oil. The extent and effect of this additional time in reducing impacts to resources has not been analyzed in any previous sale document.





Planning Area

Eastern Planning Area - Gulf of Mexico

Subarea Name

Fifty Mile Buffer Zone Off Florida.

a. Deferral Recommended by:

Florida Department of Natural Resources.

b. Geographic Description:

The 50-mile buffer zone in the Eastern Gulf of Mexico included approximately 30 percent of the Eastern Planning Area (23 million acres) lying offshore Escambia to Monroe Counties. It extends approximately westward from longitude 81°W to longitude 87°45'W and southward from latitude 30°15'N latitude 24°45'N. Water depths range up to 600 meters.

c. Sales (and date held) for which the Subarea was studied and Disposition in Each Sale.

Because the area south of latitude 25°N has previously not been included in the Eastern Planning Area, that portion of the 50-mile buffer alternative which surrounds the Florida Keys and Dry Tortugas was not available for lease. Areas north of 25°N latitude such as the seagrass beds, and the area within 30 miles of the coast have been deferred from earlier sales. Areas within the 50-mile buffer have also been offered and active leases exist. We have not studied this particular subarea in any previous sale document.

d. Oil and Gas Resource Potential:

1. Industry interest has centered around the Destin Dome area.
2. There has been some scattered exploratory drilling activity in the Fifty mile buffer zone but no areas have yet been found to be economically producable. The latest geological and geophysical permit (M 86-3) was approved May 1, 1986 for the Eastern Gulf.
3. Numerous structures have been identified within the Buffer Zone but no prospects and stratigraphic traps have been identified.
4. The 50-mile Buffer Zone is covered by a regional seismic survey. Locally denser grids are available. Wells have been drilled in the Destin Dome area and fields exist in the Florida Panhandle to the north. Several wells have been drilled offshore west of Tampa.
5. Potential exploration trends in the Destin Dome area are in the Upper Jurassic. The rest of the arch to the south lies within a probable Cretaceous trend.
6. The area in the north has a high to moderate potential for oil. The area in the south has a moderate oil potential and a low gas potential.

e. Description of the Environment:

This subarea includes the entire area discussed in the 30-mile buffer zone deferral and extends this area an additional 20 miles offshore.



Within the subarea are extremely sensitive and valuable habitats including coral reefs, mangroves, and seagrass beds. Numerous coastal/marine birds and rare and endangered species inhabit this area.

Coral reefs are highly complex and diverse communities. Many important fisheries are directly tied to the coral reef. Coral reefs also support a significant portion of the tourist industry of Florida. Coral reefs are located in State waters surrounded by the deletion alternative, and also within Federal OCS waters between Key West and the Dry Tortugas.

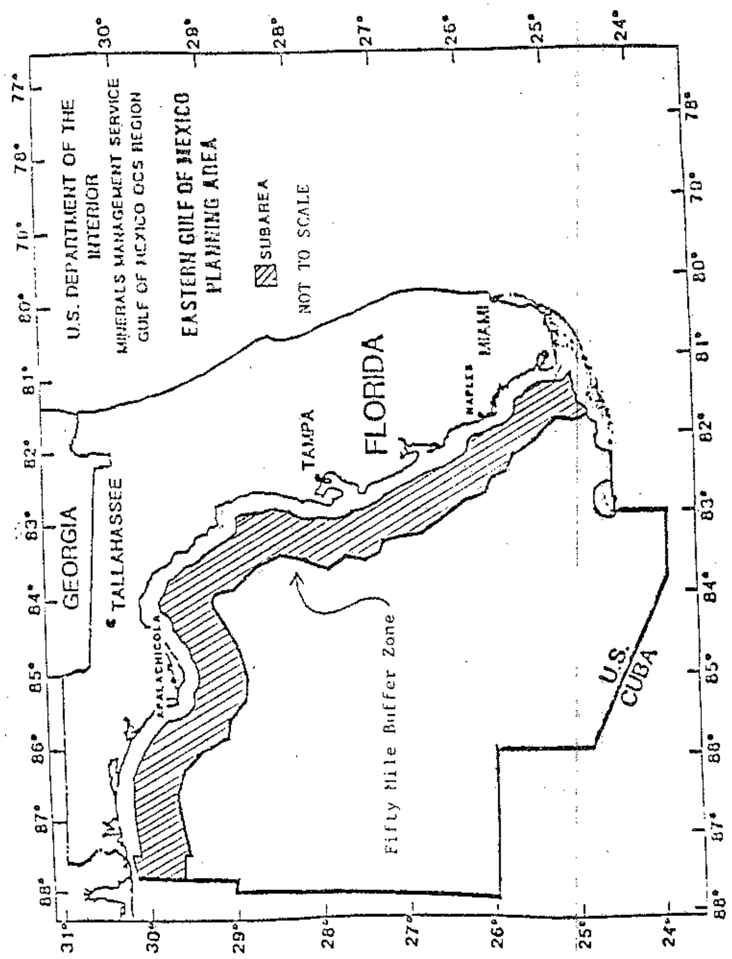
The mangrove community is composed of four species: the red, black and white mangroves, and buttonwood. The community is zoned generally from the red mangroves in the submerged land at the water's edge, through the intertidal zone inhabited by black mangrove, buttonwood and white mangroves on higher ground. Mangroves produce large amount of detrital material which is contributed to the surrounding ecosystem. Numerous small fish and invertebrates use the mangrove environment, especially the prop roots of the red mangroves, for feeding and refuge. Birds such as herons and spoonbills use the mangrove islands as rookeries due to their relatively inaccessible nature and proximity to feeding areas. Mangroves serve as shoreline erosion protection and as substrate builder by trapping and stabilizing intertidal sediments and debris.

Seagrasses in the area are discussed in several other deferral areas which are part of this large deferral area.

Coastal birds of the area include, herons, egrets, ibis, spoonbills, ospreys, and pelicans. Rare species which inhabit this area include the Federally endangered key deer and loggerhead turtles.

f. Potential Impacts Avoided by Deferral of this Subarea:

The major potential impact producing factor would be oil spill damage to sensitive coral reefs, seagrass beds, recreational beaches, and to sensitive mangroves and wetlands that would have long term and irreparable impacts on the intrinsic biological, ecological and aesthetic values of this area. If this unlikely event occurred it could seriously affect the tourism and retirement based economy that is primary to this region. Other potential impact producing factors that could affect sensitive offshore habitats in the Eastern Gulf of Mexico are mechanical damage due to anchors, drilling, pipelines, and platform emplacement, as well as smothering effects from drilling discharges. These impact producing factors, with the exception of pipeline emplacement, would be eliminated from the subarea. Elimination of these impact producing factors would preclude potentially high impacts to live bottom communities; to the recreational and commercial fisheries of the area; and to the intrinsic biological, ecological, and aesthetic values of these areas.






Planning Area

Eastern Planning Area - Gulf of Mexico

Subarea Name

South of Latitude 26oN

a. Deferral Recommended by:

South Florida Regional Planning Council

b. Geographic Description:

The area south of latitude 26oN ranges from that latitude to latitude 24oN and east from longitude 85oW to longitude 81oW. The area consists of approximately 19.1 million acres in the Eastern Gulf of Mexico and extends southward from 9-308 miles offshore in water depths ranging between 10-3,200 meters.

c. Sales (and date held) for which the Subarea was studied and Disposition in Each Sale.

The area south of latitude 25oN has not previously been included in the Eastern Planning Area and, therefore, has never been offered for lease. The portion of the subarea between latitude 26oN and latitude 25oN is discussed below.

Sale 79 (January 1984) - The area between latitude 26oN and latitude 25oN was discussed in the EIS as a deletion alternative. This area was not deferred from the sale.

Sale 94 (November 1985) - The area between latitude 26oN and latitude 25oN were discussed as a deletion alternative. This area was not deferred from the sale.

d. Oil and Gas Resource Potential:

1. Seventy four leases are active in this area and industry has not had a chance to drill these yet.

2. There have been no recent exploratory drilling activity in this area. The latest geological and geophysical permit in this area was (M 81-10) was approved July 11, 1986.

3. No structures, prospects, or stratigraphic traps have been identified within this area.

4. There is limited regional seismic coverage.

5. Possible exploration targets would be the Cretaceous, possibly the Jurassic.

6. The area has moderate oil potential and a low gas potential.

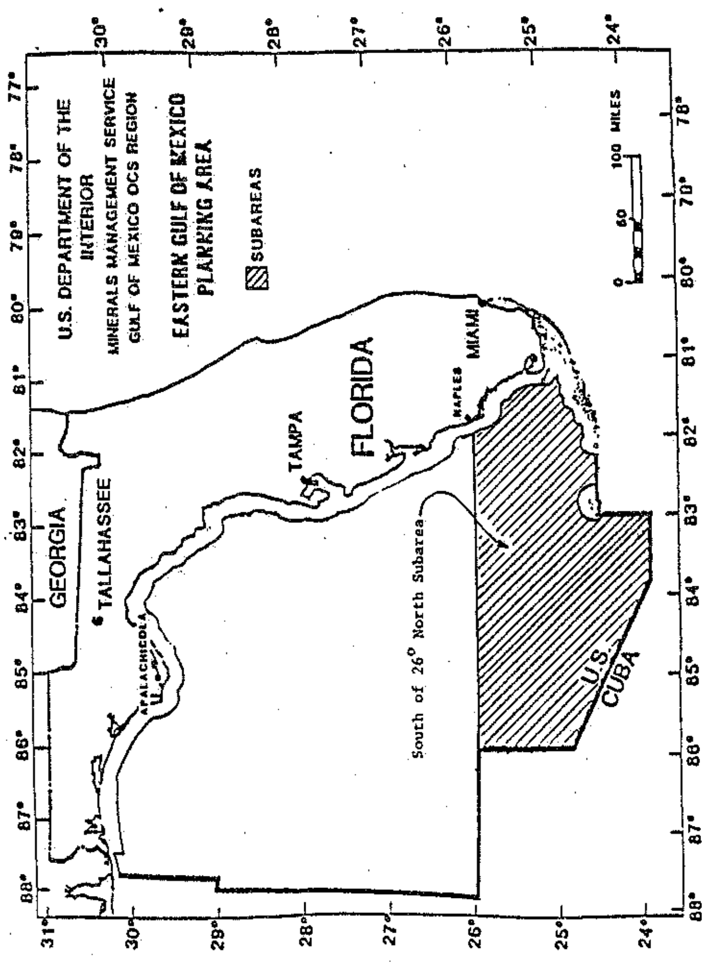
e. Description of the Environment:

This environment is described in the environmental descriptions contained in the deferral descriptions for South of 25oN and the 50 Mile Buffer Zone. These descriptions combine to describe the area surrounding and between the Florida Keys, the Dry Tortugas and along the coast of Florida South of latitude 26oN.

f. Potential Impacts Avoided by Deferral of this Subarea:

Adoption of this deferral would ensure that significant live bottom communities, seagrass beds, and coral reefs within the subarea would be protected from physical disturbance associated with oil and gas operations, such as those caused by anchor and drilling vessel placement, and smothering from drilling cuttings discharges. Adoption would also ensure that an oil spill would not originate on these blocks. The coastal area described in the South of 25ºN subarea including the Florida Keys/Dry Tortugas would be buffered from potential spills occurring outside of the subarea allowing for more time for cleanup equipment and dispersant activities to take place before the spill reached sensitive environmental resources in this area. The effectiveness of this buffer has not been analyzed in any previous sale document.





Planning Area

Eastern Planning Area - Gulf of Mexico

Subarea Name

Florida Middle Ground

a. Deferral Recommended by:

Florida Department of Natural Resources

b. Geographic Description:

The Florida Middle Ground in the Eastern Gulf of Mexico includes 23 blocks and approximately 132,480 acres lying offshore Franklin County. It extends south from latitude 29ºN to latitude 28ºN and west from longitude 84ºW to longitude 85ºW. The Middle Ground extends up to 86 miles offshore Florida in water depths up to 40 meters.

c. Sales (and date held) for which the Subarea was studied and Disposition in Each Sale.

Sale 79 (January 1984) - The Florida Middle Ground was discussed in the EIS as a deletion alternative and was deferred from the sale.

Sale 94 (November 1985) - The Florida Middle Ground was deferred from the proposed action in the EIS.

d. Oil and Gas Resource Potential:

1. No recent interest by industry has been shown in this subarea.
2. No recent exploratory drilling or geological and geophysical surveying has occurred in this area.
3. Structures have been identified, but prospects and stratigraphic traps have not been identified.
4. There is regional seismic coverage in the area.
5. Exploration trends within the area are most likely Cretaceous.
6. The entire area has a low potential for oil and gas resources.

e. Description of the Environment:

The Florida Middle Ground is probably the best known and most biologically developed of the live bottom areas with extensive inhabitation by hermatypic corals and related communities. This area is 87 nmi (160 km) west-northwest of Tampa and has been designated as a Habitat Area of Particular Concern (HAPC) by the Gulf of Mexico Fishery Management Council. The taking of any corals is prohibited except as authorized by permit.



The Florida Middle Ground represents the northermost extent of coral reefs and their associated assemblages in the Eastern Gulf. The Middle Ground is like the Flower Garden Banks off Texas-typical Caribbean reefal communities although somewhat depauperate in terms of these types of coral communities.

Favorable environmental conditions associated with offshore distance and moderating currents allow occupation of the Middle Ground by numerous stenoecious fishes recruited from the Caribbean-West Indian region. Transparent waters, shallow reef crests, irregular bottom topography, well-defined currents, and carbonate sediments attract many insular reef fishes either rare or absent at other West Florida Shelf reefs. Environmental stability at the Middle Ground has undoubtedly enhanced development of its diverse fauna.

