TENTATIVE PROPOSED FINAL 5-YEAR OCS LEASING PROGRAM

(1982-1987)

U.S. Department of the Interior
Office of OCS Program Coordination
March 1, 1982

United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

MAR 1

Memorandum

To: The Secretary

Through: Executive Secretariat

From: Assistant Secretary--Policy, Budget and Administration

Subject: Adoption of a Tentative Proposed Final 5-Year OCS Oil and Gas Leasing Program

BACKGROUND

Section 18 of the OCS Lands Act, as amended, requires you to prepare, periodically revise and maintain an oil and gas leasing program for the U.S. Outer Continental Shelf (OCS). It also requires, among other things, that "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 [the Secretary] determines will best meet national energy needs for the five-year period following its approval or reapproval."

The Department is now engaged in a reapproval process in order to develop and put in place a new 5-year leasing program replacing the 5-year program approved in June 1980. The next step in that process, as ordered by the D.C. Circuit Court of Appeals, is submission, in mid-March, of a tentative proposed final leasing program to the Congress, the Attorney General and the Governors of affected States, and publication of it in the Federal Register.

A Secretarial Issue Document (SID) has been prepared to present factors for your consideration in selecting an OCS oil and gas leasing program. Consideration of these factors is required by section 18 of the OCS Lands Act, and the D.C. Circuit Court of Appeals ruling of October 6, 1981. The SID is the result of an extensive Department-wide cooperative effort involving BLM, MMS, GS, FWS, Solicitor, and units in PBA.

In reviewing the SID, it is important to keep in mind that the quantitative aspects of the analysis are subject to considerable uncertainty. Net economic value, the difference between product price and all the costs leading to production and transportation to market, is uncertain because outside the Central and Western Gulf of Mexico, the inventorying of resources by drilling has either not started, or has just barely begun. Also, costs are uncertain in frontier areas due to a lack of experience there. External costs, the estimated social and environmental costs which might result from production, are uncertain because there is no commonly accepted method for assigning economic values to non-market goods, and because certain intrinsic values cannot be assigned dollar values at all. Nevertheless, the difference between estimated net economic value and estimated external costs, which is expected net social value, is so large that in every planning area the external costs would have to be many times larger than estimated in order to reduce the expected net social value to zero. In one instance, the expected net social value is about 20 times larger than the estimated external costs. In every other case, the difference is larger.

It is also necessary to view Alaska in the proper perspective when you are determining the role the Alaskan OCS should play in the national program. While Alaska is only one State, its OCS contains 30% of the remaining OCS hydrocarbon resources, 57% of the acreage of the promising areas and its coastline is one-third greater than the coastline of the entire contiguous 48 States. In light of these statistics, it is not surprising that 38% of the sales included in the July 1981 proposed program are located off Alaska.

A final supplemental environmental impact statement (FSEIS), has been prepared by BLM which assesses the environmental effects of alternative schedules and the streamlined lease procedures which you adopted as part of the July 1981 proposed program.

Attached for your reference are the following items:

Attachment A: Schedule options and maps of OCS planning areas.

Attachment B: Secretarial Issue Document and Appendices on Tentative Proposed Final 5-Year OCS Oil and Gas Leasing Program

Attachment C: Final Supplemental Environmental Impact Statement on 5-Year Leasing Schedule

SECTION 18 ANALYSIS

The program you select must "...consist of a schedule of proposed lease sales indicating, as precisely as possible, the size, timing and location of leasing activity...." In selecting such a program, you are required to consider, and base your program on a wide range of factors identified in section 18. The following discussions of size, timing and location of leasing incorporate the required factors.

1. Size

Possibilities for defining lease offerings include: (1) tract selection with traditional sale size, (2) tract selection with larger sales, and (3) area-wide offerings. The size of sales included in the proposed program issued in July 1981 assumed area-wide lease offerings. On December 15, 1981, you made a preliminary decision to refine that concept. Under the refined concept, the Department would announce its intention to offer entire planning areas for lease. In preparing for OCS offerings, the BLM would focus analysis on those portions of a planning area which MMS, GS, the oil and gas industry and others believe have the potential for the discovery of oil and gas, and BLM would provide an environmental description of the entire area. Our analysis indicates that the refined concept will not change the national benefits resulting from the program but will slightly reduce the budgetary needs of MMS.

The SID analysis shows that larger sale sizes result in significantly larger net social value accruing to the Nation. Part III of the SID analyzes alternative lease schedules under different possible sale sizes. Appendix 2 to the SID analyzes the economic effects of different sale sizes and Appendix 3 analyzes the effects of sale size on assuring the receipt of fair market value. Chapter III of the FSEIS includes estimates of acreage leased.

2. Timing and Location

Your decision regarding the timing and location of leasing needs to reflect consideration of the factors listed in § 18(a)(1), 18(a)(2) and 18(a)(3). The SID addresses all of these factors and reaches a number of conclusions from the quantitative aspects of the analyses which are described in Part III.E.

Location deals with the question of whether a particular planning area should be included in a program which would result in the initiation or continuation of planning for a sale. The quantitative analysis provides a way of approaching this question--if the expected benefits of oil and gas production in an area exceed the estimated costs, the area should be included in the schedule. The analysis shows that this is the case for each of the 18 areas included in the July 1981 schedule.

Similarly, with respect to timing, the net social value calculations can be used as a guide in deciding the frequency of offerings and timing of first offering. With respect to any final determination on timing and location, all of the qualitative aspects of § 18(a)(2) will need to be reviewed collectively to determine whether the judgments derived from the net social value calculations should be modified.

By considering the quantitative analysis of the section 18 factors, we have been able to develop an additional alternative schedule which should be considered as one example of "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 example would provide for annual offerings in the Central and Western Gulf of Mexico, biennial offerings in the North Atlantic, South Atlantic, Eastern Gulf of Mexico, Southern California, Central and Northern California, North Aleutian Basin, St. George Basin, Norton Basin, Barrow Arch and the Diapir Field; and later and only one offering in the Gulf of Alaska, Kodiak, Cook Inlet, Shumagin and Hope Basin. It is noteworthy that while this example is different than the July 1981 proposal in some respects, the differences do not appear to be large. The example was derived solely from the quantitative analyses, and does not reflect your judgment of the many qualitative factors you are required to consider under section 18.

We received numerous comments on the July proposed program with respect to the timing and location of sales. A detailed summary of these comments appears in Appendix 6 to the SID. Highlights of their comments follow.

-- South Carolina and Florida have requested that sale 78 - South Atlantic be delayed in order to allow experience gained from exploration of sale 56 tracts to be considered. Sale 78 is proposed for July 1983 in the proposed program.

-- California recommends deletion of several basins or portions of basins off its coast.

-- Alaska recommends (1) deletion of North Aleutian Basin and St. George Basin sales, (2) delay of sales in Hope Basin, Norton Basin and Navarin Basin until 1984-1985 to allow completion of local coastal management programs and progress in developing exploration and development techniques, transportation methods, or measures to mitigate potentially adverse effects, and (3) indefinite postponement of sales in Barrow Arch and the offshore pack ice zone of the Diapir Field until there is a comprehensive environmental data base for development of appropriate regulatory mechanisms and a more advanced technological capability for arctic waters.

Several industry commenters also suggested schedule changes which have been analyzed by MMS. The one suggestion which the MMS found to have merit was to change the sale date for sale 71 - Diapir Field to allow industry to take advantage of the 1982 summer seismic season. A change from September to late November 1982 would accomplish this. Unfavorable ice conditions occur one summer season about every 2 or 3 years. Despite the possibility that the 1982 summer season might be unsuccessful, MMS favors the change because of the severe effect of seasonal constraints on seismic work in the Beaufort.

Part III of the SID contains an analysis of the five schedules included in the FSEIS based on factors you are to consider under section 18. These schedules include: (1) the July 1981 proposed program, (2) the March 1981 draft proposed program, (3) the June 1980 program, (4) the proposed program with certain Alaska sales delayed, accelerated or deferred, and (5) the proposed program with arctic sales deferred. The net social value estimates for these schedules do not vary markedly because of timing and location considerations. Changes in sale size appear to have much more of an effect on net social value. However, while the differences resulting from timing and location changes are not as large as differences resulting from area-wide offerings, they are signficant because they provide a means for ranking various schedule alternatives. Also, it is important to remember that net social values are based on USGS resource estimates. Industry rankings of planning areas offshore Alaska indicate that they place higher interest in several of the areas off Alaska than does USGS. If their interpretations are correct, the losses associated with delaying or deleting Alaskan sales would likely be greater than shown in the analysis. Because all of the required factors involve degrees of judgment, the decisionmaking process is by no means deterministic. Your policy judgments are important in this regard as the court recognized in its decision of October 6, 1981.

1987 SALES

Since final approval of the program is not expected to occur until July 1982, sales will need to be added for the first half of 1987. This is because the program is to cover a full 5-year period. The sales proposed for 1987 should be consistent with the pattern of leasing in preceding years.

TECHNICAL ADJUSTMENTS TO THE PROPOSED PROGRAM

Since the decision was made on the July 1981 proposed program, several technical adjustments have been proposed to address both administrative and technical questions. These adjustments are covered in part IV of the SID and are listed below.

Planning Area Boundary Changes

BLM, MMS and GS recommend that the planning area boundaries used in the proposed program be changed as follows:

1. Atlantic

The boundary between the North and South Atlantic should be moved from Cape Charles, Virginia, to Cape Hatteras, North Carolina. This change would correspond to the geologically most appropriate division of the planning areas. The change was also recommended by New York.

2. California

The seaward boundary for the California planning areas should conform to the borders of Official Protraction Diagrams (OPD's) which correspond approximately to the 3,000-meter isobath. This would increase the acreage in the California planning areas from 57 million acres to 59.1 million acres.