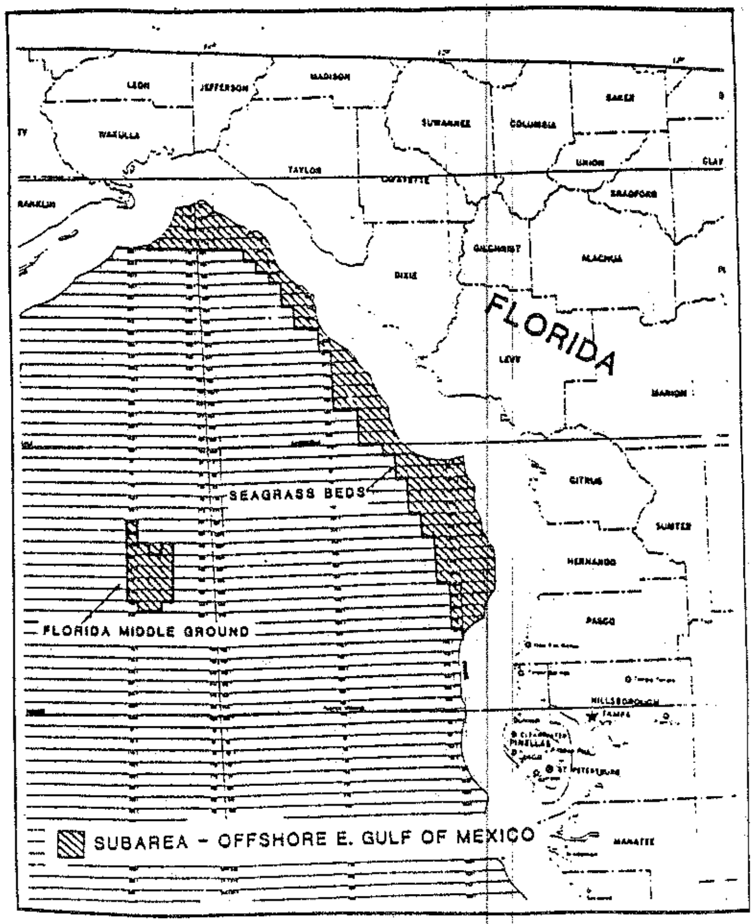
There are four dominant stony corals of the Florida Middle Ground hard banks. Octocorals, a relatively minor component of other Gulf reefs, are also prominent on the Middle Ground. Recreational activities are limited by the distance from shore. Despite the distance from the coast to the Florida Middle Ground, enthusiastic sport fisherman and recreational divers have been reported to frequent the area. The Middle Ground was nominated as a marine sanctuary and has been designated a habitate area of particular concern. This area is frequented by commercial fishing boats since the primary fish species involved include the red snapper and grouper, which dominate the landings and value of landings of Gulf reef fish.

f. Potential Impacts Avoided by Deferral of this Subarea:

As an alternative to deletion of this subarea, adoption of the biological stipulation would preclude impacts to the Florida Middle Ground as no activity (including anchoring) would be permitted within the sensitive portion of these blocks. Surface oil spills are not expected to be a threat to the Middle Ground since it crest at approximately 25m whereas surface oil can be expected to be driven 10m into the water column.

This alternative would defer the 23 blocks containing "No Activity Zone" areas of the Florida Middle Ground. Deferring this small percentage of the Eastern Gulf offering will result in a very large reduction of the potential impact to the high value biological resources.

The biological resources of the Middle Ground are considered very sensitive to potential impacts due to oil and gas operations. Deferral would remove the risks to the biological resources of the area from offshore operations on the 23 blocks.






Planning Area

Eastern Planning Area - Gulf of Mexico

Subarea Name

Offshore Seagrass Beds.

a. Deferral Recommended by:

South Florida Regional Planning Council.

b. Geographic Description:

This Eastern Gulf deletion candidate ranges south from latitude 30ºN to latitute 28ºN and west from longitude 82ºW to longitude 84ºW. This area consists of approximately 1.07 million acres lying offshore from Wakulla to Pasco Counties. It extends southeastward from 9 miles off the coast of Florida to approximately 25 miles offshore in water depths up to 10 meters.

c. Sales (and date held) for which the Subarea was studied and Disposition in Each Sale.

Sale 79 (January 1984) - The Seagrass beds were discussed as a deletion alternative in the EIS and were deferred from the sale.

Sale 94 (November 1985) - The Seagrass beds were deferred from the proposed action in March 1984 after being included in the moratorium.

The boundaries of this subarea have varied between the different deletion alternatives and deferrals.

d. Oil and Gas Resource Potential:

1. No industry interest has been shown in this area.

2. Only minor exploratory activity has been conducted in the area an too date no economically producable discoveries in the area have been made.
3. No structures have been identified in this area.

4. Some regional seismic coverage exists.

5. Exploration possibilities are probably in the Cretaceous.

6. The area has a low oil and gas resource potential.

e. Description of the Environment:

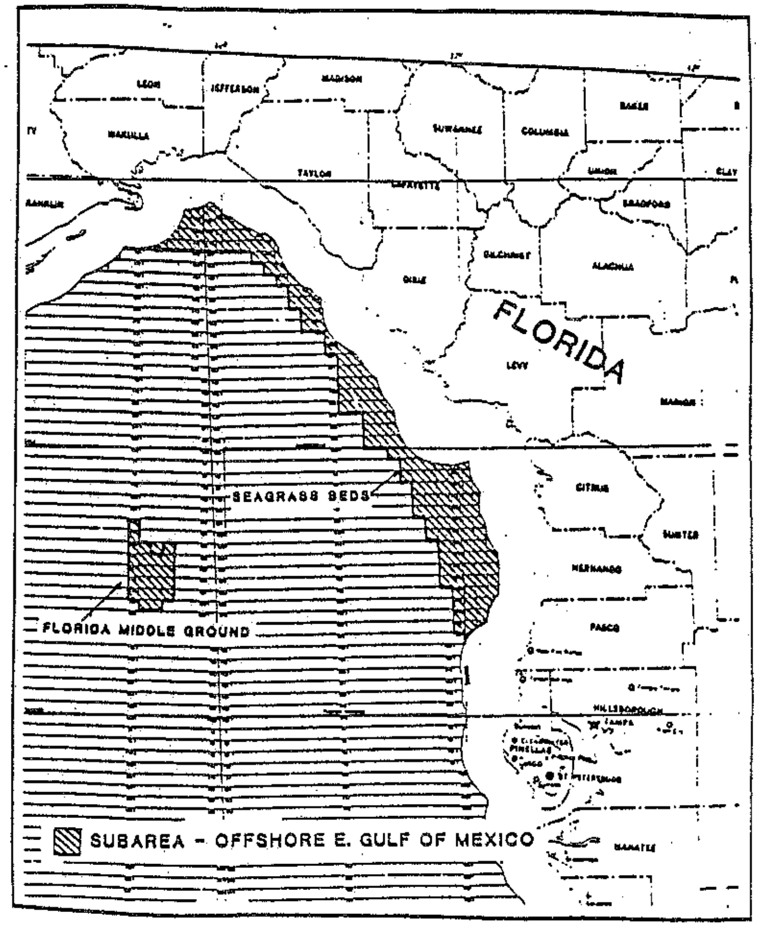
Extensive seagrass inhabit the Florida Big Bend offshore area. The actual extent of the seagrass beds is unknown at present; however, an MMS funded study is nearing completion which would help define the extent of these seagrass beds. These seagrass beds are important to the overall ecology of the Eastern Gulf of Mexico, and support numerous commercially and recreationally important fishery and wildlife species.

The coastal area surrounding the subarea is densely vegetated with salt marsh. This coastal area is important to the fish and wildlife species of the area.

f. Potential Impacts Avoided by Deferral of this Subarea:

Deferral of this subarea would preclude impacts to the seagrass areas from oil and gas drilling operations. Discharge of drill muds and cuttings directly on the seagrasses, causing smothering and potential long-term denuding of the area surrounding the drilling activity would be avoided. Direct physical impact of rig emplacement and anchoring of supply boats would also be avoided. Deferral of the subarea would also preclude oil spills from originating in the area, thereby providing a buffer between oil spill source and sensitive coastal marshes of the Florida Big Bend. Thus, deferring this small percentage of the Eastern Gulf offering would result in a very large reduction of the potential impact to these high value biological resources. Only oil spills from outside the seagrass area would still pose a threat to this area. Deferral of this subarea would remove nearly all the risk to offshore seagrass beds from oil and gas activities, since the oil spill model indicates that there is a very small probability that an oil spill occuring outside the area would enter and impact this area.





Planning Area

Eastern Planning Area - Gulf of Mexico

Subarea Name

Areas with Coral Reefs

a. Deferral Recommended by:

South Florida Regional Planning Council

b. Geographic Description:

This Eastern Gulf deletion candidate combines the 50-mile buffer zone and the Florida Middle Ground for a total of 23.1 million acres. The area ranges from 9-86 miles offshore in water depths up to 600 meters and extends from Escambia to Monroe Counties.

c. Sales (and date held) for which the Subarea was studied and Disposition in Each Sale.

The areas with coral reefs south of latitude 25ºN have never been offered for lease since this area has never been included in the Eastern Planning Area.

d. Oil and Gas Resource Potential:

See discussion for the subarea involving the Florida Middle Ground and the 50-mile buffer zone.

e. Description of the Environment:

See discussion for the subarea involving the Florida Middle Ground and the 50-mile buffer zone.

f. Potential Impacts Avoided by Deferral of this Subarea:

See subarea for the Fifty Mile Buffer Zone and Florida Middle Ground subareas.



Planning Area

Western Planning Area - Gulf of Mexico

Subarea Name

Flower Garden

a. Deferral Recommended by:

Minerals Management Service

b. Geographic Description:

Two blocks (A-392 and A-375, High Island Area, East Addition, South Extension) make up this subarea deferral. The East and West Florida Garden Banks consist of two blocks covering unique coral reef communities in area of approximately 11,250 acres.

c. Sales (and date held) for which the Subarea was studied and Disposition in Each Sale.

The two blocks in the east and west Flower Garden Banks have been deferred in Sales 74, 84, 102 and 104.

d. Oil and Gas Resource Potential:

1. Industry has shown moderate to low interest in this subarea.
2. No drilling has occurred within A-398 and A-375, HI. There has been geological and geophysical surveys in this area.
3. Location of structures, prospects, and stratigraphic traps; structures, prospects with numerous traps have been identified within the Flower Garden Reef area.
4. There is extensive seismic coverage and producing wells have been drilled in other blocks adjacent to the Flower Garden Banks.
5. Possible exploration/discovery trends within or adjacent to the subarea; this area lies wholly within the Plaislocene producive trend.
6. This area is considered to have a high gas resource potential.

Note: Boundary for a proposed marine sanctuary in the Flower Garden Banks area has not been determined. Future consideration of a deferral area conteuminous with a marine sanctuary will require a published area boundary.

e. Description of the Environment:

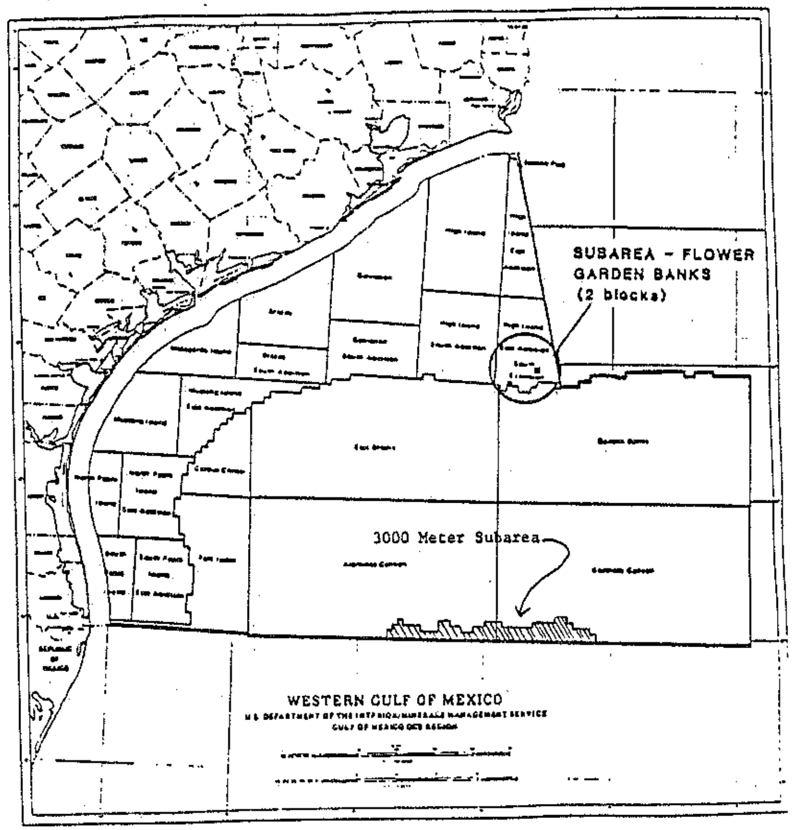
The blocks High Island A-398 and A-375, which make up the deferral area, are located at the East and West Flower Garden Banks. The Flower Garden Banks located 110 mi south of Galveston, are a unique biological and ecological resource on the OCS. The banks are surface expressions of salt domes, arising from water depths of 100 m and cresting at about 17 m. Because of their location and depth, the banks are inhabited by coral reefs. These reefs are the northernmost extension of typical Caribbean coral. The deferral area contains the area of this diversity reef located at the West Flower Garden Bank. The high diversity reef at the East Flower Garden Bank is located largely outside of the deferral area. At greater depths the high diversity reef grades into different biotic zones. The deferral area contains substantial areas of productive habitat associated with this zonation.

f. Potential Impacts Avoided by Deferral of this Subarea:

Deferral of this subarea would preclude, direct mechanical impacts from oil and gas leasing for these portions of the East and West Flower Garden Banks; including the most sensitive portion of the West Flower Garden. Drilling and platform emplacement would not be allowed within these two blocks; therefore, direct impacts from these activities to the coral biota of those portions of the Banks within the deferral area would be avoided. Such impacts include the destruction of coral habitat by the crushing breaking, and smothering of the coral. Additionally, impacts resulting form the discharge of drill cuttings and fluids or accidental subsurface spills or blowouts directly over these portions of the Banks within the deferral area would be avoided.