3. Alaska

To better delineate areas of oil and gas potential, the boundary between the Barrow Arch and Hope Basin planning areas should be at Point Hope rather than along 69 degrees N. latitude. For the same reason, the southern boundary of the Cook Inlet area should extend along the 57 degree N. latitude line between OPD's NO 4-6 and NO 4-8.

In order not to divide OPD's unnecessarily, the boundary between Kodiak and Gulf of Alaska should run along the 147 degree longitude line between OPD's NO 6-5 and NO 6-6, between OPD's NO 6-7 and NO 6-8, and between OPD's NN 6-1 and NN 6-2. In order to conform to the Canadian boundary line, the southern boundary of the Gulf of Alaska area bisects OPD's NN 7-3, NN 7-4, NN 8-3 and NN 8-4.

Timing Changes

1. RS-2 must be rescheduled for July 1982 due to the delay in a decision on the proposed Notice of Sale.

2. #73 - Central and Northern California must be delayed 8 months (from January to September 1983) due to the delay in a decision on Area Identification.

Location Changes

Sales #90 and #96 - Atlantic are changed to South Atlantic and North Atlantic respectively, in response to the D.C. Circuit Court of Appeals decision.

OPTIONS FOR DECISION

You are being asked to (1) determine the scope of offerings, (2) select a schedule of lease sales for the 5-year period July 1982 through June 1987 and (3) adopt a number of technical adjustments. The alternative ways of defining offerings include traditional size tract selection, tract selection with larger than traditional offerings, and area-wide offerings. There are two suboptions under area-wide offerings. Six alternative schedules have been analyzed. You may adopt one of these or some variation thereof as long as the variation is within the range of the alternatives analyzed in the FSEIS. The sales you propose for 1987 should be consistent with the pattern of leasing in preceding years.

Attachments

DECISION SHEET

Tentative Proposed Final 5-Year OCS Oil and Gas Leasing Program

I. Ways of Defining Scope of Offerings for NEPA Analysis

A. Tract Selection with traditional size offerings ______

B. Tract Selection with larger offerings ______

C. Area-wide Offerings ______

1. As described in July 1981 program ______

2. As described in preliminary refinement of December 15, 1981 ______

D. Other ______

II. Alternative Schedules

A. Proposed Program (July 1981) ______

B. Draft Proposed Program (April 1981) ______

C. June 1980 Program ______

D. Modify Proposed Program by Delaying, Deferring and Accelerating Alaskan Sales ______

Delay: Sale #70-St. George Basin from 1983 to 1986
Sale #83-Navarin Basin from 1984 to 1985
Sale #85-Barrow Arch from 1985 to 1986
Sale #86-Hope Basin from 1985 to 1986

Defer: Sales #75 and #92-North Aleutian Basin (1983 & 1985)
Sale #88-Norton Basin (1984)
Sales #89 and #101-St. George Basin (1984 & 1986)
Sale #107-Navarin Basin (1986)

Accelerate: Sale #100-South Alaska from 1985 to 1984
Sale #97-Diapir Field from 1986 to 1985

E. Modify Proposed Program by Deferring Arctic Sales ______

Defer: Sales #71, #87, #97-Diapir Field (1982, 1984, 1986)
Sale #85-Barrow Arch (1985)
Sale #86-Hope Basin (1985)

F. Sample Program ______

G. Other ______

III. 1987 Sales

A. South Atlantic, Barrow Arch, C. Gulf of Mexico, Hope Basin ______

B. Other ______

IV. Technical Adjustments

A. Change Atlantic, California and Alaskan Boundaries as Discussed in SID ______

B. Timing Changes

1. Delay RS-2 from June to July 1982 ______

2. Delay #73 from January to September 1983 ______

C. Designate #90 and #96 as North Atlantic and South Atlantic, respectively ______

D. Other ______

____
Secretary of the Interior

____
Date

Schedule Options

Alt. I-1 and I-2

1982

67 Gulf of Mexico
68 S. California
RS-2
52 N. Atlantic
71 Diapir Field
69 Gulf of Mexico
57 Norton Basin

1983

73 C&N California
70 St. George Basin
76 Mid Atlantic
75 N. Aleutian Basin
72 C. Gulf of Mexico
78 S. Atlantic
74 W. Gulf of Mexico
79 E. Gulf of Mexico

1984

80 S. California
82 N. Atlantic
83 Navarin Basin
81 C. Gulf of Mexico
87 Diapir Field
84 W. Gulf of Mexico
88 Norton Basin
94 E. Gulf of Mexico
89 St. George Basin

1985

90 Atlantic
85 Barrow Arch
91 C&N California
92 N. Aleutian Basin
98 C. Gulf of Mexico
86 Hope Basin
102 W. Gulf of Mexico
100 S. Alaska
103 E. Gulf of Mexico

1986

95 S. California
96 Atlantic
107 Navarin Basin
104 C. Gulf of Mexico
97 Diapir Field
105 W. Gulf of Mexico
99 Norton Basin
106 E. Gulf of Mexico
101 St. George Basin

Alt. II

1982

67 Gulf of Mexico
68 S. California
57 Norton Basin
RS-2
52 North Atlantic
71 Diapir Field
69 Gulf of Mexico
70 St. George Basin

1983

73 California
76 Mid Atlantic
75 N. Aleutian Basin
72 Gulf of Mexico
RS-3
78 S. Atlantic
74 Gulf of Mexico
83 Navarin Basin

1984

80 California
82 N. Atlantic
87 Diapir Field
79 Gulf of Mexico
88 Norton Basin
RS-4
89 St. George Basin
81 Gulf of Mexico

1985

85 Barrow Arch
90 Atlantic
91 California
84 Gulf of Mexico
RS-5
92 N. Aleutian Basin
86 Hope Basin
93 St. Matthew Hall
94 Gulf of Mexico

1986

95 California
96 Atlantic
97 Diapir Field
98 Gulf of Mexico
RS-6
99 Norton Basin
100 S. Alaska
101 St. George Basin
102 Gulf of Mexico

Alt. III-1 and III-2

1982

67 Gulf of Mexico
RS-2
68 S. California
69 Gulf of Mexico
57 Norton Basin
52 North Atlantic
70 St. George Basin

1983

71 Diapir Field
72 Gulf of Mexico
73 California
RS-3
74 Gulf of Mexico
75 N. Aleutian Basin
76 Mid Atlantic

1984

78 South Atlantic
79 Gulf of Mexico
RS-4
80 California
81 Gulf of Mexico
82 N. Atlantic
83 Navarin Basin

1985

84 Gulf of Mexico
85 Barrow Arch
86 Hope Basin
RS-5

Alt. IV-1 and IV-2

1982

67 Gulf of Mexico
68 S. California
RS-2
52 North Atlantic
71 Diapir Field
69 Gulf of Mexico
57 Norton Basin

1983

73 C&N California
76 Mid Atlantic
72 C. Gulf of Mexico
78 S. Atlantic
74 W. Gulf of Mexico
79 E. Gulf of Mexico

1984

80 S. California
82 N. Atlantic
81 C. Gulf of Mexico
87 Diapir Field
84 W. Gulf of Mexico
100 S. Alaska
94 E. Gulf of Mexico

1985

90 Atlantic
91 C & N California
98 C. Gulf of Mexico
83 Navarin Basin
102 W. Gulf of Mexico
97 Diapir Field
103 E. Gulf of Mexico

1986

95 S. California
96 Atlantic
70 St. George Basin
104 C. Gulf of Mexico
99 Norton Basin
105 W. Gulf of Mexico
85/86 Hope/Barrow
106 E. Gulf of Mexico

Alt. V-1 and V-2

1982

67 Gulf of Mexico
68 S. California
RS-2
52 North Atlantic
69 Gulf of Mexico
57 Norton Basin

1983

73 C&N California
70 St. George Basin
76 Mid Atlantic
75 N. Aleutian Basin
72 C. Gulf of Mexico
78 S. Atlantic
74 W. Gulf of Mexico
79 E. Gulf of Mexico

1984

80 S. California
82 N. Atlantic
83 Navarin Basin
81 C. Gulf of Mexico
84 W. Gulf of Mexico
88 Norton Basin
94 E. Gulf of Mexico
89 St. George Basin

1985

90 Atlantic
91 N & C California
92 N. Aleutian Basin
98 C. Gulf of Mexico
102 W. Gulf of Mexico
100 S. Alaska
103 E. Gulf of Mexico

1986

95 S. California
96 Atlantic
107 Navarin Basin
104 C. Gulf of Mexico
105 W. Gulf of Mexico
99 Norton Basin
106 E. Gulf of Mexico
101 St. George Basin

Sample Program

1982

RS-2
52 N. Atlantic
71 Diapir Field
69 Gulf of Mexico
57 Norton Basin

1983

70 St. George Basin
76 Mid-Atlantic
75 N. Aleutian Basin
72 C. Gulf of Mexico
78 S. Atlantic
74 W. Gulf of Mexico
73 C & N California
79 E. Gulf of Mexico

1984

80 S. California
82 N. Atlantic
83 Navarin Basin
81 C. Gulf of Mexico
87 Diapir Field
84 W. Gulf of Mexico
88 Norton Basin
89 St. George Basin

1985

90 S. Atlantic
85 Barrow Arch
92 N. Aleutian Basin
98 C. Gulf of Mexico
102 W. Gulf of Mexico
91 C & N California
100 S. Alaska
94 E. Gulf of Mexico