Deferral would not preclude damage to the area from the anchoring of oil and gas lease related vessels and rigs servicing adjacent blocks. Anchor damage has been identified as the most serious threat to the Flower Gardens. Impacts could also occur to the deferral area from the discharge of drill cuttings and fluids or accidental subsurface spills or blowouts on adjacent blocks. These impacts would be avoided regardless of the deferral should the biological stipulation be adopted.





Planning Area

All Planning Areas Gulf of Mexico

Subarea Name

Water /Depth Greater than 3,000 Meters

a. Deferral Recommended by:

Chevron

b. Geographic Description:

1. EGOM - From approximately 84°17' and 24°08' proceeding north-northwesterly along the Florida Escarpment to approximately 86°33' and 27°59' thence southwesterly to approximately 87°54' and 26°03'. Comprising 2,469 blocks and 14,074,182.94 acres.

2. CGOM - From approximately 87°54' and 26°03' proceeding west northwesterly to approximately 89°55' and 26°25' thence west southwesterly to approximately 91°17' to 25°58' comprising 400 blocks and 2,254,392.87 acres.

3. WGOM - From approximately 93°04' and 25°58' proceeding west northwesterly to approximately 93°22' and 26°09' thence westerly to 94°49' to 25°58' comprising 80 blocks and 460,800.00 acres.

c. Sales (and date held) for which the Subarea was studied and Disposition in Each Sale.

The 3,000 meter line has never been deferred in any sales.

d. Oil and Gas Resource Potential:

1. Very low interest has been shown by industry in this subarea gulfwide.

2. No exploratory drilling activity has been conducted in this area and no survey activity has been recently noted.

3. Large regional structures have been mapped for reconnaissance seismic data in the area lying between longitude 93°W and 95°W.

4. There are only a few regional seismic lines available.

5. Although little information is available, the area between longitude 93°W and longitude 95°W just south of the Sigsbee escarpment. It is possible that both Tertiary and Cretaceous sediments occur there as possible targets. Sediments in the area between longitude 85°W and longitude 91°W range from Jurassic to to Pleisocene in age. The northern part of the area north of latitude 26°W lies within a part of the Mississippi Fan, which is known to contain sand sequences that could be potential reservoir beds.

6. The area has a low resource potential for oil and gas.

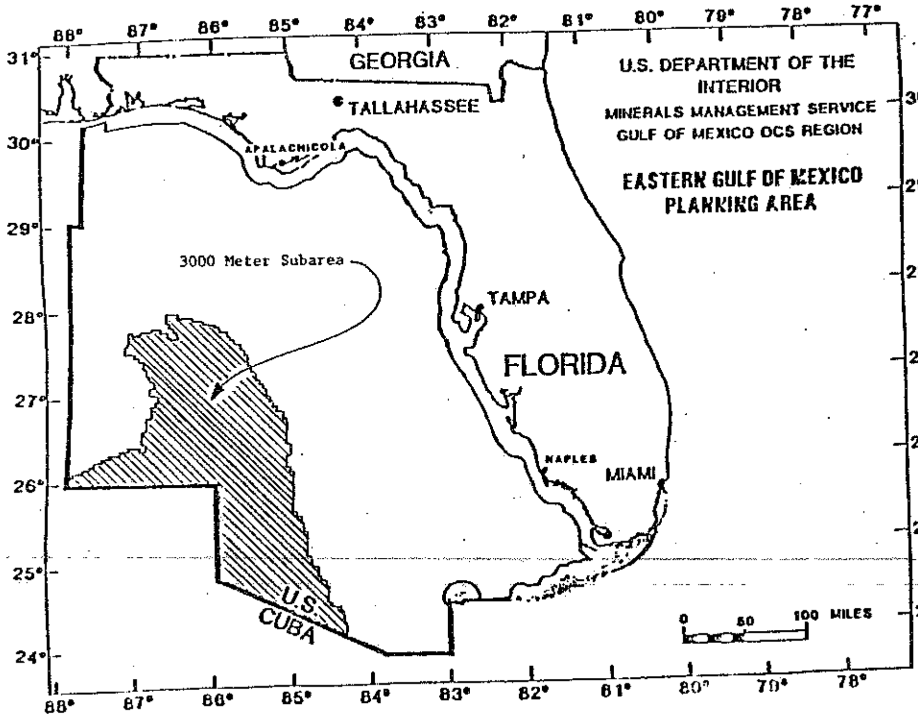


e. Description of the Environment:

The biology of the deep water environment is not well known. The deep water Gulf benthic communities exhibit depth-related zonation. At about 3,200 meters the zonation boundaries become indistinct, if present at all, probably because gradients of the physical parameters level off from this depth on as compared to the slope. The megafauna associated with these water depths is depauperate; however, the zone contains benthic species which do not occur elsewhere. Recently, deepwater vent associated communities have been discovered in the Gulf. The extend of these communities is not known. Their occurrence below 3,000 meters is possible.

f. Potential Impacts Avoided by Deferral of this Subarea:

Adoption of this deferral option would serve to prevent adverse physical effects on deepwater biological communities. No drilling or production-related oil spills would occur on those blocks. The probability of an oil spill occurring is already very low, so the adoption of this deferral would not significantly affect overall oil spill probabilities. Because the more sensitive resources are located in water depths shallower than 3,000 meters, this deferral would not reduce the anticipated overall level of affect on the area's resources.


U.S. DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE
GULF OF MEXICO OCS REGION
EASTERN GULF OF MEXICO PLANNING AREA
GEORGIA
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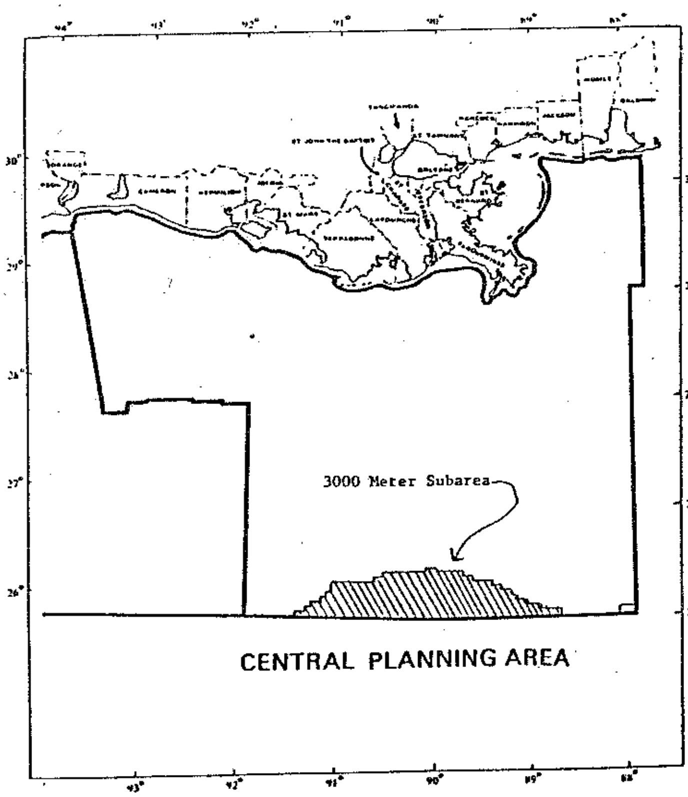
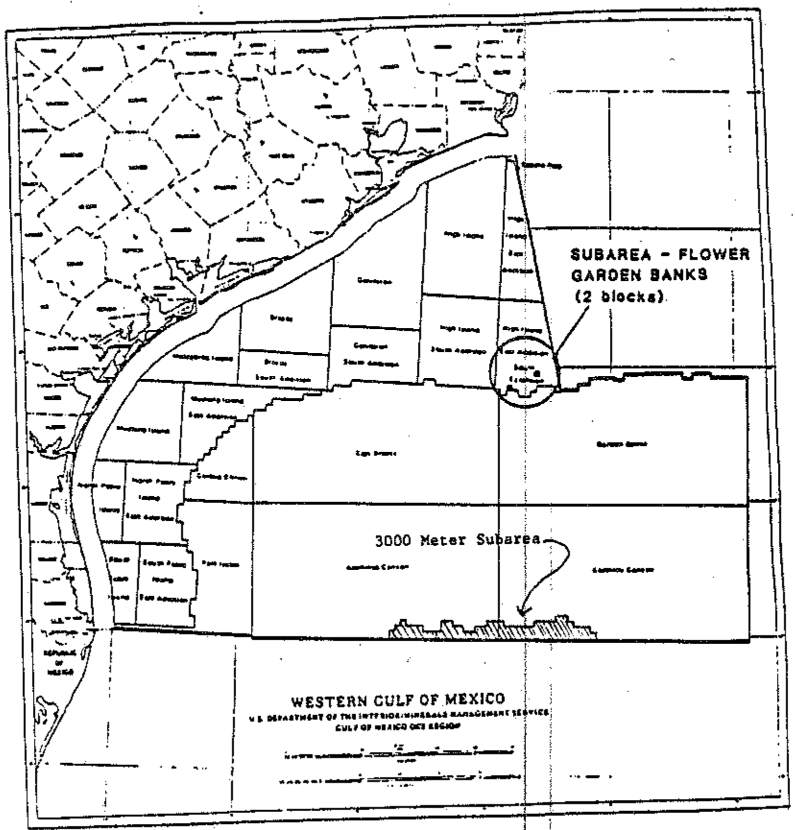

3000 Meter Subarea
CENTRAL PLANNING AREA






A. Planning Area:

Central California.

B. Subarea Name:

Point Reyes Wilderness Area.

C. Deferral Recommended By:

Leasing prohibited by OCS Lands Act.

D. Geographic Description:

The Point Reyes Wilderness Area is an onshore area which extends from the mouth of Tomales Bay to the Point Reyes Bird Observatory. The Outer Continental Shelf Lands Act Amendments of 1978 prohibits any OCS oil and gas exploration or development within 15 miles of the boundaries of the wilderness area unless the State of California allows oil and gas activities in State waters. Thus, this subarea deferral includes approximately 92 blocks (500,000 acres) located within 15 miles of the wilderness area. A portion of the Point Reyes/Farallon Islands National Marine Sanctuary subarea is included in this deferral.

E. Sales and Date Held for Which the Subarea was Studied and Disposition In Each Sale:

This subarea was studied for Sale P1 held on May 14, 1963. Approximately 20 blocks were leased as a result of this Sale. There are no active leases in the area currently.

F. Oil and Gas Resource Potential:

1. This area was nominated in 1978 for Sale 53.

2. Six exploratory wells were drilled in this subarea, however, there were no significant shows. The most recent geological and geophysical permit was issued on October 3, 1980.

3. No structural traps have been identified. Stratigraphic traps may be present throughout the area.

4. In terms of the quantity and quality, the geotechnical data available in the proposed deletion area are sufficient to define specific traps throughout the entire area.

5. Possible exploration/discovery trends within or adjacent to the subarea, including the San Andreas Fault Zone and the Drakes Bay-Bolinas Trend, extend northwestward across the northeast part of the area. The Farallon-Pigeon Point High Trends extend northwestward along the southern border of the area.

Point Reyes Wilderness Area continued.

G. Description of the Environment:

The shoreline of the wilderness area contains unaltered rocky shores and sandy beaches which maintain rich intertidal communities, serve as breeding and haulout areas for marine mammals, and as a nesting area for seabirds.

H. Potential Impacts Avoided by Deletion of this Subarea:

Impacts to intertidal communities on the Point Reyes Wilderness Area would be reduced due to the elimination of potential platforms and associated development activities. Similarly, the risk of potential platform spills originating from within this area would be eliminated. This would provide additional protection for the intertidal communities, marine mammal haulout areas and seabird nesting areas.



A. Planning Area:

Central California.

B. Subarea Name:

Cordell Bank.

C. Deferral Recommended By:

Department of the Interior.

D. Geographic Description:

Cordell Bank is a large seamount lying 50 miles northwest of San Francisco and approximately 30 miles north of the Farallon Islands. The center of the bank is near 38° 01' north latitude, 123° 25' west longitude. This subarea includes parts of 4 blocks, approximately 22,700 acres using the 91 meter contour.

E. Sales and Date Held for which this Subarea was Studied and Description in Each Sale:

None.

F. Oil and Gas Resource Potential:

1. No nominations have been received for this subarea.

2. No wells have been drilled in this subarea. The most recent geological and geophysical permit was issued on October 3, 1980.

3. No structural traps have been identified in the mapped area. Stratigraphic traps may be present around the border of the area.

4. In terms of quantity and quality, the geotechnical data available in the proposed deletion area are sufficient to define specific traps throughout the entire area.

5. Possible exploration/discovery trends within or adjacent to the subarea include the Farallon-Pigeon Point High which extends southeastward from Cordell Bank.

G. Description of the Environment:

Cordell Bank is roughly elliptical and is 9.5 by 4.5 miles at the 91 meter depth contour. Overall the area is relatively flat at depths of 180 to 210 ft. (55 to 63 meters), but is interrupted by steep pinnacles. There are at least four ridges within diving depths of 120 to 140 ft. (37 to 43 meters) although the shallowest depth is 114 ft. (35 meters). The biological community on Cordell Bank is described by Schneider as "exceptionally lush and healthy, consisting of

Cordell Bank continued.

algae, invertebrates, fish, birds and mammals." Schneider states: "The list of species which have been collected at Cordell Bank include many of the common organisms such as the strawberry anemone Corynactis californica, and some uncommon or rare species such as the hydrocoral Allopora californica, the diatom Entopyla cf. E. incurvata, the gastropod Pedicularia californica, and several new taxa, including at least two new genera of algae and a possible new species of the scallop Chylamys. It is very likely that many undescribed organisms exist at Cordell Bank and will be found in future studies."

H. Potential Impacts Avoided by Deletion of this Subarea:

Deferral of this subarea will reduce impacts to water quality in the area since no platform will occur. The water quality of the area is unaltered and pristine with respect to anthropogenic influences. The principal impacts that would be avoided by this deferral would be to eliminate the possibility of adverse effects to the productive hard bottom benthic community and the hydrocoral Allopora californica.



A. Planning Area:

Central California.

B. Subarea Name:

Point Reyes/Farallon Islands National Marine Sanctuary.

C. Deferral Recommended By:

Department of the Interior.

D. Geographic Description:

The boundaries of the marine sanctuary are officially defined as follows:

"The sanctuary consists of an area of the waters adjacent to the coast of California north and south of the Point Reyes Headlands, between Bodega Head and Rocky Point and the Farallon Islands (including Noonday Rocky), and includes approximately 948 square nautical miles.

"The shoreward boundary follows the mean high tide line and the seaward limit of Point Reyes National Seashore. Between Bodega Head and Point Reyes Headlands, the sanctuary extends seaward 3 nm beyond State waters. The sanctuary also includes the waters within 12 nm of the Farallon Islands, and between the Islands and the mainland from Point Reyes Headlands to Rocky Point. The sanctuary includes Bodega Bay, but not Bodega Harbor."

Portions of the San Francisco Bay and Point Reyes Wilderness Area deferrals are included within this subarea.

E. Sales and Date Held for which this Subarea was Studied and Description in Each Sale:

Nine blocks were leased off Pt. Reyes on which two wells were drilled in the May 14, 1963 Sale. No discoveries were announced and the leases were relinquished.

F. Oil and Gas Resource Potential:

1. Part of the subarea was nominated for Sale 73.

2. Two wells were drilled in this subarea as a result of the 1963 Sale; however, no discoveries were announced. The most recent geological and geophysical permit was issued on October 3, 1980.

3. Stratigraphic traps may be present in the northeastern one-half and the southwestern one-fourth of the area. No structural traps have been identified in the area.

Point Reyes/Farallon Islands National Marine Sanctuary continued.

4. In terms of quantity and quality, the geotechnical data available in the proposed deletion area are sufficient to define specific traps throughout the area except the southwestern one-fourth, where data are not sufficient to define zones of hydrocarbon potential.

5. Possible exploration/discovery trends within or adjacent to the subarea include the San Andreas fault zone and the Drakes Bay-Bolinas trend which extends northwestward across the northeast part of the area and the Farallon-Pigeon Point high which trends northwestward across the central part of the area.

G. <u>Description of the Environment:</u>

The shorelines consist of rocky shores and sandy beaches which maintain rich intertidal communities. The sanctuary contains the largest breeding colony of seabirds in California and is an important pinniped rookery. The waters of the area are highly productive and are an important foraging area for the birds and pinnipeds.

H. <u>Potential Impacts Avoided by Deletion of this Subarea:</u>

Deferral of this subarea would reduce a variety of potential environmental effects. First, the potential of an oil spill affecting the islands would be reduced, thereby protecting the habitats of seabirds, pinnipeds, and other marine dependent life. Even if an oil spill from another area drifted into the area there would be more time for weathering and the spill would be less toxic. Second, the lack of exploration and development activity would eliminate the possibility of adverse effects of normal oil and gas operations on biological communities, as well as social and cultural environments.



A. <u>Planning Area:</u>

Central California.

B. <u>Subarea Name:</u>

San Francisco Bay Precautionary Area.

C. <u>Deferral Recommended By:</u>

Department of the Interior.

D. <u>Geographic Description:</u>

This area represents a portion of the San Francisco Bay Vessel Traffic Precautionary Area and an adjacent area totaling 16 whole and partial blocks. The area is just south of the entrance to San Francisco Bay offshore the San Francisco/San Mateo County line, and bounded to the north and west by the Farallon Islands-Pt. Reyes National Marine Sanctuary and to the east by the 3-mile State jurisdiction line. It has been the policy of the U.S. Coast Guard to not allow structures in established precautionary areas.

E. <u>Sales and Date Held for which this Subarea was Studied and Description In Each Sale:</u>

This subarea was studied for Sale 53, but deferred prior to the May 28, 1981 Sale.

F. <u>Oil and Gas Resource Potential:</u>

1. Part of the subarea was nominated for Sale 73 and other parts were nominated for Sale 53.

2. No wells have been drilled in this subarea. The most recent geological and geophysical permit was issued on August 22, 1984.

3. Stratigraphic traps may be present throughout the area. Structural traps have been identified throughout the mapped area.

4. In terms of quantity and quality, the geotechnical data available in the proposed deferral area are sufficient to define specific traps in all parts of the area except the northeast ±15% of the area in which data is sufficient to define specific plans only.

5. Possible exploration/discovery trends within or adjacent to the subarea include the San Andreas Fault Zone which extends across the northeastern edge of the area. The Drakes Bay-Bolinas trend extends across the area. Oil sands are exposed onshore east of the area.

San Francisco Bay Precautionary Area continued.

G. Description of the Environment:

The San Francisco Bay Precautionary Area is part of the marine vessel routing system controlled by the U.S. Coast Guard and the International Maritime Organization. This area is directly adjacent to the entrance to San Francisco Bay, one of the busiest ports in the nation, and includes access to the Ports of San Francisco, Oakland, Richmond and Sacramento. For calendar year 1982 the San Francisco Harbor had a total of 9,640 inbound vessel trips.

The resources along the nearby coast include San Francisco Zoo, Lake Merced/Harding Park, Fort Funston, Burton Beach, Thornton State Beach and Palisades Park. This region is of high aesthetic and recreational value due to the presence of numerous beaches and coastal parks. The area also affords many panoramic ocean views from the beaches and steep bluffs.

H. Potential Impacts Avoided by Deletion of this Subarea:

Deferral of this subarea would reduce or eliminate potential adverse effects on vessel traffic, recreation and tourism, and aesthetics. In addition, protection of biological, social and cultural environments would be enhanced.



A. Planning Area:

Central California.

B. Subarea Name:

Monterey Bay.

C. Deferral Recommended By:

Department of the Interior.

D. Geographic Description:

The proposed Monterey Bay subarea deferral includes the area enclosed by a southwest line that extends from a point 6 miles north of Santa Cruz to a point which is 48 miles offshore due west of Malpaso Creek. This deferral includes 104 blocks and approximately 516,315 acres. Deferring the area offshore Monterey Bay along with the Big Sur subarea would reduce the size of the Central California Planning Area by approximately one-third.

E. Sales and date held for which the subarea was studied and disposition in each sale:

None.

F. Oil and Gas Resource Potential:

1. Parts of this subarea were nominated in 1981 for Sale 73.

2. No wells have been drilled in this subarea. The most recent geological and geophysical permit was issued on November 26, 1982.

3. Structural traps have been identified throughout the mapped areas northeast of a line from N826/E120, to N852/E105. Stratigraphic traps may be present throughout the entire area.

4. In terms of quantity and quality, the geotechnical data available in the proposed deletion area are sufficient to define specific traps in most areas northeast of a line from N826, E120, to N852, E105. To the west of this area data are sufficient to define variations in the thickness of the sedimentary section on the upper portion of the continental slope and to define the general distribution limits of deep sea fan deposits. Available data are inadequate for the identification of specific traps west of a line from N826/E120 to N852/E105.

5. Possible exploration/discovery trends within or adjacent to the subarea include the northwest trending Sur-Nacimiento and Palo Colorado-San Gregorio fault zones and associated anticlines.

Monterey Bay continued.

G. Description of the Environment:

The important biological areas contained in this deletion area include the subtidal Monterey Canyon in Monterey Bay with its included hydrocoral *Allopora californica*. Areas that are thought to be possibly unique include Pacific Grove Marine Gardens Area of Special Biological Significance, Cypress Point and Point Pinos, and the area from Carmel River to Point Lobos. The important estuary adjacent to the deletion area is Elkhorn Slough. The greatest public concern in this area has been expressed for the sea otter whose range occurs within this deletion area.

H. Potential Impacts Avoided by Deletion of this Subarea:

Deferral of this subarea would reduce the potential visual impacts and provide protection for a significant number of Monterey Bay resources by ensuring additional time for weathering, diversion and cleanup of an exploration or development related oil spill in the event such a spill should occur. Specific resources provided protection are mentioned above and include: 1) Intertidal Benthos--rocky intertidal areas of Pacific Grove, Cyprus Point, Point Pinos, Carmel River to the Point Lobos area; 2) Subtidal Benthos, including the Monterey Canyon, 3) the important estuary, Elkhorn Slough, and 4) the California sea otter habitat.



A. Planning Area:

Central California.

B. Subarea Name:

Big Sur Area.

C. Deferral Recommended By:

Department of the Interior.

D. Geographic Description:

The Big Sur subarea includes that area extending due west to a point 48 miles offshore Malpaso Creek. The western boundary of the deferral area extends southwest to a point 131 miles offshore the Monterey-San Luis Obispo County border. This proposed deferral includes approximately 460 blocks and approximately 2.5 million acres. Deferral of the Big Sur subarea along with the area offshore Monterey Bay would reduce the size of the Central California Planning Area by approximately one-third.

E. Sales and Date held for which the Subarea was Studied and Disposition in Each Sale:

None.

F. Oil and Gas Resource Potential:

1. Parts of this subarea were nominated in 1981 for Sale 73.

2. No wells have been drilled in this subarea. The most recent geological and geophysical was issued on October 28, 1986.

3. Structural traps have been identified throughout the mapped areas northeast of a line from N826/E120, to N852/E105. Stratigraphic traps may be present throughout the area east of the base of the continental slope.

4. In terms of quantity and quality, the geotechnical data available in the proposed deletion area are sufficient to define specific traps in most areas northeast of a line from N826/E120 to N852/E105. To the west of this area data are sufficient to define variations in the thickness of the sedimentary section on the upper portion of the continental slope and the general distribution limits of deep sea fan deposits. Available data are inadequate for the identification of specific traps west of a line from N825/E120 to N852/E105.

5. Possible exploration/discovery trends within or adjacent to the subarea include the northwest trending Hosgri and Sur-Nacimiento fault zones and associated anticlines.

Big Sur Area continued.

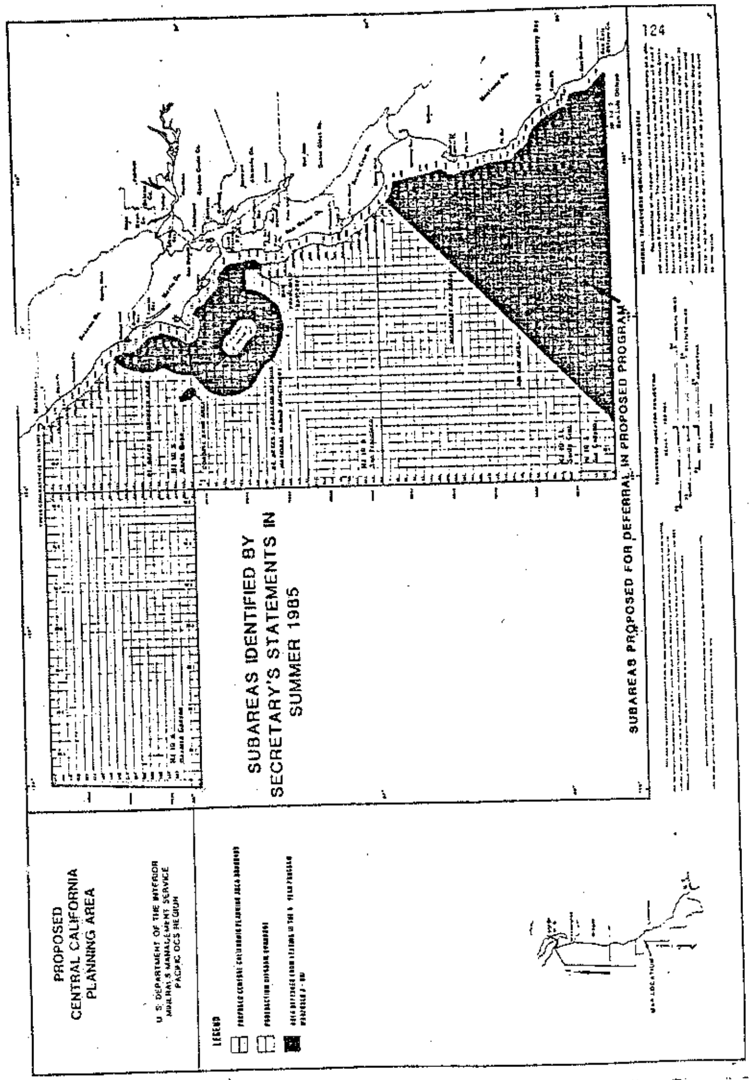
G. Description of the Environment:

The subarea includes the California sea otter population and range from the Monterey-San Luis Obispo county line north to Malpaso Creek. In addition to the sea otter, thousands of seabirds, including the brown pelican, and gray whales use this section of the coast seasonally. Over one million visitors a year visit this subarea and adjacent coastline, attracted to the many scenic areas and cultural attractions such as Hearst Castle and various State parks and reserves.