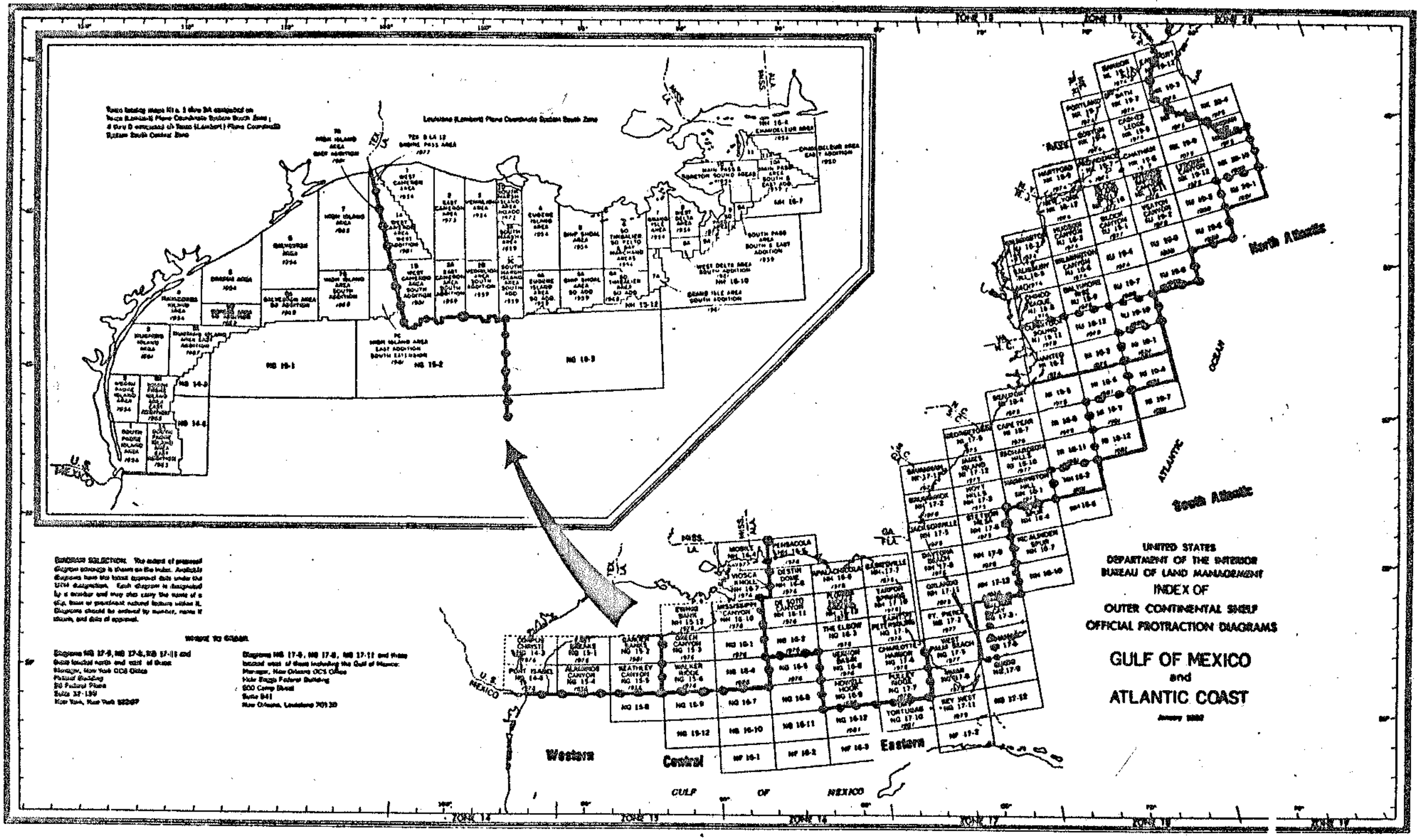
1986

95 S. California
96 N. Atlantic
107 Navarin Basin
104 C. Gulf of Mexico
97 Diapir Field
105 W. Gulf of Mexico
99 Norton Basin
101 St. George Basin

1987

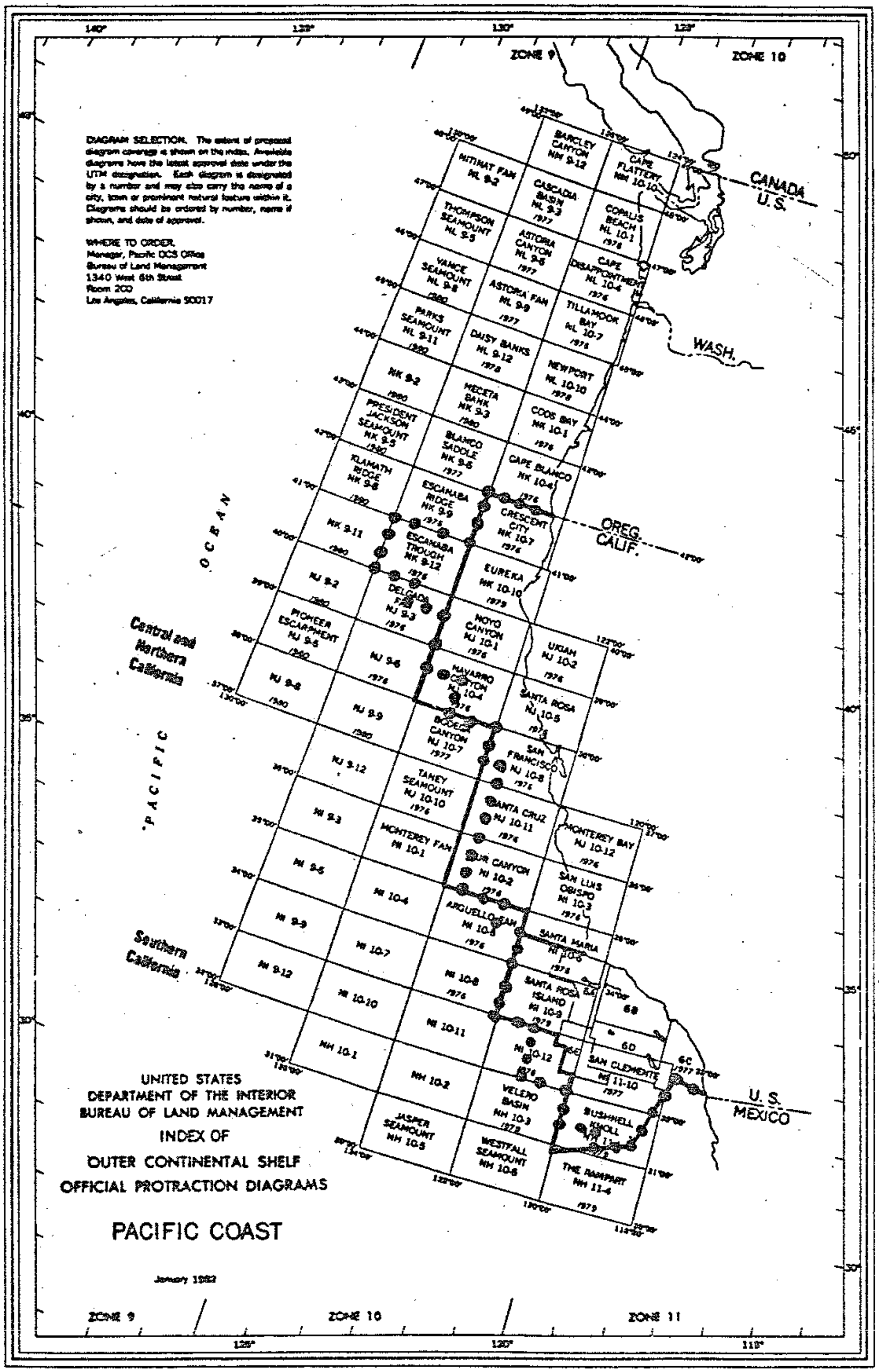
S. Atlantic
Barrow Arch
C. Gulf of Mexico
Hope Basin

Atlantic and Gulf of Mexico Planning Areas



- • • • • • • July 1981 planning area boundary
- ——— proposed boundary adjustment
- •—•—•—• boundary unchanged from July 1981 boundary

California Planning Areas



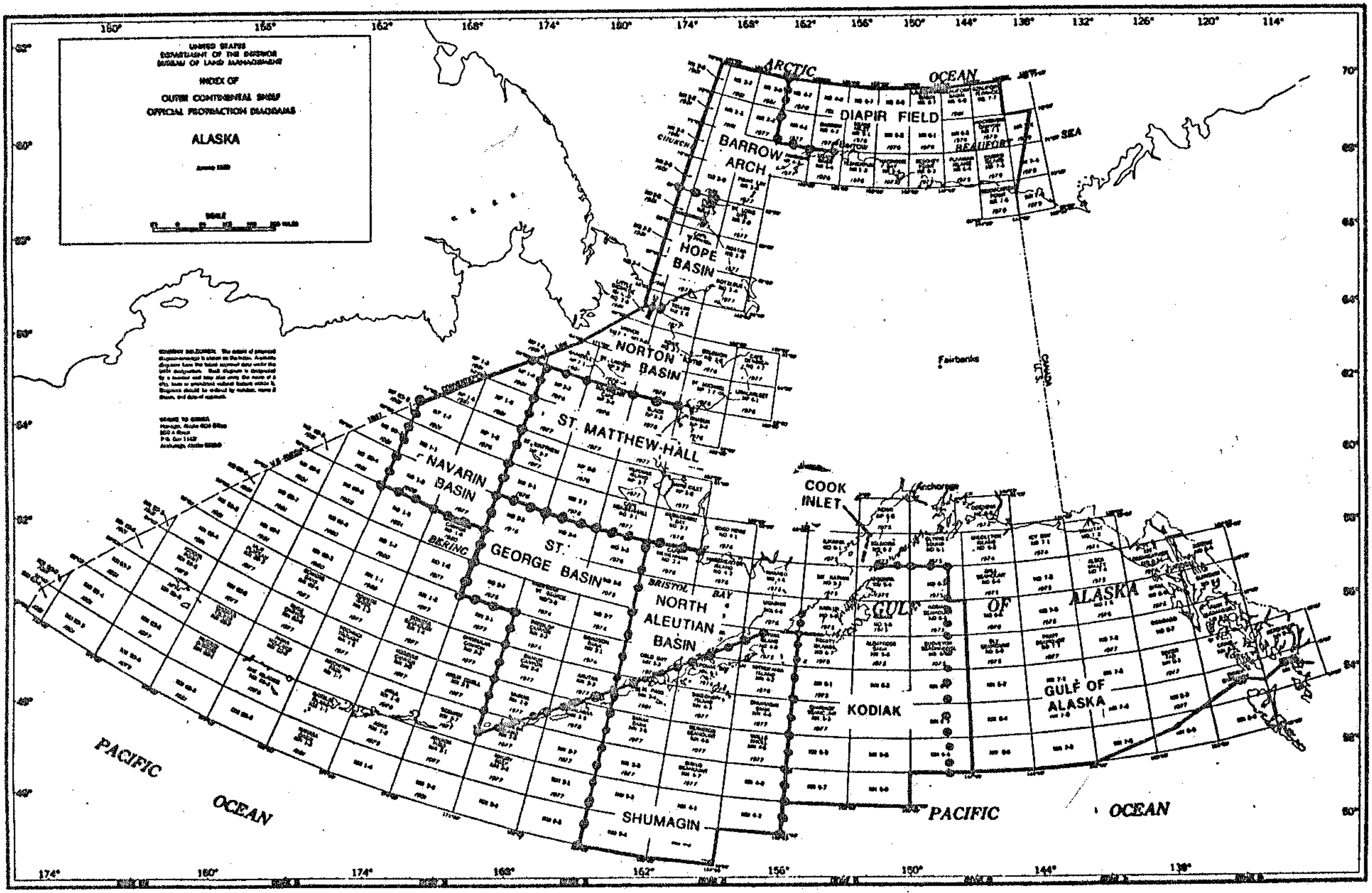
• • • • • • • • July 1981 planning area boundary

——————— proposed boundary adjustment

o—o—o—o—o—o boundary unchanged from July boundary

Figure 4

Alaska Planning Areas



July 1981 planning area boundary

proposed boundary adjustment

SECRETARIAL ISSUE DOCUMENT
for
TENTATIVE PROPOSED FINAL 5-YEAR
OCS LEASING PROGRAM

U.S. Department of the Interior
Office of OCS Program Coordination
March 1, 1982

SECRETARIAL ISSUE DOCUMENT
TENTATIVE PROPOSED FINAL 5-YEAR OCS LEASING PROGRAM

Table of Contents

List of Tables and Figures

Page

Appendices

1. Laws, Goals and Policies of Affected States
2. The 5-Year OCS Leasing Program: Economic Considerations
3. Fair Market Value
4. Availability of Transportation Networks to Bring Oil and Gas to Market
5. Interest of Potential Oil and Gas Producers
6. Summary of Comments on July Proposed Program
7. Estimated Appropriations and Staff Requirements for Tentative Proposed Final 5-Year Leasing Program
8. Estimates of External Costs
9. Discussion of Individual Planning Areas
10. Relative Environmental Sensitivity of OCS Planning Areas--Methodology

I. Introduction

This SID presents information for a decision on an OCS oil and gas leasing program as required by section 18 of the OCS Lands Act and by the D.C. Circuit Court of Appeals in their October 6, 1981, decision in California v. Watt. This SID also discusses a number of alternative leasing programs, including an example of a program based on the quantitative analysis performed pursuant to the court opinion.

Section 18 of the OCS Lands Act (OCSLA) requires the Secretary of the Interior to prepare, periodically revise and maintain an oil and gas leasing program for the U.S. Outer Continental Shelf (OCS). Section 18 requires, among other things, that "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." The Department is now engaged in a reapproval process in order to develop and put in place a new 5-year leasing program replacing the 5-year program approved in June 1980. The next step in that process, as ordered by the D.C. Circuit Court of Appeals, is submission, in mid-March, of a tentative proposed final leasing program to the Congress, the Attorney General and the Governors of affected States, and publication of it in the Federal Register.

A. Chronology of Reapproval Process

1. Annual Review

On February 13, 1981, after consideration of comments and suggestions which had been solicited in December 1980 from the governors of affected coastal States, the Attorney General in consultation with the Federal Trade Commission, the Departments of Energy and Commerce, energy firms, environmental groups and interested individuals, Secretary Watt decided that the program should be substantially changed. He concluded that the 1980 program did not meet the needs of the Nation and that a new program should be prepared. He directed that new program options be developed, placing greater emphasis on early entry into areas of high potential. He also asked that there be ways identified to streamline pre-sale preparations, accomplish necessary analytical steps more efficiently, and increase acreage offerings.

2. Draft Proposed Program

Following the February 13, 1981, directive, new program options and streamlining measures were proposed. On April 10, 1981, the Secretaries of Energy and the Interior jointly announced that the search for offshore oil was to be stepped up. They characterized the leasing plan proposed by the Interior Department as an effort of the Reagan Administration to increase the Nation's domestic energy sources and help lead America away from its heavy dependence on foreign oil imports.

On April 13, 1981, the draft proposed program was sent to the Governors of affected coastal States for comment by May 11, 1981. This comment period was later extended to May 26, 1981. The draft proposed program made the following important changes to the June 1980 program:

-- pre-sale streamlining procedures were proposed to increase the quality and quantity of lease offerings, and to shorten the period between the Call and the lease sale;

-- the number of sales was increased from 36 to 42;

-- offerings were scheduled earlier in four of five basins offshore Alaska with no previous leasing where potential is believed to be high;

-- the period between first and second sales was decreased from three years to two years in most areas; and

-- new planning area boundaries were adopted for Alaska more closely tied to geologic basins.

On April 17, 1981, the Department published in the Federal Register a request for information on the proposed streamlined leasing process. Public comments were sought on the workability and appropriateness of area-wide environmental and hydrocarbon resource assessments, tiering of NEPA documents, area-wide lease offerings, and more efficient methods for assuring receipt of fair market value. Comments were requested by May 11, 1981; this comment period was later extended to May 26, 1981.

3. Draft Supplemental Environmental Impact Statement

On June 10, 1981, the Bureau of Land Management's draft supplemental environmental impact statement (SEIS) was announced in the Federal Register. This SEIS was a supplement to the final EIS issued in January 1980 on the Proposed 5-Year OCS Oil and Gas Lease Sale Schedule. The supplement covered changes to the June 1980 schedule and the extension of the schedule to December 1986. During the week of July 21, 1981, public hearings were held in New York, Anchorage, Los Angeles, and Washington, D.C. on the draft SEIS.

4. Proposed Leasing Program

About one hundred comments were received on the draft proposed program and streamlining. These comments were summarized and provided to the Secretary, together with the draft SEIS, possible schedule options and other material related to the requirements of section 18.

On July 15, 1981, Secretary Watt announced his selection of a Proposed 5-Year OCS Oil and Gas Leasing Program and on July 24, 1981, in accordance with subsections 18(c)(3) and 18(d)(1), the proposed program was sent to the Congress, the Attorney General, and the Governors of affected coastal States. On July 31, 1981, the proposed program was published in the Federal Register. Comments were requested by October 22, 1981. Eighty-three comments were received; these are summarized in Appendix 6.

The proposed program called for 42 lease sales in the 5-year period 1982 through 1986. It included 14 offerings in the Gulf of Mexico, 16 offshore Alaska, five off California, six off the Atlantic Coast, and one reoffering sale.

Changes to the draft proposed program were made to allow for: (1) completion of a pre-sale stratigraphic testing program off Alaska; (2) operating conditions off Alaska; (3) three Gulf of Mexico sales annually after 1982 rather than two; (4) deletion of reoffering sales after 1982; (5) deletion of the St. Matthew-Hall area off Alaska in favor of a second Navarin Basin sale, also off Alaska; and (6) sale designation in the two planning areas offshore California.

Two important aspects of the program were its emphasis on leasing in high potential areas and its provision for studying the possible offering for lease of all tracts within a planning area.

The enhanced pace of leasing was made possible, in large part, by plans to streamline the pre-sale planning process developed by the BLM and USGS. Streamlining was made up of two separable components. The first was referred to as "telescoping," which is executing certain steps together instead of one at a time. Telescoping shortens the period required to prepare for a sale by about 3 months.

The second aspect of streamlining involved substantive changes in the way BLM, MMS, and USGS prepared for sales and in the composition of the sales themselves. It involved a shift in focus from studying the offering of a relatively small number of scattered tracts to studying the offering of entire planning areas. Once a planning area was included in the schedule, all but special portions of it were to be subject to the Call for Information. This new approach resulted from the following changes in the planning process:

First, a Call for Information replaced the Call for Nominations and Comments and would ask potential bidders to outline broad areas where they believe hydrocarbons may occur and where they have an interest in leasing, rather than asking for tract-specific nominations. Other interested parties, such as States and environmental organizations, would have the same opportunity to comment and identify their concerns as they have had in the past.

Second, the EIS would be prepared on the entire planning area, less any portion unavailable for oil and gas activities.

Third, the EIS prepared for the first offering in a planning area under the new concept would emphasize analysis, rather than description, and the total effects resulting from exploration and development activity that might occur within the entire planning area if all the resources in the planning area were developed. It would, therefore, provide an improved assessment of expected cumulative effects of leasing as well as an assessment of the effects believed likely to occur from the sale proposal under study.

The NEPA document prepared for the second area-wide offering in an area would update the EIS for the first offering with information that had become available since the first document was prepared. This information would include results of ongoing environmental studies and monitoring projects as well as information from any exploration activities that might take place during this period. It was expected that the second document would be shorter and take less time to prepare than the initial planning-area EIS.

Fourth, BLM's Environmental Studies Program and the USGS's regional geohazards investigations would be phased to provide a level of detail in environmental information appropriate to decisions at each step in the process. This approach recognized that the lease sale is only one of many decision and control points leading to exploration, development and production.