H. Potential Impacts Avoided by Deletion of this Subarea:

Deferral of this area would reduce the potential visual effects and provide protection for a significant number of resources by ensuring additional time for weathering, diversion, and cleanup of an exploration or development related oil spill should such a spill occur. Potential effects of normal operations on air or water quality as well as social, biological and cultural environments would also be reduced or eliminated.





A. Planning Area:

Southern California.

B. Subarea Name:

Santa Barbara Channel Ecological Preserve and Buffer Zone.

C. Deferral Recommended By:

Department of the Interior.

D. Geographic Description:

The Santa Barbara Channel Ecological Preserve and Buffer Zone is located south of the city of Santa Barbara. The preserve was established March 21, 1969 by Public Land Order 4587. The Preserve consists of ten full and partial tracts "withdrawn from all forms of disposition, including mineral leasing, and reserved for use for scientific, recreational and other similar uses." Eight additional tracts (full and partial) adjacent to the Preserve were designated as an "adjunct to the Ecological Preserve." These tracts have become known as the Buffer Zone and were removed from consideration for leasing by the Order. In all, a total of approximately 55,000 acres are affected.

E. Sales and Date Held for Which the Subarea was Studied and Disposition In Each Sale:

The subarea was extensively nominated for Sale P4, held February 6, 1968, prior to its designation as a preserve, but all tracts were deleted prior to the Sale, to protect the State Sanctuary. The area was again nominated in 1980, for Sale 68, but all tracts were deferred before preparation of the environmental impact statement.

F. Oil and Gas Resource Potential:

1. The subarea was extensively nominated in response to the Sale 68 Call for Information and Nominations in 1980.

2. No wells have been drilled in this subarea. The most recent geological a and geophysical permit was issued on December 3, 1985.

3. Structural traps have been identified in the extreme eastern, western and southern parts of the mapped areas. Stratigraphic traps may be present to the southwest part of the area.

4. In terms of quantity and quality, the geotechnical data available in the proposed deferred area are sufficient to define specific traps throughout the entire area.





5. Possible exploration/discovery trends within or adjacent to the subarea include the Rincon anticlinal discovery trend and the Pitas Point anticlinal discovery trend both of which extend into the area.

G. Description of the Environment:

The deferral area includes what in the late fifties and early sixties, was habitat for a large population of benthic tongue worms *Listriolobus pelodes*. More recent surveys in the general area have suggested that the population may not have maintained the large numbers. The nearshore environment contains: Naples Reef, a productive kelp area used for scientific study by University of California at Santa Barbara, Goleta Slough, also studied by UCSB, and Santa Barbara Harbor.

H. Potential Impacts Avoided by Deletion of this Subarea:

Water quality in the adjunct to the Santa Barbara Channel Ecological Preserve would be protected by the deferral due to elimination of drill muds and cuttings discharge and the elimination of potential oil spill occurrences in the area. Water quality for the entire proposed lease sale area would not be significantly different; however, risks to fish, commercial fisheries and sport fisheries would be slightly less. Similarly, the risk of impacts resulting from a spill striking the breeding and roosting colonies of seabirds and harbor seal pupping grounds of Santa Cruz and Santa Rosa Islands would be slightly reduced.

The deferral will reduce the probability of oil reaching the relatively unaltered estuary Goleta Slough near Santa Barbara and the inner or northern shores of Santa Cruz Island and the shallow island shelves of the Channel Islands National Marine Sanctuary. The potential impact to recreational resources, particularly around Santa Barbara, would be reduced slightly.

The adoption of the alternative would remove eight tracts from Department of Defense concern. The potential impact to visual resources would be reduced slightly with the elimination of platforms that could be seen from shore.

A. Planning Area:

Southern California.

B. Subarea Name:

Channel Islands National Marine Sanctuary.

C. Deferral Recommended By:

Department of the Interior.

D. Geographic Description:

The Channel Islands National Marine Sanctuary consists of San Miguel, Santa Rosa, Santa Cruz and Anacapa Islands on the outer region of the Santa Barbara Channel and Santa Barbara Island approximately 40 miles south of the mainland coast.

The Channel Islands National Marine Sanctuary, designated on September 22, 1980, includes only the ocean area from the mean high tide line seaward to 6 nm, a total of 175 blocks approximately 479,000 acres. Hydrocarbon exploration and development activities are prohibited by regulation within the boundaries of the Channel Islands National Marine Sanctuary.

E. Sales and Date Held for which this Subarea was Studied and Description in Each Sale:

Twenty-four tracts were leased in the February 6, 1968 sale, on which ten wells were drilled. Four of the leases are still active, two within the producing Santa Clara Unit, one producing on its own, and the other has a pending suspension of production. The producing platform is located outside the Channel Islands National Marine Sanctuary boundary.

F. Oil and Gas Resource Potential:

1. Portions of tracts abutting the Sanctuary received nominations for the Sale 80 Call in 1982.

3. Structural traps have been identified throughout the mapped area. Stratigraphic traps may be present throughout the subarea.

4. In terms of quantity and quality, the geotechnical data available in the proposed deletion subarea are sufficient to define specific traps throughout the entire area.





G. Description of the Environment:

The northern Channel Islands are important for numerous reasons. Particularly significant are the marine biological, archaeological, and paleontological resources found on the islands. For example, they contain the largest and most diverse temperate water pinniped (seals and sea lions) community in the world. More than 36,900 pinnipeds, of six different species, were counted on the islands, themselves, excluding the surrounding waters. Also, there is evidence of human inhabitants going back to 30,000 years, and fossils of the dwarf mammoth.

H. Potential Impacts Avoided by Deletion of this Subarea:

Deferral of this subarea will reduce the potential effects of an oil spill to the islands should such an event occur in that the time required for spilled oil to reach shore will increase by at least four to five hours, possibly by as much as 10 hours. During this time, a significant amount of evaporation, dissolution and weathering of the oil would occur, reducing the quantity and toxicity. Also, it would allow more time for oil spill cleanup and containment equipment to be mobilized. The oceanographic conditions off Southern California are fairly good for handling an oil spill. With this additional time, the chances of effectively protecting sensitive marine resources are increased by four to five hours. Specifically, the sensitive intertidal and near-shore subtidal resources and pinnipeds and seabirds and their resources may be less likely to be directly contacted by the oil. Even if the oil did reach these resources, there would be less of it, it would be more weathered, and it would be less toxic.

Increasing the distance between OCS development and these resources deleterious effects from drilling muds, cuttings and formation water would also reduce the vessel traffic, human intrusion and noise generated during exploration and development. Potential disruption of critical breeding and nesting activities for seabirds and pinnipeds would, therefore, be reduced. Also, the risk of damage from platforms and deleterious effects from drilling muds, cuttings and formation water would be reduced.

A. Planning Area:

Southern California.

B. Subarea Name:

San Nicolas Basin Navy Operating Area.

C. Deferral Recommended By:

Department of the Interior.

D. Geographic Description:

The San Nicolas Basin Navy Operating Area is principally located in the ocean south of Santa Barbara Island between San Nicolas Island and San Clemente Island. This deferral would remove this area from the oil and gas leasing program.

E. Sales and Date held for which the Subarea was Studied and Disposition in Each Sale:

One tract was leased in Sale 35, held December 11, 1975, but the lease has since expired. The area was studied in Environmental Impact Statements for Sale 48 (June 29, 1979), and Sale 80 (October 17, 1984), but no tracts were leased.

F. Oil and Gas Resource Potential:

1. The area received low industry interest in response to the Sale 80 Call for Information and Nominations.

2. No wells have been drilled in this subarea. The most recent geological and geophysical permit was issued on November 18, 1986.

3. Structural traps have not been identified because of a lack of seismic data. Stratigraphic traps may be present, but have not been defined with available data.

4. In terms of quantity and quality, the geotechnical data available in the proposed deletion area are sufficient to define a moderately thick to thick sedimentary section westward to at least the upper part of the continent slope, variations in the thickness of the sedimentary section on the continental shelf and slope, the base of the continental slope and the general distribution limits of deepsea fan deposits. Available data are inadequate for the identification of specific traps over the entire area.

5. Possible exploration/discovery trends within or adjacent to the subarea include north oriented anticlinal trends.



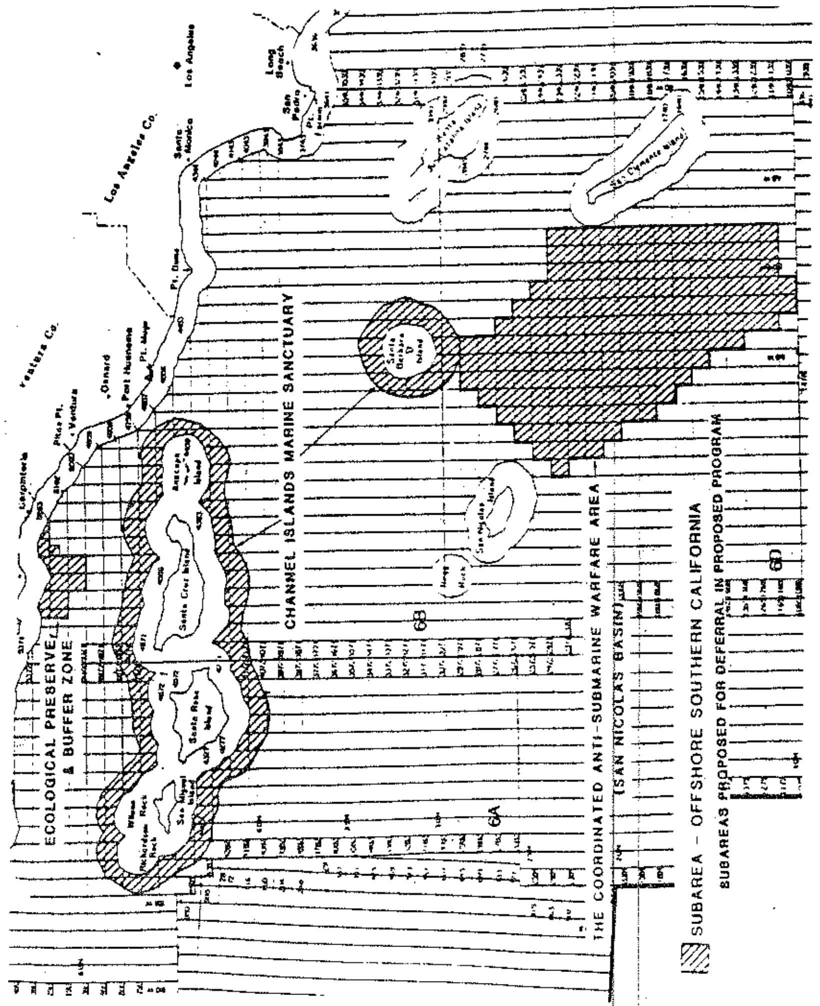
San Nicolas Basin Navy Operating Area continued.

G. Description of the Environment:

This is one of the open ocean areas used for submarine testing and training. Each military subarea is used for a different type of military training activity necessary for national defense.

H. Potential Impacts Avoided by Deletion of this Subarea:

Deferral of this subarea would reduce potential local impacts to military uses and other resources found in this area.






A. Planning Area:

Southern California.

B. Subarea Name:

Deukmejian Deferral, Southern California.

C. Deferral Recommended By:

Governor of California.

D. Geographic Description:

This deferral would affect portions of the entire southern California coastline. A total of 64 areas along the entire California coast were recommended for deferral. The Governor's deferral request included a six mile buffer around Areas of Special Biological Significance, a three mile buffer around State Oil and Gas Sanctuaries and all waters deeper than 1,000 meters. Areas of Special Biological Significance in southern California include: San Miguel Island, Santa Rosa Island, Santa Cruz Island, San Nicolas Island, Begg Rock, Santa Barbara Island, Anacapa Island, San Clemente Island, Mugu Lagoon to Latigo Point, Santa Catalina Island, La Jolla Ecological Reserve, Heisler Park Ecological Reserve, San Diego Marine Life Refuge, Newport Beach Marine Life Refuge, and the Irvine Coast Marine Life Refuge.

E. Sales and Date Held for which the Subarea was Studied and Disposition In Each Sale:

Portions of the northern part of this subarea were studied for Sale 73, held on November 30, 1983 and one block was leased. The northern part of this subarea was also studied for Sale 53, held May 28, 1981 and five blocks were leased. The nearshore areas south of Point Conception, the areas around Begg Rock, San Nicolas, Santa Catalina, and San Clemente Islands were studied for Sale 80, however, no blocks were leased in this subarea. The area offshore Laguna Beach was studied in the Sale 68 environmental impact statement in 1981, but the tracts were withdrawn prior to the June 11, 1982 sale. Two tracts offshore Long Beach and Costa Mesa were leased in Sale 35 in 1975, however, both leases have sinced expired.

F. Oil and Gas Resource Potential:

1. Parts of this subarea were nominated for Sale 73 and other parts were nominated for Sale 80.

2. One well was drilled on a Sale 35 lease in Long Beach Harbor. The most recent geological and geophysical permit was issued October 28, 1986.

Deukmejian Deferral, Southern California continued.

3. Structural traps have been identified throughout most of the area east of the base of the continental slope, with the exceptions of an area adjacent to Santa Catalina Island and areas on or near the continental slope west of San Nicolas Island and Santa Lucia Bank. Stratigraphic traps may be present throughout the entire area east of the base of the continental slope.

4. In terms of quantity and quality, the geotechnical data available in the proposed deletion area are sufficient to define specific traps within the nearshore areas and the San Nicolas and Velero basins. Available data are inadequate for the identification of specific traps for areas west of the base of the continental slope and in the areas noted above.

5. Possible exploration/discovery trends within or adjacent to the subarea from south to north include the Newport-Inglewood, Wilmington-Torrance, Palos Verdes fault, Venice Beach-El Segundo, Beverly Hills Sawtelle, Hueneme-Sockeye, Santa Clara-Santa Rosa, Montalvo, Pitas Point, Rincon-Dos Cuadras, South Elwood, and Hosgri fault trends.

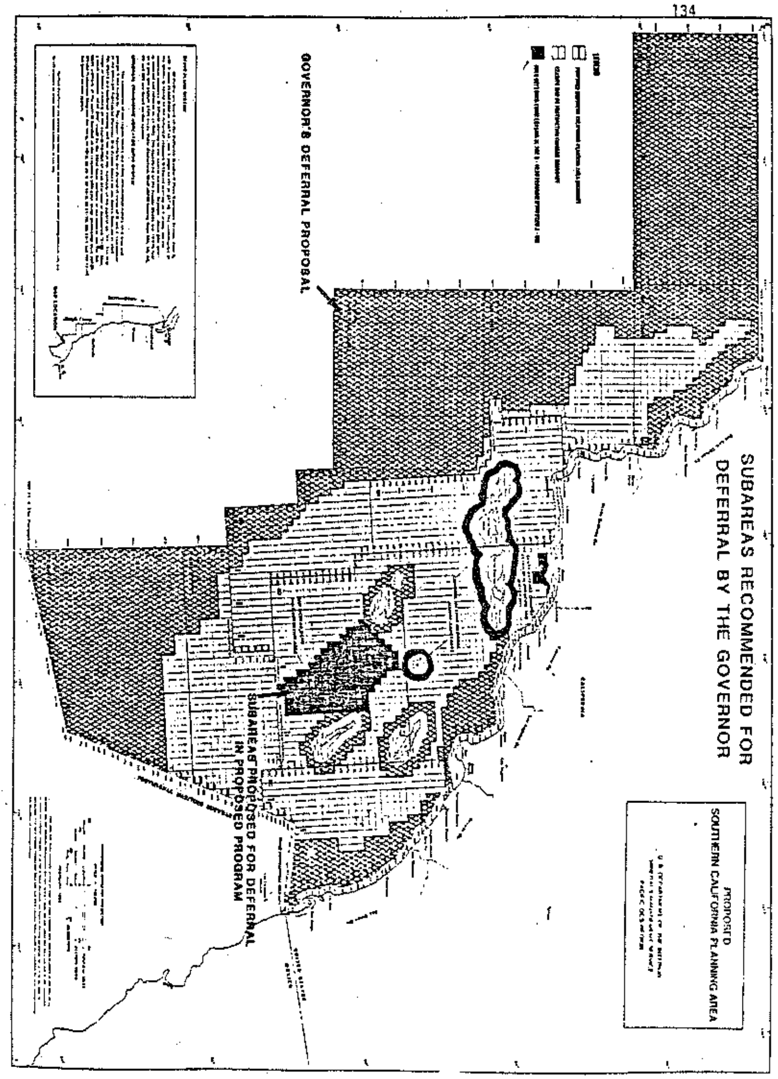
G. <u>Description of the Environment:</u>

The southern California planning area is described in the draft environmental impact statement of the "Proposed 5-Year Outer Continental Shelf Oil and Gas Leasing Program; January 1987-December 1991" pages III C-53 to C-73. A description of the environment may also be found on pages 97 through 184 of Attachment V to the "Proposed Program" (Decision and Summary) and in the environmental impact statement for Sale 80 which was done in April of 1984.

H. <u>Potential Impacts Avoided by Deletion of this Subarea:</u>

The areas requested for deferral would provide zones free of oil and gas development which would provide some protection to the physical, biological, and socioeconomic resources located in them. Further, the deferral of these areas would reduce localized impacts resulting from the construction and operation of the platforms. Environmental





A. Planning Area:

Central California.

B. Subarea Name:

Deukmejian Deferral, Central California.

C. Deferral Recommended By:

Governor of California.

D. Geographic Description:

This deferral would affect portions of the entire central California coastline. A total of 64 areas along the entire California coast were recommended for deferral. The Governor's deferral request included a six mile buffer around Areas of Special Biological Significance, a three mile buffer around State Oil and Gas Sanctuaries and all waters deeper than 1,000 meters. Areas of Special Biological Significance in central California include: Del Mar Landing Ecological Reserve, Gerstle Cove Reserve, Bodega Marine Life Refuge, Farallon Islands, Point Reyes Headland Reserve, Point Reyes National Wilderness Area, Bird Rock, Double Point, Duxbury Reef Reserve, James V. Fitzgerald Marine Reserve, Ano Nuevo Point and Island, Pacific Grove Marine Gardens Fish Refuge and Hopkins Marine Life Refuge, Carmel Bay, Point Lobos Ecological Reserve, Julia Pfeiffer Burns Underwater Park, Ocean area surrounding the mouth of Salmon Creek, Pygmy Forest Ecological Staircase, and Saunders Reef Kelp Beds.

E. Sales and Date Held for which the Subarea was Studied and Disposition in Each Sale.

Lease Sale P1, Northern and Central California, was held on May 14, 1963 and 1 tract was leased off Point Ano Nuevo. This lease was relinquished in 1968. This area was studied for possible inclusion in Lease Sale 53 held on May 28, 1981, however, no tracts were offered in the Central California Planning Area.

F. Oil and Gas Resource Potential:

1. Tracts off the Sonoma County Coast received nominations for Sale 73, however, no blocks were offered.

2. One well was drilled on the lease offshore Point Ano Nuevo, but there were no significant shows. The most recent geological and geophysical permit was issued on October 28, 1986.

3. Structural traps have been identified throughout the mapped areas east of the base of the continental slope. Stratigraphic traps may be present throughout the area east of the base of the continental slope.



Deukmejian Deferral, Central California continued.

4. In terms of quantity and quality, the geotechnical data available in the proposed deletion area are sufficient to define specific traps within the nearshore areas. Available data are inadequate for the identification of specific traps in most areas southwest of a line from N826/E120 to N895/E80.

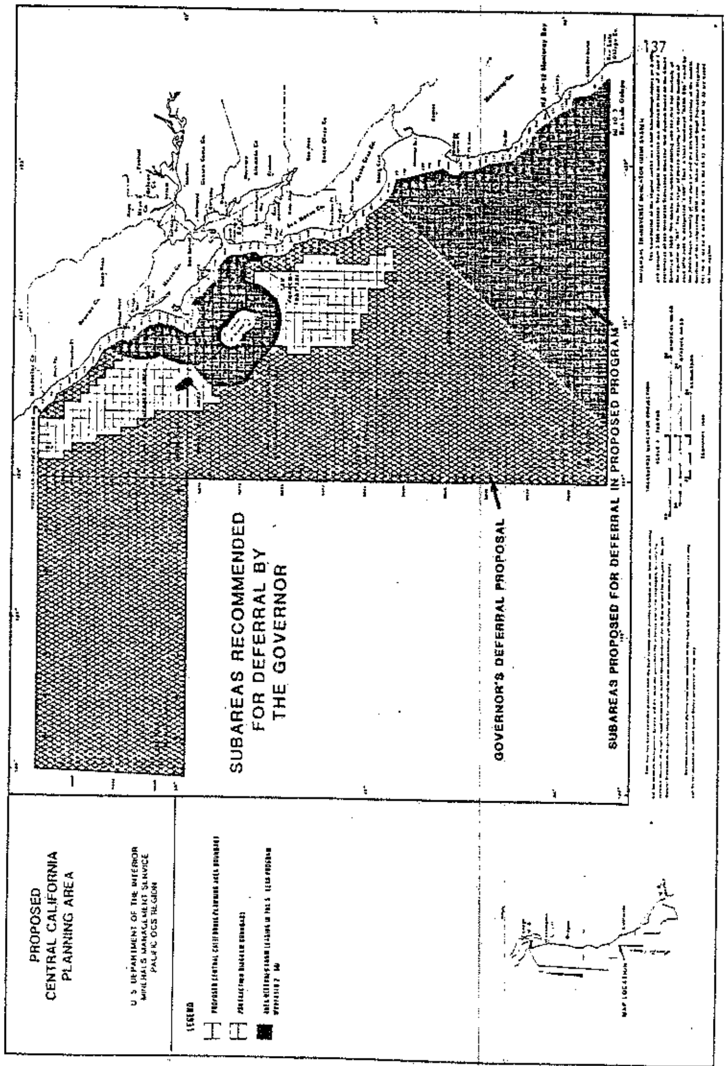
5. Possible exploration/discovery trends within or adjacent to the subarea include the Hosgri-Sur-Nacimiento-Palo Colorado-San Gregorio fault zones and associated anticlines which extend northwest-southeast throughout the area, northwest-oriented anticlinal trends in Ano Nuevo, La Honda and Bodega basins which have been partially explored by industry, the San Andreas fault zone and associated anticlines which trend northwestward along the northeastern edge of the area, and the Drakes Bay-Bolinas trend in the La Honda basin.

G. Description of the Environment:

The central California planning area is described in the draft environmental impact statement of the "Proposed 5-Year Outer Continental Shelf Oil and Gas Leasing Program; January 1987-December 1991" on pages III C-39 to C-52. Additional environmental information for central California may be found on pages 70 through 79 of Attachment V to the "Proposed Program" (Decision and Summary) and in the final environmental impact statement for Sale 73 done in June of 1983.

H. Potential Impacts Avoided by Deletion of this Subarea:

The areas requested for deferral would provide zones free of oil and gas development which would provide some protection to the physical, biological, and socioeconomic resources located in them. Further, the deferral of these areas would reduce localized impacts resulting from the construction and operation of the platforms. Environmental resources at risk would include water quality, air quality, biological habitats, cultural resources, commercial fisheries and visual resources. In the unlikely event of an oil spill, the deferral areas would provide additional buffering for the resources at risk by providing time for the drifting oil to be dissipated or neutralized through weathering, containment, natural dispersion, and/or chemical dispersion.






A. Planning Area:

Northern California.

B. Subarea Name:

Deukmejian Deferral, Northern California.

C. Deferral Recommended By:

Governor of California.

D. Geographic Description:

This deferral would affect portions of the entire northern California coastline. A total of 64 areas along the entire California coast were recommended for deferral. The Governor's deferral request included a six mile buffer around Areas of Special Biological Significance, a three mile buffer around State Oil and Gas Sanctuaries and all waters deeper than 1,000 meters. Areas of Special Biological Significance in northern California include: Trinidad Head Kelp Beds, Kings Range National Conservation Area, and the Redwoods National Park.

E. Sales and Date held for which the Subarea was Studied and Disposition in Each Sale:

Lease Sale P1, Northern and Central California, was held on May 14, 1963 but no tracts within this subarea were leased. There are no active leases from Lease Sale P1. This area was studied for possible inclusion in Lease Sale 53 held on May 28, 1981, however, no blocks were offered in the Northern California Planning Area.

F. Oil and Gas Resource Potential:

1. Parts of this subarea were nominated for Sale 73, and other parts have been nominated for Sale 91.

2. No wells have been drilled in this subarea. The most recent geological and geophysical permit was issued on August 29, 1985.

3. Structural traps have been identified throughout the mapped areas east of the base of the continental slope. Stratigraphic traps may be present throughout the areas east of the base of the continental slope.

4. In terms of quantity and quality, the geotechnical data available in the proposed deletion area are sufficient to define specific traps within the nearshore areas. Available data are inadequate for the identification of specific traps west of E73 south of N920 and west of E59 north of N920.

5. Possible exploration/discovery trends within or adjacent to the subarea include northwest trending anticlines adjacent or near the

Deukmejian Deferral, Northern California continued.

San Andreas fault zone, north to northwest oriented antinclinal trends throughout the offshore basins, and the northwest extension of the Tompkins Hill-Table Bluff trend.