Fifth, pre-sale tract-specific geohazard information would no longer be gathered by the USGS to be used for tract deletion decisions. Instead, DOI would rely on the USGS regional geohazards studies in making sale decisions. The detailed tract-specific geohazard information required of lessees prior to approval of exploration and development and production plans together with the USGS regional information would be used by MMS in evaluation of both types of plans to insure that proposed operations are properly designed and safe.

Sixth, the Geological Survey's and MMS's existing and updated hydrocarbon resource estimates would be used in the EIS analysis for the broad planning areas instead of preparing new estimates for specific tracts scattered over an area as has been the past practice. This change would result in a considerable time and dollar savings to the Government. BLM would continue to use the same type of modeling techniques for EIS preparation as it had in the past. Under the old process, analytical work had to wait until after tentative tract selection and completion of GS's tract-specific estimates. However, because existing on-the-shelf hydrocarbon resource assessments would be used, analytical work could begin immediately following adoption of the leasing program.

Finally, evaluations to assure fair market value would be completed after the sale rather than before it. This would allow MMS to consider only those tracts receiving bids rather than all tracts offered for lease. While the MMS would continue to evaluate all proven, development and drainage tracts, techniques are being developed that will allow the Secretary to assure receipt of fair market value for OCS lease rights without evaluating every tract receiving a bid.

5. National Energy Policy Plan

As required by Section 801 of the Department of Energy Organization Act, the Department of Energy submitted to the Congress in July 1981 a report entitled, The National Energy Policy Plan. In reference to Federal Lands, the plan states, "The Federal role in National energy production is to bring these resources into the market place, while simultaneously protecting the environment." The proposed 5-year OCS oil and gas leasing program is an essential component of this Federal role. The fundamental purpose of the OCS program, as viewed in the context of national energy policy, is to discover, identify, and inventory those oil and gas resources that lie beneath the ocean within Federal jurisdiction, and to allow for the timely and efficient development of those resources.

6. Court of Appeals Decisions on June 1980 Program

On October 6, 1981, the D.C. Circuit Court of Appeals issued a decision involving the June 1980 5-year leasing program. It found a number of errors in the administrative record of this program.

The court remanded "the program under review and the record thereof... for revision in accordance with the [OCS Lands] Act." The court found that the June 1980 program failed to identify sales #73 and #80 with sufficient specificity. The court also found that the Secretary erred by failing to consider adequately the factors enumerated in sections 18(a)(2)(B) and (G) for the various areas of the OCS, to base the location of sales in his program on consideration of these factors, to base the timing of sales on the section 18(a)(2) factors, and to do the balancing required by section 18(a)(3). The court directed Secretary Watt to correct these failings but, in accordance with the statute, permitted the continuation of leasing.

The court found section 19 of OCSLA, and the Administrative Procedures Act, to be inapplicable to consultation procedures involved in preparation of a leasing program under section 18. It also found no violation of any trust responsibility to Inupiat Eskimos.

The court directed that there be "opportunity for public comment" once the Department has complied with the court's decision. On October 20, 1981, the Department of Justice filed a motion for clarification of this directive. On January 19, 1982, the court issued an order which, among other things, approved a schedule for compliance which had been provided to the court by the Justice Department. This schedule provided for the Department of the Interior to announce a tentative proposed final program in mid-March. This program will be transmitted to the Congress, the Attorney General and Governors of affected States and published in the Federal Register. DOI will invite comments and recommendations for a period of 30 days. In May, following consideration of any comments and recommendations received, the Secretary will announce a proposed final leasing program which will be submitted to the President and the Congress for the statutory 60-day notification period. Final action may be taken in July.

7. Secretarial Refinement of Planning Process

Two important components of the proposed program are area-wide lease offerings and the resultant area-wide environmental impact statements. On December 15, 1981, Secretary Watt refined these two concepts by making a preliminary decision to focus the environmental impact analysis on those portions of a planning area which the USGS, MMS, the oil and gas industry and others believe have potential for the production of oil and gas. Under this refinement, the planning process will work as follows:

° The 5-year program will set out entire planning areas for consideration.

° Prior to the Call for Information, GS and MMS will identify the portions of a planning area which they believe have potential for discovery of commercial deposits of oil and gas and the identified portions will be announced in the Call.

° The sale process will begin with issuance of the Call for Information. The entire planning area will be open for consideration at this point, and the Call will request information about the entire area.

° In response to the Call for Information, industry, States and other parties may suggest further areas of potential interest within or beyond those identified by GS and MMS. At the time of the Call, States and others will also have an opportunity to comment on areas or topics of concern which should be considered in the planning for the lease sale. In regard to this last point, States and others will continue to have the same opportunity to comment on environmental, ocean use, or other areas of interest or concern as they have had in the past.

° Using the responses to the Call and other available data, the Under Secretary will approve the areas of hydrocarbon potential to be proposed for leasing and analyzed in the sale-specific EIS. This approval will identify the area proposed for leasing, that is, the proposed Federal action, and will represent the Area Identification step listed on the Leasing Schedule.

° The analysis in the EIS will focus on the potential environmental effects of oil and gas activities in the area proposed for leasing. The EIS will also, as in the past, analyze alternatives to the proposed action. Finally, the EIS will include an environmental description of the entire planning area in order to provide the best available information for decisionmaking.

° The proposed Notice of Sale will include the area defined at the Area Identification step and studied in the EIS subject to appropriate consultation and consideration as called for by the National Environmental Policy Act and the OCS Lands Act.

This preliminary decision was made in order to improve planning efficiency for future sales. This refinement is intended to facilitate the important role played by the States in planning for OCS leasing, while keeping entire planning areas open for consideration and permitting the market to determine lease offerings.

8. Request for Recommendations on Fair Market Value

Assuring receipt of fair market value for leases sold is required under section 18(a)(4) of the OCSLA. On February 5, 1982, the Minerals Management Service published, in the Federal Register, a request for recommendations on procedures to be used by the Department in evaluating bids on OCS leases to assure receipt of fair market value. The request described the procedures currently used by the Department, guidelines to be reflected in the procedures adopted, and a range of options for assuring receipt of fair market value. Comments are due March 8, 1982.

B. Compliance with Section 18

Section 18 requires that the Secretary consider and base his leasing program on a number of factors. Judicial guidance as to how these requirements are to be carried out was provided by the D.C. Circuit Court of Appeals in California v. Watt. The following discussion explains how the non-procedural requirements are being addressed in the decision material being provided to the Secretary, as well as in documents which will be prepared subsequent to his decision. 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 alternatives in part III are described in terms of size, timing and location of leasing activity. All sale designations have been reviewed in order to conform with the Court guidance on the requirement that they be described "as precisely as possible" at the leasing program stage. In terms of changes to the proposed program, the locations of sales 90 and 96, previously identified as Atlantic sales have been more precisely described. Sale 90 is designated South Atlantic and sale 96 as North Atlantic, to maintain the every other year pace of sales in these planning areas. Also, the North Atlantic planning area combines two areas included in the June 1980 program--the North Atlantic and the Mid-Atlantic. This planning area was formerly divided into two areas because there is a north-south division between major shelf structures. However, interest in possible hydrocarbon-bearing structures is now turning to the Jurassic reef which extends through both areas. There are also several near-shelf basins along the reef which are almost continuous north to south. As a result of increased interest in the continuous Jurassic reef, there is much less of a rationale for separating the two areas. The combination of these two areas into a single planning area is discussed in more detail in Appendix 9. A statement on the role of the leasing program in addressing national energy needs is included in Appendix 2.

Whatever schedule the Secretary adopts as his tentative proposed final program will be appropriately described in the material transmitting it to the Congress and the Governors and will include a statement on how it addresses national energy needs.

2. 18(a)(1)

a. Requirement

"Such leasing program shall be prepared and maintained in a manner consistent with the following principles:

(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

A final supplemental environmental impact statement (SEIS) has been prepared which 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 parts II and III address the values to which this subsection of the statute refers.

3. 18(a)(2)

a. Requirement

"Such leasing program shall be prepared and maintained in a manner consistent with the following principles. . . .

(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

Item (A) regarding existing information is included in the final SEIS, as well as in summary form in Appendix 9 which discusses planning areas.

The framework for addressing Item (B), the equitable sharing consideration, is discussed under Part II.D. This discussion draws upon the analysis of the expected external costs associated with environmental damages and the expected net economic value associated with each planning area found in Parts II.A., B., and C. The analysis of expected external costs addresses potential damages from large oil spills including ecological damages, losses to tourism, recreation, commercial fishing, and clean-up costs. It also covers potential losses due to air pollution and potential losses of habitats due to onshore support activities. Potential damages for which dollar cost estimates were not made must also be considered. Qualitative descriptions of these effects are included in the FSEIS. The transmittal material used for the tentative proposed final program will explain how the 5-year program chosen by the Secretary is based, in part, on this consideration.

Item (C) which includes consideration of the location of the regions relative to regional and national energy markets and their needs, was addressed initially in an early stage of the reapproval process. In December 1980, the Department of the Interior specifically asked the Department of Energy to comment on this consideration, as well as on the availability of current and projected transportation networks. By letter dated February 2, 1981, the Deputy Assistant Secretary, Resource Development and Operations, Resource Applications, Department of Energy, advised the Director, Office of OCS Program Coordination, DOI, as follows:

> "While certain OCS leasing areas (such as the Gulf of Mexico, Southern California, and the Beaufort Sea) do possess a relative advantage due to the degree of access to onshore infrastructure and transportation networks, it is DOE's belief that the location of supply regions and the lack of existing transportation facilities should not be viewed as constraints to the OCS leasing process. As we have seen in the past, once a significant discovery is made in a frontier area, onshore facilities and transportation networks are designed to adequately meet the requirements for expeditious production of the discovery."