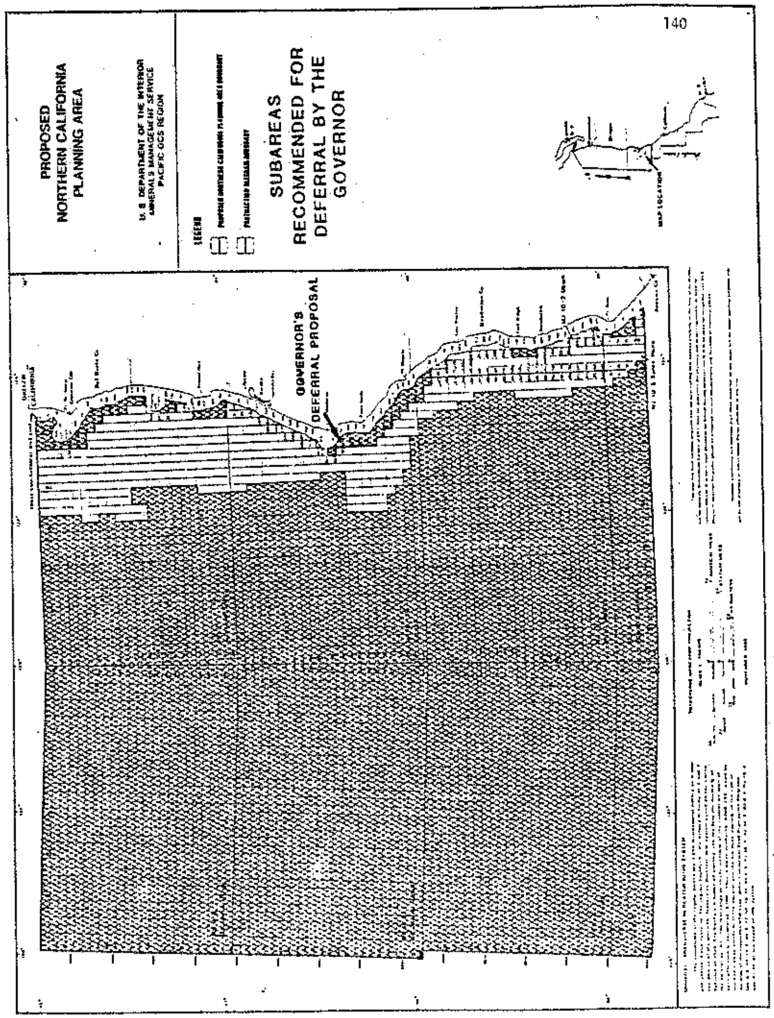
G. Description of the Environment:

The northern California planning area is described in the draft environmental impact statement of the "Proposed 5-Year Outer Continental Shelf Oil and Gas Leasing Program; January 1987 - December 1991" on pages III C-21 to C-38. Additional environmental information for northern California may be found on pages 81 through 86, and pages 180 and 181 of Attachment V to the "Proposed Program" (Decision and Summary) and in the final environmental impact statement for Sale 53 done in September of 1980.

H. Potential Impacts Avoided by Deletion of this Subarea:

The areas requested for deferral would provide zones free of oil and gas development which would provide some protection to the physical, biological, and socioeconomic resources located in them. Further, the deferral of these areas would reduce localized impacts resulting from the construction and operation of the platforms, resources at risk would include water quality, air quality, habitats, cultural resources, and visual resources. In the unlikely event of an oil spill, the deferral areas would provide additional buffering for the resources at risk by providing time for the drifting oil to be dissipated or neutralized through weathering, containment, natural dispersion, and/or chemical dispension.





A. Planning Area:

Southern California.

B. Subarea Name:

Regula Deferral, Southern California.

C. Deferral Recommended By:

Co-Chairman House Negotiations Committee.

D. Geographic Description:

This deferral would affect portions of the entire southern California coastline. This proposal would defer from leasing about seventy-five percent of all the offshore planning areas in California through either 1992 (deep water, beyond the 900 meter isobath) or the year 2000 (nearshore buffer zones adjacent to areas of special biological significance, and State oil and gas sanctuaries). No commercial production would be permitted until 1995. This proposal limits the total number of exploration leases offshore California to 250 in those areas which were subject to the FY 1985 Congressional Moratorium. Significant for Southern California is the incorporation of all deferrals proposed by the Governor of California.

This proposal includes the following deferrals for the Southern California Planning Area:

1. Areas deferred until the year 2000;

   (a) An area consisting of six tiers of blocks extending the entire width of the affected northern portion of the planning area.

   (b) The Santa Barbara Channel Federal Ecological Preserve and Buffer Zone.

   (c) The Channel Islands National Marine Sanctuary.

   (d) The Coordinated Anti-Submarine Warfare Area (San Nicholas Basin).

   (e) A buffer area offshore Santa Monica extending from Point Dume to offshore Long Beach.

   (f) A buffer area offshore Newport Beach to Dana Point.

   (g) A buffer area offshore La Jolla.

   (h) An area offshore San Diego extending south to the provisional maritime boundary with Mexico.



Regula Deferral, Southern California continued.

2. Areas deferred until the year 1992:

   All of the Governor of California's deepwater deferrals except for six tiers of blocks at the northern limit of the planning area which are included in an area deferred until the year 2000 of this proposal.

3. Phased development:

   Two military operating zones, the Camp Pendleton Amphibious Area and the Encinitas Naval Electronics Testing Area, would be made available for leasing on a phased leasing basis under a memorandum of understanding between the Department of Defense and the Department of the Interior. Both military areas would be divided into northern and southern sectors with active leases allowed in only one sector at a time. This leasing arrangement offers the continual availability of a six mile corridor required for military operations.

   For the Camp Pendleton Amphibious Area, the northern sector would be offered first with the southern sector being held for a later sale. For Encinitas Naval Electronics Testing Area, either the northern or southern sector could be offered first (each consisting of two tiers of tracts). As an additional provision only one of two tracts nearest to shore in a sector can be leased at any time.

   Additional military areas covering considerable acreage have been identified offshore southern California. It is expected that most of these areas will be deferred from leasing under a memorandum of understanding between the Department of Defense and the Department of the Interior.

E. Sales and Date Held for which the Subarea was Studied and Disposition in Each Sale:

The area offshore Laguna Beach was studied for Sale 68, but, because of litigation, the tracts were deleted prior to the June 11, 1982 sale. Tracts in the extreme southern portion of this subarea were studied and offered in Sale 80 on October 17, 1984, but no bids were received.

F. Oil and Gas Resource Potential:

1. Parts of this subarea received nominations for Sale 80.

2. No wells have been drilled in this subarea. The most recent geological and geophysical permit was issued on October 28, 1986.

3. Structural traps have been identified throughout most of the area east of the base of the continental slope, with the exceptions of some areas on or near the continental slope west of San Nicolas Island and Santa Lucia Bank. Stratigraphic traps may be present throughout the entire area east of the base of the continental slope.

Regula Deferral, Southern California continued.

Available data are inadequate for the identification of specific traps for areas west of the base of the continental slope and in the areas noted above.

4. In terms of quantity and quality, the geotechnical data available in the proposed deletion area are sufficient to define specific traps within the nearshore areas and the San Nicolas and Velero basins.

5. Possible exploration/discovery trends within or adjacent to the subarea from south to north include the Newport-Inglewood, Wilmington-Torrance, Palos Verdes fault, Venice Beach-El Segundo, Beverly Hills-Sawtelle, Hueneme-Sockeye, Santa Clara-Santa Rosa, Montalvo, Pitas Point, Rincon-Dos Cuadras, South Elwood, and Hosgri fault trends.

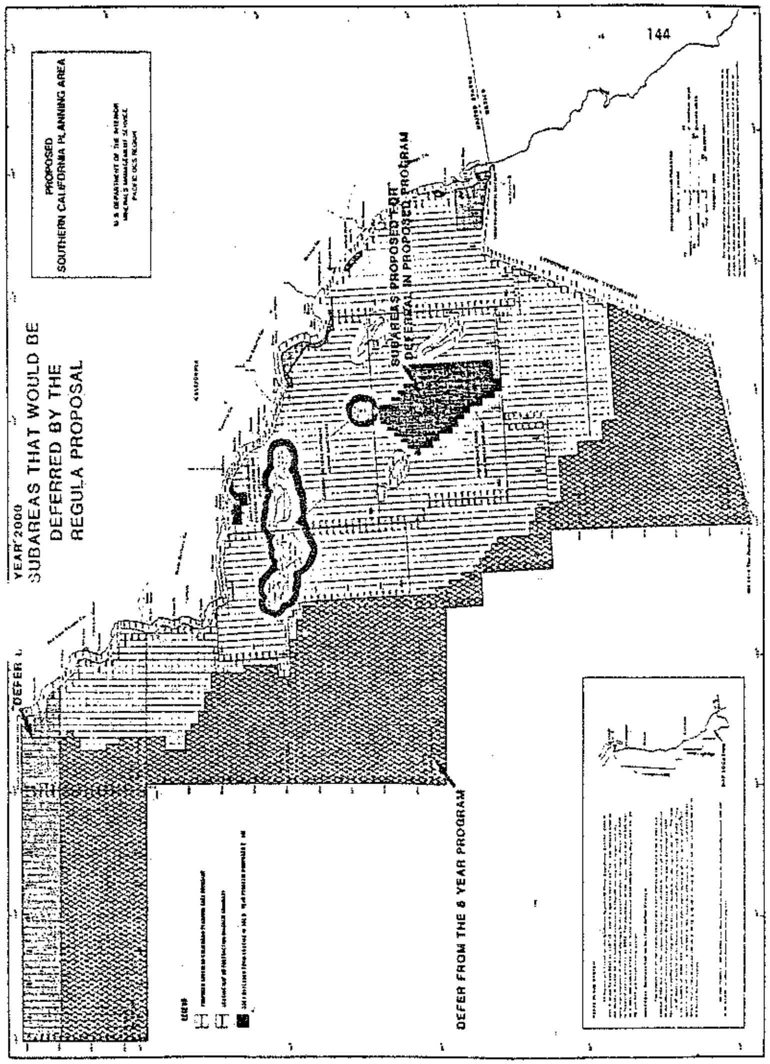
G. Description of the Environment:

The Southern California Planning Area is described in the draft environmental impact statement of the "Proposed 5-Year Outer Continental Shelf Oil and Gas Leasing Program; January 1987-December 1991" pages III C-53 to C-73. A description of the environment may also be found on pages 97 through 134 of Attachment V to the "Proposed Program" (Decision and Summary) and in the environmental impact statement for Sale 80 which was done in April of 1984.

H. Potential Impacts Avoided by Deletion of this Subarea:

The areas requested for deferral would provide zones free of oil and gas development which would provide some protection to the physical, biological, military, and socioeconomic resources located in them. Further, the deferral of these areas would reduce localized impacts resulting from the construction and operation of the platforms. resources at risk would include water quality, air quality, biological habitats, commercial fisheries, cultural resources, and visual resources. In the unlikely event of an oil spill, the deferral areas would provide additional buffering for the resources at risk by providing time for the drifting oil to be dissipated or neutralized through weathering, containment, natural dispersion, and/or chemical dispersion.





A. Planning Area:

Central California.

B. Subarea Name:

Regula Deferral, Central California.

C. Deferral Recommended By:

Co-Chairman House Negotiations Committee.

D. Geographic Description:

This deferral would affect portions of the entire central California coastline. This proposal would defer from leasing about seventy-five percent of all the offshore planning areas in California through either 1992 (deep water, beyond the 900 meter isobath) or the year 2000 (nearshore buffer zones adjacent to areas of special biological significance, and State oil and gas sanctuaries). No commercial production would be permitted until 1995. This proposal limits the the total number of exploration leases offshore California to 250 in those areas which were subject to the FY 1985 Congressional Moratorium.

Significant for central California is the incorporation of virtually all of the Governor's deferral recommendations, the subarea deferrals incorporated by the Secretary of the Interior in the Proposed 5-Year Program, and buffer zones offered in this proposal. Taken together these deferrals address the full extent of the central California coast.

1. Areas deferred until the year 2000 (from north to south):

(a) A buffer zone from offshore the Mendocino/Sonoma County line to near Bodega Head.

(b) The area offshore Point Reyes Wilderness and the Point Reyes-Farallon Islands National Marine Sanctuary. The former area includes Federal waters within 15 miles of the wilderness area. The portion of the Point Reyes-Farallon Islands Sanctuary not overlapping with the Point Reyes Wilderness subarea extends at least 12 nautical miles from the Farallon Islands.

(c) The area in the immediate vicinity of Cordell Bank.

(d) The area offshore San Francisco Bay.

(e) A buffer zone offshore the San Francisco/San Mateo county line south to near Monterey Bay.



Regula Deferral, Central California continued.

(f) An extensive triangular area offshore Monterey Bay, Big Sur and south to Cape San Mateo which contains in excess of 2.5 million acres.

2. Areas deferred until the year 1992:

(a) All of the Governor of California's deepwater deferral. (Portions of the Governor's deferral which are offshore Big Sur are included in the area deferred until the year 2000 in this proposal.)

E. Sales and Date held for which the Subarea was Studied and Disposition in Each Sale:

This subarea was studied for Sale 53, however the subarea was deferred prior to the Sale.

F. Oil and Gas Resource Potential:

1. Parts of this subarea were nominated for Sale 73.

2. No wells have been drilled in this subarea. The most recent geological and geophysical permit was issued on October 28, 1986.

3. Structural traps have been identified throughout the mapped areas east of the base of the continental slope. Stratigraphic traps may be present throughout the area east of the base of the continental slope.

4. In terms of quantity and quality, the geotechnical data available in the proposed deletion area are sufficient to define specific traps within the nearshore areas. Available data are inadequate for the identification of specific traps in most areas southwest of a line from N826/E120 to N895/E80.

5. Possible exploration/discovery trends within or adjacent to the subarea include the Hosgri-Sur-Nacimiento-Palo Colorado-San Gregorio fault zones and associated anticlines which extend northwest-southeast throughout the area, northwest-oriented anticlinal trends in Ano Nuevo, La Honda and Bodega basins which have been partially explored by industry, the San Andreas fault zone and associated anticlines which trend northwestward along the northeastern edge of the area, and the Drakes Bay-Bolinas trend in the La Honda basin.

G. Description of the Environment:

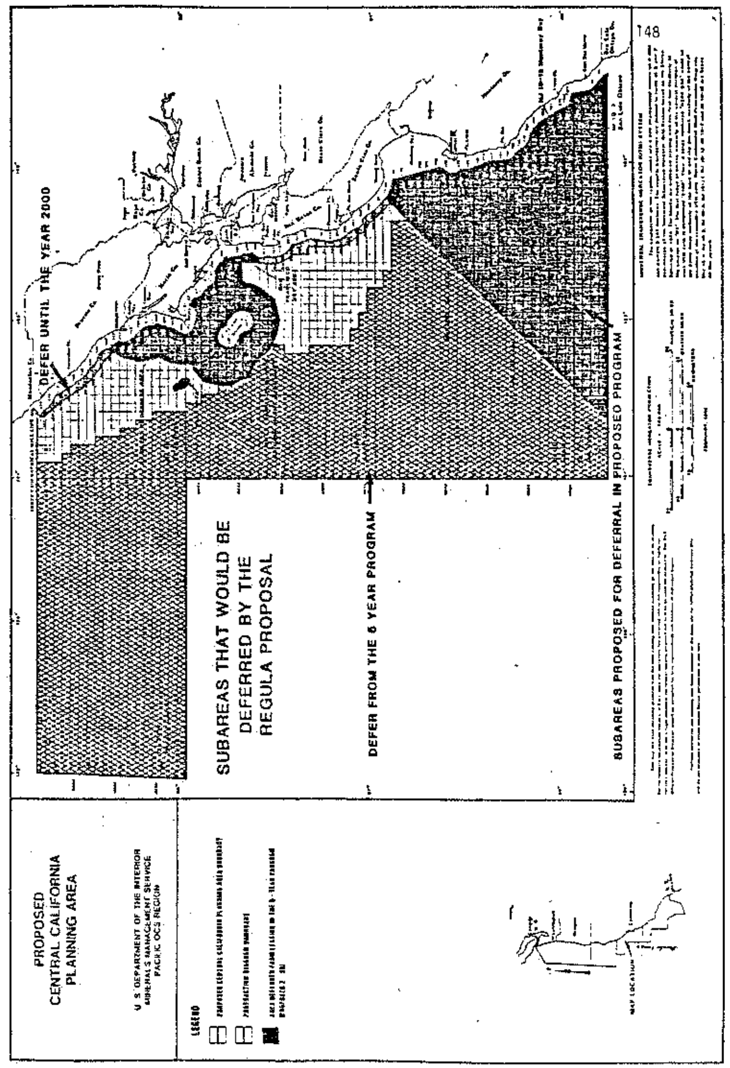
The central California planning area is described in the draft environmental impact statement of the "Proposed 5-Year Outer Continental Shelf Oil and Gas Leasing Program: January 1992 - December 1991" pages III C-39 to C-52. Additional environmental information for

Regula Deferral, Central California continued.

central California may be found on pages 70 through 79 of Attachment V to the "Proposed Program" (Decision and Summary) and in the final environmental impact statement for Sale 73 done in June of 1983.

H. Potential Impacts Avoided by Deletion of this Subarea:

The areas requested for deferral would provide zones free of oil and gas development which would provide some protection to the physical, biological, and socioeconomic resources located in them. Further, the deferral of these areas would reduce localized impacts resulting from the construction and operation of the platforms. Environmental resources at risk would include water quality, air quality, biological habitats, cultural resources, commercial fisheries and visual resources. In the unlikely event of an oil spill, the deferral areas would provide additional buffering for the resources at risk by providing time for the drifting oil to be dissipated or neutralized through weathering, containment, natural dispersion, and/or chemical dispersion.



A. Planning Area:

Northern California.

B. Subarea Name:

Regula Deferral, Northern California.

C. Deferral Recommended By:

Co-Chairman House Negotiations Committee.

D. Geographic Description:

This deferral would affect portions of the entire northern California coastline. This proposal would defer from leasing about seventy-five percent of all the offshore planning areas in California through either 1992 (deep water, beyond the 900 meter isobath) or the year 2000 (nearshore buffer zones adjacent to areas of special biological significance, and State oil and gas sanctuaries). No commercial production would be permitted until 1995. This proposal limits the total number of exploration leases offshore California to 250 in those areas which were subject to the FY 1985 Congressional Moratorium.

Significant for Northern California is the incorporation of virtually all of the Governor's deferral recommendations, and the area off Cape Mendocino and Punta Gorda. This proposal includes the following deferrals for the Northern California planning area:

1. Areas deferred until the year 2000:

(a) Buffer zones 5 miles offshore the seaward boundaries of Areas of Special Biological Significance as specified in the Governor's proposal including:
- immediately north and south of Redding Rock
- southwest of Trinidad Head
- southwest of Point Delgada
- southwest of Fort Bragg
- south of Point Arena.

(b) An expansive deferral offshore Cape Mendocino and Punta Gorda extending from the shoreward limit of the deepwater deferral to the boundary of state and federal waters.

2. Areas deferred until the year 1992:

(a) All deepwater areas suggested for deferral by the Governor of California except for 11 blocks of industry interest. Most of this area, including the industry interest blocks, lies seaward of the 900 meter isobath.



Regula Deferral, Northern California continued.

(b) All blocks located north of Trinidad Head to the Oregon border. This area extends shoreward from the Governor's deepwater deferral to the coast or to the seaward edge of buffer zones.

E. Sales and Date Held for which the Subarea was Studied and Disposition in Each Sale:

Lease Sale P1 was held in Central and Northern California on May 14, 1963. Seventeen tracts southwest of Crescent City were leased, but all leases were relinquished prior to their expiration. No environmental impact statement was required to be prepared for Sale P1. This area was studied for possible inclusion in Lease Sale 53 held on May 28, 1991; however, no tracts were offered in the Northern California Planning Area.

F. Oil and Gas Resource Potential:

1. Parts of this subarea have been nominated for Proposed Sale 91 and and other parts were nominated for Sale 73.

2. Four wells were drilled on the Sale P1 leases. There were no shows of hydrocarbons in any of the wells. The most recent geological and geophysical permit in this subarea was issued on October 28, 1986.

3. Structural traps have been identified throughout the mapped areas east of the base of the continental slope. Stratigraphic traps may be present throughout the areas east of the base of the continental slope.

4. In terms of quantity and quality, the geotechnical data available in the proposed deletion area are sufficient to define specific traps within the near shore areas. Available data are inadequate for the identification of specific traps west of E78 south of N920 and west of E69 north of N920.

5. Possible exploration/discovery trends within or adjacent to the subarea include northwest trending anticlines adjacent to or near the San Andreas fault zone, north to northwest oriented anticline trends throughout the offshore basins, and the northwest extension of the Tompkins Hill-Table Bluff trend.

G. Description of the Environment:

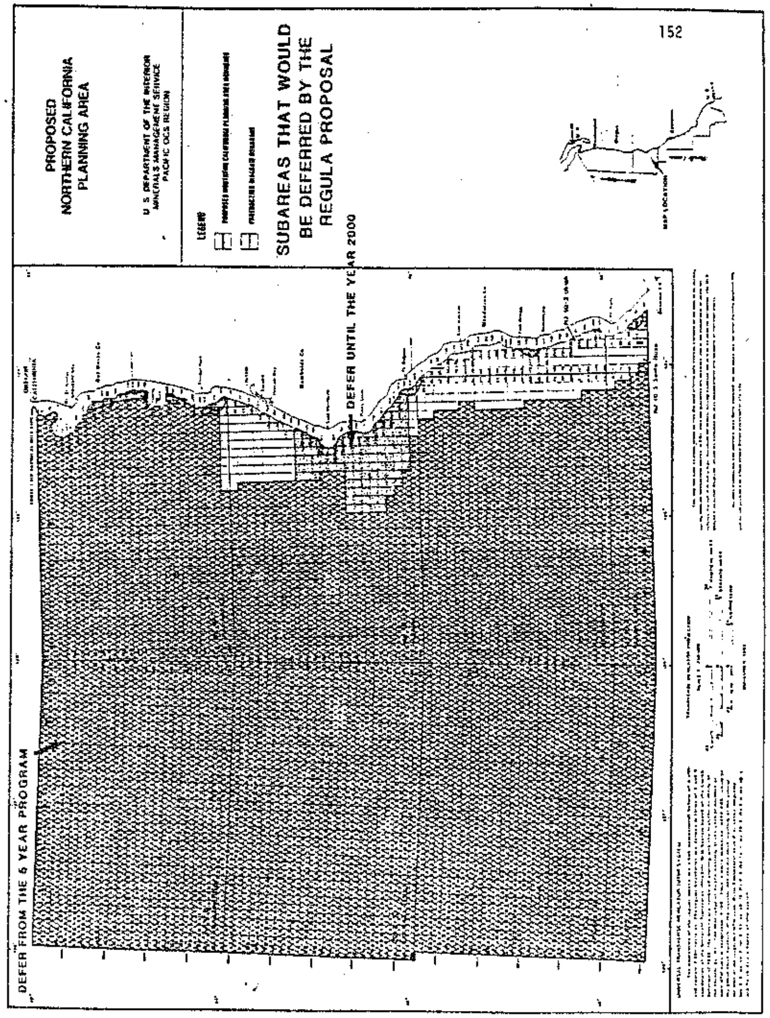
The Northern California Planning Area is described in the draft environmental impact statement of the "Proposed 5-Year Outer Continental Shelf Oil and Gas Leasing Program; January 1987-December 1991" pages III C-21 to C-38. Additional environmental information for northern California may be found on pages 31 through 36, and pages 180 and 131 of Attachment V to the "Proposed Program" (Decision and Summary) and in the final environmental impact statement for Sale 53 done in September of 1980.

Regula Deferral, Northern California continued.

H. <u>Potential Impacts Avoided by Deletion of this Subarea</u>:

The areas requested for deferral would provide zones free of oil and gas development which would provide some protection to the physical, biological, and socioeconomic resources located in them. Further, the deferral of these areas would reduce localized impacts resulting from the construction and operation of the platforms. Environmental resources at risk would include water quality, air quality, biological habitats, cultural resources, and visual resources. In the unlikely event of an oil spill, the deferral areas would provide additional buffering for the resources at risk by providing time for the drifting oil to be dissipated or neutralized through weathering, containment, natural dispersion, and/or chemical dispersion.





A. Planning Area:

Southern California.

B. Subarea Nam:

Panetta Deferral, Southern California.

C. Deferral Recommended By:

Congressman Leon Panetta.

D. Geographic Description:

This deferral would affect portions of the entire southern California coastline. It would create a buffer area three to eighteen miles offshore where no leasing would be allowed until the year 2000. This proposal allows offering for lease only 173 blocks, generally comprised of industry interest blocks, outside the buffer zone on a phased basis. No more than 50 blocks of the 173 may be offered during mid-1987 through mid-1992. Any or all blocks outside the buffer zone, excluding the 173 blocks subject to phased leasing, maybe offered for lease. Eighty-nine of the 173 blocks identified by Congressman Panetta are in the Southern California Planning Area.

E. Sales and Date Held for Which the Subarea was Studied and Disposition in Each Sale:

Portions of this area were studied for Sale 35, held December 11, 1975, and nine tracts offshore Long Beach were leased. Two leases remain active. Parts of the area were also studeid for Sale 48 held on June 29, 1979; however, the one tract that was bid on, offshore Costa Mesa, was rejected becuase of insufficiency. Tracts were also studied for Sale 68, held June 11, 1982, and one block offshore Huntington Beach has leased and remains active. The entire southern part of this subarea was studied in the Sale 80 areawide environmental impact statement, but the area was defered because of the Congressional moratorium, prior to the October 17, 1984, sale.

F. Oil-and-Gas-Resource-Potential:

1. The southern portion of the subarea received nominations for Sale 80 and the northern portion of the subarea was nominated for Sale 73.

2. Four exploratory wells were drilled in this subarea as a result of Sale 35, however, no discoveries were announced. The most recent geological and geophysical permit was issued on October 28, 1986.

3. Structural traps have been identified throughout the mapped area. Stratigraphic traps may also be present throughout the entire area.

4. In terms of quantity and quality, the geotechnical data available in the proposed deletin area are sufficient to define specific traps throughout the entire area.



Panetta Deferral, Southern California continued.

5. Possible exploration/discovery trends within or adjacent to the subarea from south to north include the Newport-Inglewood, Wilmington-Torrance, Palos Verdes fault, Venice Beach-El Segundo, Beverly Hills-Sawtelle, and Hosgri fault trends.

G. Description of the Environment:

The southern California planning area is described in the draft environmental impact statement of the "Proposed 5-Year Outer Continental Shelf Oil and Gas Leasing Program; January 1987-December 1991" starting on page III C-53 to C-73. A description of the environment may also be found on pages 97 through 184 of Attachment V to the "Proposed Program" (Decision and Summary) and in the environmental impact statement for Sale 80 which was done in April of 1984.

H. Potential Impacts Avoided by Deletion of this Subarea:

The areas requested for deferral would provide zones free of oil and gas development which would provide some protection to the physical, biological, and socioeconomic resources located in them. Further, the deferral of these areas would reduce localized impacts resulting from the construction and operation of the platforms. Environmental resources at risk would include water quality, air quality, biological habitats, cultural resources, commercial fisheries, and visual resources. In the unlikely event of an oil spill, the deferral areas would provide additional buffering for the resources at risk by providing time for the drifting oil to be dissipated or neutralized through weathering, containment, natural dispersion, and/or chemical dispersion.