By letter also dated February 2, 1981, the Acting Assistant Secretary, Policy and Evaluation, Department of Energy, advised the Deputy Assistant Secretary, Policy, Budget and Administration, DOI, as follows:

> "Neither the availability of technology nor the availability of transportation should be the reason for deferring leasing. The investment in new technology is dependent on acreage becoming available. Likewise, only with proven reserves can expenditures for new transportation facilities be made. One can also safely assume that industry will not spend the money to acquire leases and to explore without some clear notion of the technology to be employed and the transportation necessary to bring supplies to market."

Further analysis on national energy considerations may be found in Appendix 2. An analysis of availability of transportation to bring resources from various OCS areas to regional and national energy markets may be found in Appendix 4.

Item (D), concerning the location of planning areas with respect to other uses, is covered in the SEIS, as well as in Appendix 9, which describes these other uses by planning area. Where possible conflicts exist, mitigation is also discussed. The estimates of the external costs developed for each area and each alternative include the costs of the potential effects of OCS oil and gas activities on other uses of the sea and seabed, particularly commercial fishing and recreation. The Secretary will need to consider whether any of these other uses, taking into account possible mitigation, pose any irresolvable conflicts which would justify deleting an entire planning area from the program.

Item (E), concerning the interest of potential oil and gas producers, is addressed in Appendix 5. 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 frequently differs from the relative ranking of areas based on USGS hydrocarbon estimates. This is important because it establishes a different basis for selecting the timing and location of sales on factors in addition to USGS and other DOI analyses.

Information regarding Item (F), laws, goals and policies of affected States can be found in Appendix 1. This information has been reviewed to determine whether any identified laws, goals or policies would make inappropriate or preclude the initiation or continuation of planning for any of the proposed sales. Two States identified laws, goals or policies which raise issues specifically related to the 5-Year Program. California identified a State policy that OCS development should occur only where the resources are sufficient to justify pipeline transportation. The Department is also concerned about the safe transportation of offshore production and has a longstanding policy of requiring pipelines (1) if pipeline rights-of-way can be obtained, (2) if pipelines are technically feasible and environmentally preferable, and (3) if, in the opinion of the lessor, pipelines can be laid without net social loss, taking into account any incremental costs of pipelines over alternative methods and any incremental benefits in the form of increased environmental protection or reduced multiple use conflicts. There is, however, no Federal legislative or policy basis for limiting, in selected areas off California, the transportation of OCS production to pipelines. The net social value calculations discussed in part II of the SID and Appendix 2 take into consideration the likely method of transport of offshore production and its expected environmental costs. For all areas, the net social value is positive. There is thus no basis for deleting entire planning areas from the schedule because hydrocarbons, if they are produced, might not be transported by pipeline. Better informed decisions can be made when more information is available about, for example, the location and quantity of production and the location of onshore handling facilities.

Alaska identified State policies that call for leasing first in areas: (1) adjacent to producing oil fields; (2) of "low physical hazard rating;" and (3) of lowest biological productivity, vulnerability and diversity and of least commercial, subsistence and recreation use. Consideration of the second and third points is part of the section 18 analysis. The first policy is inconsistent with the Federal goal of inventorying the oil and gas resources of the OCS. Issues raised by other State policies identified by Alaska, such as consideration of effect of OCS activities on fish and wildlife resources, are addressed in the Final SEIS and/or this document.

Alaska also recommends that sales be delayed to allow for completion of local coastal management plans. We have advised Alaska in the past that our willingness to proceed with planning activities in the areas they identified is based on lead times available to the Department for study and consultation before exploration, and later development and production are allowed to proceed. The long lead times anticipated for the start of production should allow for completion of coastal zone management plans prior to approval of development and production plans as well as exploration plans in most areas. If local coastal zone management plans are not in place, the Department can and will make every effort to see that offshore and onshore development activities are properly planned and sensitive to local problems.

As upheld in California v. Watt, the Secretary need not delete an area from the schedule solely because such activity may be inconsistent with State policies. The information found in Appendix 1 may also be useful in assessing of potential effects on the coastal zone as required by 18(a)(3).

Item (G) regarding relative environmental sensitivity and marine productivity is addressed and summarized in Part II.B and in Appendix 10. Professional judgments have been made of the relative environmental sensitivity and marine productivity of each OCS area and the adjacent coastal areas. These judgments were based on a detailed review of data on the environmental and marine resources in each area. This analysis provides a partial basis for considering "an equitable sharing of developmental benefits and environmental risks" 18(a)(2)(B) and the balancing of factors called for by 18(a)(3).

Estimates of external costs found in Part II.C. and Appendix 8 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 sensitivity and productivity should therefore be reviewed together with the external cost rankings.

Item (H), environmental and predictive information, has been addressed in the SEIS, both in a descriptive and analytical manner, as well as in Appendix 9. Such information has also been used in developing the environmental sensitivity and marine productivity matrices and the balancing analysis, found in Part II.B and E.

In reviewing the June 1980 program, the Court found that the Secretary failed to consider items (B) and (G) in determining the location of leasing. These items, together with the other 18(a)(2) items, have been reviewed to determine if any planning areas warrant exclusion from the schedule. Consideration of the location question can be found in Part III.B.1.

In determining the timing of leasing, the court found that the Secretary failed to incorporate the environmental and coastal zone considerations of section 18, or at least failed to explain how this consideration occurred. The discussion of leasing programs in Part III includes an analysis of the five schedules in the Final SEIS using quantitative estimates reflecting the factors which section 18 requires to be considered. In addition, an entirely new schedule based on this quantitative analysis is presented. A detailed treatment of how these factors were considered and are reflected in the tentative proposed final program chosen by the Secretary will accompany the program when it is transmitted to the Governors and the Congress in mid-March.

4. 18(a)(3)

a. Requirement

"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."

b. Compliance

This requirement is initially addressed in Part II.E. which presents information on external costs including environmental damage and adverse effects on the coastal zone, expected oil and gas resources, and net economic values by planning area. This information is used to calculate the net social value of each area. The net social values are also estimated for alternative leasing programs found in Part III.C.

Relevant factors not reflected in these calculations are assessed in the FSEIS, Parts II.B. and C. and Appendices 1, 5, 6, 8 and 10. These factors are being reviewed together with the net social value calculations in formulating a leasing program.

The court endorsed the general interpretation of the balancing required by 18(a)(3) which was used in formulating the June 1980 program. This interpretation was that an area should be included if the benefits of leasing exceed the costs and that the most valuable areas should be offered first. The court, however, ruled that the failure to consider explicitly all aspects of section 18(a)(2) precluded compliance with 18(a)(3). It also found that the analysis of both 18(a)(2) and 18(a)(3) factors also needs to be on an area-by-area basis, not only on a schedule-by-schedule basis.

The court also required that the damage from oil spills on fishing, tourism and other OCS related enterprises be quantified. This has been done in the calculation of external costs for each area and is described in Part II.C. and Appendix 8. The court also asked that the calculation of net economic value be explained. This is done in Appendix 2.

5. 18(a)(4)

a. Requirement

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

b. Compliance

Proposed changes in tract evaluation procedures for assuring receipt of fair market value are being analyzed in a parallel decision package. Decisions on the leasing schedule are, for the most part, separable from decisions on tract evaluation procedures. However, the decision will be made on tract evaluation procedures contemporaneously with other decisions on the program so that means for assuring receipt of fair market value are published for review as part of the tentative proposed final leasing program. A paper discussing the conceptual underpinnings of this requirement and of the general approaches considered in meeting it can be found as Appendix 3. On February 5, 1982, a request for recommendation on procedures to be used by DOI in evaluating bidding to assure receipt of fair market value was published in the <u>Federal Register</u>. Comments are due March 8, 1982. These comments will be analyzed in a separate SID on assuring fair market value which is being prepared by the Minerals Management Service. The material transmitting the program to the Governors and the Congress will explain how any new procedures meet the statutory requirement.

6. 18(b)

a. Requirement

"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;

(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

Appendix 7 includes estimates of appropriations and staff for all alternative programs. Summaries of these estimates appear in Part III. Once a program is adopted, any necessary adjustments will be made and will be reflected in the material transmitted to the Governors and the Congress.

II. Comparative Analysis of Planning Areas

Section 18(a)(2) of the OCS Lands Act requires that the Secretary engage in a comparative analysis of the various "oil-and gas-bearing physiographic regions of the OCS" in determining the timing and location of leasing. Such a comparative analysis has been performed which identifies for each OCS planning area: (1) the estimated hydrocarbon resources; (2) their net economic value (the market value of expected production less the direct costs of production and transportation to market); (3) external costs (measurable social and environmental costs) which might result from offshore oil and gas activities, taking into account the relative environmental sensitivity and marine productivity of each area; and (4) expected net social value (net economic value less external costs).

The comparative analysis ranks the 18 OCS planning areas by each of the measures mentioned in the first paragraph of this section. Maps of the planning areas are in Part IV. Relevant information is also provided on the division of the North Atlantic area into two separate areas (North Atlantic and Mid-Atlantic), and for St. Matthew-Hall Basin. (Prior to adoption of the proposed program in July, 1981, the Mid and North Atlantic areas were separate planning areas. In order to analyze leasing alternatives developed prior to that date, it was necessary to include an analysis of both areas. The July proposal also includes two transition sales, sale 52 - North Atlantic and sale 76 - Mid-Atlantic. St. Matthew-Hall Basin was included in the draft proposed program issued in April, 1981.)

A factor which may bear upon these considerations, but is not apparent from the tables that follow, concerns the proper contribution of Alaskan sales to a balanced OCS program. While Alaskan OCS planning areas may appear to make up a disproportionate share of the sales (38% in the July proposal), the size of the Alaskan OCS and its share of the resources are extremely high. Planning areas off Alaska contain 57 percent of the total planning area acreage included in the July 1981 proposal. The Alaskan OCS is estimated to contain 30 percent of the remaining OCS hydrocarbon resources. In addition, the Alaska coastline is one-third greater than the coastline of the entire contiguous 48 States.

This comparative analysis has been done in order to allow the Secretary to address the following three requirements of section 18:

- that the timing and location of leasing be based on a consideration of "an equitable sharing of developmental benefits and environmental risks among the various regions" (§18(a)(2)(B);

- that the timing and location of leasing be based on a consideration of "the relative environmental sensitivity and marine productivity of different areas of the outer Continental Shelf." (§18(a)(2)(G)); and

- that he "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" (§18(a)(3)).

This comparative analysis is subject to considerable uncertainty. Net economic value is uncertain because outside the Central and Western Gulf of Mexico, the inventorying of resources through drilling has either not started or has just barely begun and because costs are uncertain in frontier areas due to a lack of experience there. External costs are uncertain because there is no commonly accepted method for assigning economic values to non-market goods and because certain intrinsic values cannot be assigned dollar values. Expected external costs and net social value are conservative for reasons discussed near the end of Part II.C. The estimates of net social value are also conservative because the rate of large oil spills ($\geq$ 1,000 barrels) used in the calculations does not reflect the experience of the past decade when there have been only two platform spills of over 1,000 barrels. Nevertheless, the difference between estimated net economic value and estimated external costs, which is expected net social value, is so large that in every planning area the external costs would have to be many times larger than estimated in order to reduce the expected net social value to zero. In one instance, the expected net social value is about 20 times larger than the estimated external costs. In every other case, the difference is larger.

A. Hydrocarbon Resources and Net Economic Value

1. Hydrocarbon Resources

Table 1 presents the ranking of OCS planning areas by USGS estimates of expected hydrocarbon resources. Expected resources are those quantities of oil and gas which are expected to be present, taking into account both the probability that hydrocarbons are present in the area and the mean estimates of the volumes of oil and gas which could be contained in the area. Quantities of gas have been converted to oil equivalence. A more detailed explanation of these numbers can be found in Appendix 2.

Table 1 shows that the Central Gulf of Mexico has the highest estimated expected resources, followed by the North Atlantic, Western Gulf of Mexico, and Diapir Field. Differences between consecutive areas in this group vary from 10% to 30%. Southern California and Navarin Basin are next containing less than half the amount of expected resources of Diapir Field. These two areas lead a second group (5th through 11th) in which differences are about 10% to 25%. At 12th and 13th are the Gulf of Alaska and Kodiak at the same level followed by Norton Basin and North Aleutian Basin at 14th and 15th, but with nearly 50% less resources. Shumagin and Cook Inlet are another 50% lower and Hope Basin, the least promising area, is another 50% less. The variation from top to bottom is nearly 100 fold.

Table 1. OCS Planning Areas Ranked by Estimates of Expected Hydrocarbon Resources

		Billions of Barrels of Oil Equivalent
1.	Central Gulf of Mexico	9.5
2.	North Atlantic	7.0
3.	Western Gulf of Mexico	6.1
4.	Diapir Field	5.4
5.	Southern California	2.3
6.	Navarin Basin	1.9
7.	South Atlantic	1.6
8.	Barrow Arch	1.3
9.	Eastern Gulf of Mexico	1.2
10.	Central and Northern California	1.2
11.	St. George Basin	0.9
12.	Gulf of Alaska	0.7
13.	Kodiak	0.7
14.	Norton Basin	0.4
15.	North Aleutian Basin	0.4
16.	Shumagin	0.2
17.	Cook Inlet	0.2
18.	Hope Basin	0.1
	(Old North Atlantic)	(2.3)
	(Old Mid-Atlantic)	(4.7)
	(St. Matthew-Hall)	(0)

2. Net Economic Value

Table 2 shows planning areas ranked by net economic value per barrel of oil equivalent. Table 3 shows planning areas ranked by the expected net economic value of total production.

Net economic value per barrel is the expected average difference between the product price and the costs of exploration, development production, and transportation. Estimates were made assuming that the resources were leased in 1982 and that exploration, development and production and transportation would occur at the times typical for each area. These estimates are the best measure available of the extent of the contribution of OCS development to future income to be generated in the U.S. economy. The expected resources (in barrels of oil equivalent) in each basin were multiplied by the estimated net economic value per barrel to arrive at the net economic value of resources in each basin.

The comparison provided by the net economic value rankings allows the Secretary to consider the way in which the potential discoveries of oil and gas in each area will help meet the nation's energy and economic needs. The importance of the OCS leasing program to the U.S. economy can be judged from the fact that the net economic values total nearly one half of a trillion dollars. A detailed explanation of these estimates may be found in Appendix 2.

It is important to note that even though the estimated planning area economic values have a considerable range (the largest is 160 times the smallest), the per barrel values are all substantial and the range is much narrower (the largest is double the smallest). This means that even though areas with low ranking on Table 3 are not expected to contribute as much value as the areas with high ranking, the oil and gas resources they do produce are nevertheless expected to be of substantial value on a per barrel basis.

It is also important to note that the planning area net economic values are based on an average for all resources expected to be produced. In an actual situation, one would expect that the early production in an area would yield values higher than the average. Thus, the net economic values would likely be higher than shown if it were possible to analyze this effect.

The ranking of areas by expected net economic value of total production (Table 3) does not differ very significantly from the ranking by expected resources (Table 1). Differences from area to area are somewhat greater, however, because of the variation added by differences in average costs from area to area. Most important, the areas in the Gulf of Mexico are ranked higher compared to other areas because of the lower costs and higher average net economic value. In general, the clusters of areas remain about the same with some change in ranking within the clusters. Western Gulf of Mexico moves up above the North Atlantic in the first group while the Eastern Gulf moves above South Atlantic and Barrow Arch in the second group. The ranking of the 11th through 18th areas is essentially the same for total production and net economic value.

Table 2. OCS Planning Areas Ranked by Net Economic Benefit per Barrel

		Net Economic Benefit ($ per barrel of oil equivalent)
1.	Southern California	$15.40
2.	Central Gulf of Mexico	13.50
3.	Western Gulf of Mexico	13.50
4.	Eastern Gulf of Mexico	13.50
5.	Central and Northern California	13.50
6.	Cook Inlet	10.60
7.	Gulf of Alaska	10.60
8.	Shumagin	10.60
9.	Kodiak	10.60
10.	North Atlantic	9.60
11.	South Atlantic	9.60
12.	Navarin Basin	9.15
13.	St. George Basin	9.15
14.	Diapir Field	8.70
15.	North Aleutian Basin	8.70
16.	Barrow Arch	8.20
17.	Hope Basin	7.25
18.	Norton Basin	7.25
	(Old North Atlantic)	(10.80)
	(Old Mid-Atlantic)	(10.80)
	(St. Matthew-Hall)	(0)

Table 3. OCS Planning Areas Ranked by Expected Net Economic Value of Development of Expected Recoverable Resources ($ billions)

		Net Economic Value
1.	Central Gulf of Mexico	128
2.	Western Gulf of Mexico	82
3.	North Atlantic	67
4.	Diapir Field	47
5.	Southern California	36
6.	Navarin Basin	18
7.	Eastern Gulf of Mexico	17
8.	South Atlantic	15
9.	Central and Northern California	14
10.	Barrow Arch	11
11.	St. George Basin	8
12.	Gulf of Alaska	7
13.	Kodiak	7
14.	North Aleutian Basin	3
15.	Norton Basin	3
16.	Cook Inlet	2
17.	Shumagin	2
18.	Hope Basin	0.8
	(Old North Atlantic)	(20)
	(Old Mid-Atlantic)	(45)
	(St. Matthew Hall)	(0)

The net economic value estimates in Table 3 need to be considered in light of the possibility that some or all of the recoverable gas discovered in Alaskan provinces may not be produced because of transportation costs. The estimates shown in Tables 2 and 3 assume for all regions that recoverable resources of gas will be produced and delivered to market. However, decisions on development of oil and gas fields in Alaska are very sensitive to costs, particularly the transportation costs. Transportation of gas from Alaskan basins is generally more costly than an equivalent quantity of oil. Given the high cost of production in these remote Alaskan regions, the difference in transportation costs between oil and gas may well result in a considerable amount of discovered gas going unproduced for a significant period of time.

A 1981 study by the National Petroleum Council (NPC) found that of 68 trillion cubic feet (TCF) of potentially recoverable non-associated gas, only 10 TCF are economical to produce and transport to market assuming industry requires a 10% rate of return (at 15% none would be economical). This estimate is based on the assumed price of $6.50 per thousand cubic feet, which is somewhat higher than the current price of gas would be if it were deregulated. However, an analysis by DOE indicates that a real $6.50 price may be obtained by the late 1980's under deregulation. Without deregulation the gas could be produced today and "rolled in" with lower price gas.

On the other hand, a study by the Energy Productivity Center of the Mellon Institute has forecast that gas prices may be as much at 40% less than oil prices. To the extent that deregulated gas prices lag behind those of oil prices, less gas production can be expected from remote Alaskan OCS planning areas. Thus, under deregulation, the NPC estimate of the extent of Alaskan gas production may be an overstatement. Without deregulation, however, the gas could be produced and transported at higher cost and "rolled in" with lower price gas. This would result in more Alaskan gas being produced.

From another perspective, the NPC's estimates are somewhat conservative since they assume that "grass roots" transportation systems will be required for each basin. They ignore the possibility that some gas from the Diapir Field or the Barrow Arch may be transported through the ANGTS pipeline system. The NPC study found that only gas from the Navarin, St. George, Norton, and North Aleutian basins might be recoverable. The probabilities of finding the minimum economic reserve size for each basin are 18%, 16%, 7% and 14%, respectively. If the ANGTS pipeline is built, however, it is likely that gas production from the Diapir Field will occur if pipeline capacity is available. This would add 4.1 TCF of non-associated gas production according to the NPC or 14.75 TCF of associated and non-associated gas production according to USGS.

The NPC study is also somewhat conservative in considering only non-associated gas for development. The study assumed that all associated gas would be reinjected to maintain reservoir pressure or burned on-site for fuel.

Table 4 shows the effect of excluding gas from the estimates of net economic value of development of the expected resources in all Alaskan basins except the Diapir Field.

Table 4. OCS Planning Areas Ranked by Expected Net Economic Value of Total Production, Excluding Alaskan Gas Production*
($ Billion)

		Net Economic Value
1.	Central Gulf of Mexico	128
2.	Western Gulf of Mexico	82
3.	North Atlantic	67
4.	Diapir Field *	47
5.	Southern California	36
6.	Eastern Gulf of Mexico	16
7.	South Atlantic	15
8.	Central and Northern California	14
9.	Navarin Basin	9
10.	Barrow Arch	6
11.	St. George Basin	5
12.	Gulf of Alaska	4
13.	Kodiak	4
14.	North Aleutian Basin	2
15.	Norton Basin	2
16.	Cook Inlet	1
17.	Shumagin	1
18.	Hope Basin	.02

* It is assumed that the Alaskan Natural Gas Transportation System will be built and gas from the Diapir Field will be produced.

B. Relative Environmental Sensitivity and Marine Productivity

1. Relative Environmental Sensitivity of OCS Planning Areas

Section 18(a)(2)(G) requires that the timing and location of oil and gas activities among oil and gas bearing physiographic regions be based upon a consideration of relative environmental sensitivity. The Department has interpreted this to mean the sensitivity of the environment to oil and gas activities.

A number of factors could be considered in ranking the environmental sensitivity of the OCS planning areas. These include resources, such as coastal habitats, (i.e., wetlands and beaches); discrete marine habitats (i.e., submarine canyons and reefs); endangered species and their habitat; marine mammals and their habitat; birds and their habitat; fisheries resources, including nursery grounds and spawning as well as adults; and air and water quality. The sensitivity of those resources to various aspects of OCS development, such as oil spills, structure placement, discharges and air emissions could also be considered.

It was, however, decided to base relative environmental sensitivity rankings on the sensitivity of various coastal and marine habitats to oil spills. This method was chosen for several reasons.

First, examining sensitivity by habitat type allows all OCS areas to be analyzed according to common factors, avoiding the difficulty of weighting and comparing very different resources in different planning areas. Second, considering specific resources such as fish and endangered species, along with the coastal and marine habitat types would result in overlap--for example, wetlands often act as nursery grounds. Also, consideration of habitat sensitivity was confined to the sensitivity to oil spills because spill effects are considered by many experts to be the greatest measurable biological effect of OCS development. Furthermore, some non-spill effects are localized and highly dependent on site-specific factors, and therefore have limited value for comparing entire planning areas. Finally, sensitivity to some environmental effects of OCS development is almost impossible to evaluate without considering the expected level of OCS activities--i.e., it is difficult to establish a concensus definition of sensitivity. As a result of these considerations, sensitivity of major habitats to oil spill damage was singled out for ranking the sensitivity of OCS planning areas.

Despite the fact that all environmental aspects of OCS development are not explicitly factored into the sensitivity ranking, all the resources and factors mentioned above have been considered in the environmental assessment and/or in other analyses developed to provide the Secretary with information to achieve the required balancing of factors listed in Section 18. In particular, the Final Supplemental Environmental Impact Statement (SEIS) evaluates the potential for site-specific and planning-area impacts, based both on sensitivity of the resources to impacts and upon the likelihood of impact. The SEIS includes measurable as well as unquantifiable effects of alternative OCS oil and gas programs. The external cost analysis also includes analysis of these possible environmental risks, considering resource sensitivity, probability of effects and value of resources.

For ranking purposes, coastal habitats were divided into the following types: beaches (including barrier islands), wetlands (including marshes and tundra), rocky shores (including cliffs), and lagoons (Alaska only). Marine habitats were divided into aquatic beds, submarine canyons, reefs and hard bottoms.

The criteria used for determining sensitivity to oil spills were: persistence of oil within the habitat, time for structural recovery of the habitat from oiling, and the degree of damage which would result from attempted clean-up. Each habitat was ranked for sensitivity according to these criteria, and the results weighted using abundance of each habitat within the planning area as the weighting factor.

As a result of this methodology, planning areas with a large proportion of particularly sensitive habitat (such as wetlands) that might be exposed to oil spills, should they occur, would tend to be rated higher in sensitivity than planning areas with a large proportion of less sensitive habitat (such as beaches). Furthermore, while all wetlands are relatively high in sensitivity to spills compared to beaches, (due in part to relative energy levels), wetlands in some areas are more sensitive than wetlands in other areas, largely due to temperature (which affects recovery time). Thus, colder areas with sensitive habitats would tend to be ranked higher than warmer areas with an equal proportion of sensitive habitats.

Application of these criteria involved considerable judgement. The resulting ratings represent the best judgement of Department of the Interior scientists. Using the methodology discussed above, planning areas are ranked as follows for relative environmental sensitivity:

Highest	Next to Highest	Next to Lowest	Lowest
Shumagin	Kodiak	C. Gulf of Mexico	E. Gulf of Mexico
Norton Basin	No. Aleutian Basin	So. California	Barrow Arch
Gulf of Alaska	Diapir Field	So. Atlantic	W. Gulf of Mexico
St. George Basin	C & N California	No. Atlantic (7/81)	No. Atlantic (6/80)
Cook Inlet		Mid-Atlantic (6/80)	Hope Basin
St. Matthew-Hall			Navarin Basin

Appendix 10 includes tables showing how each habitat within each planning area was ranked, and the specific methodology used to calculate relative sensitivities. An example calculation of relative sensitivity of a planning area is also included in the Appendix.

In addition to the rankings above, information on the relative sensitivities of some other resources of concern, by planning area, is provided in Table 5. A summary of the high rankings included in this table appears in Appendix 10.

The rankings of relative environmental sensitivity should not be construed as indicating the level of effects expected as a result of OCS development. Many factors are not considered in the relative sensitivity analysis which would be required to determine the level of effects to a planning area from OCS sales, including the projected amount of hydrocarbon resources, their location within the planning area, the number and trajectory of likely oil spills and the location of possible spill sites, and other factors. An assessment of estimated levels of environmental effects of alternative leasing schedules may be found in the Final Supplemental Environmental Impact Statement (FSEIS).

In summary, the areas of the highest sensitivity include all Alaskan areas except Navarin Basin, Hope Basin and Barrow Arch, and include as well, Central and Northern California. Of these, Shumagin, Norton Basin, Gulf of Alaska, St. George Basin and Cook Inlet were ranked highest. With the exception of the Gulf of Alaska and Shumagin, all of these areas were also ranked as relatively highly sensitive to effects on endangered species; all showed high relative sensitivities for coastal and/or pelagic birds; and Central and Northern California, Gulf of Alaska, Shumagin and North Aleutian Basin all were ranked as relatively highly sensitive for effects on marine mammals. Only Central and Northern California, of this group, was ranked relatively highly sensitive to effects on commercial fisheries resources.

The next lowest group in overall sensitivity includes the Mid- and South Atlantic, Central Gulf of Mexico and Southern California. All of these areas were also ranked as relatively highly sensitive for endangered species and, except for the Mid-Atlantic, for commercial fisheries resources. Southern California was also ranked as relatively highly sensitive for marine mammals and coastal and pelagic birds.

Finally, the Eastern and Western Gulf of Mexico, North Atlantic (June 1980) and the three Alaskan areas not included in the highest category (Hope and Navarin Basins, Barrow Arch) make up the group lowest in relative overall environmental sensitivity. However, this group, though ranked lowest, also possesses resources ranked relatively high in sensitivity to OCS development. All except the North Atlantic were ranked high for endangered species; the Gulf of Mexico areas and the North Atlantic were rated high for commercial fisheries resources, and Navarin and Hope Basins and the North Atlantic high for birds (Atlantic and Navarin Basin for pelagic birds only).

Table 5 Relative Sensitivity of Marine Resources to OCS Development by Planning Area

	North Atlantic (June 1980)	Mid-Atlantic (June 1980)	North Atlantic (proposed July 1981)	South Atlantic	Eastern Gulf of Mexico	Central Gulf of Mexico	Western Gulf of Mexico	Southern California
Endangered Species Oil Spills	M	H	H	H	H	H	H	H
Habitat	M	M	M	M	M	M	M	M
Vessel Contact	L	L	L	L	L/	L	L	M
Coastal Birds Oil Spills	M	M	M	M	M	M	M	H
Habitat	M	M	M	M	M	M	M	H
Pelagic Birds Oil Spills	H	M	H	M	M	M	M	H
Habitat	H	M	H	M	M	M	M	H
Marine Mammals Oil Spills	M	M	M	M	M	M	M	M
Habitat	M	M	M	M	M	M	M	H
Vessel Contact	L	L	L	L	L	L	L	L
Pelagic Commercial Fish and Shellfish Spawning and Larvae*	H	M	H	H	H	H	M	M
Coastal Commercial Fish and Shellfish Spawning and Larvae*	L	L	L	H	H	H	M	M
[illegible] Fish and Shellfish in Nursery Ground*	H	M	H	H	H	H	H	M
[illegible]ercial Fish and [illegible]ellfish*	H	M	H	H	H	H	H	H
Pelagic Subsistence Fish and Shellfish Spawning and Larvae*	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Coastal Subsistence Fish and Shellfish Spawning and Larvae*	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Subsistence Fish and Shellfish in Nursery Grounds*	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Adult Subsistence Fish and Shellfish*	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table 5 Relative Sensitivity of Marine Resources to OCS Development by Planning Area

	Central and Northern California	Gulf of Alaska	Kodiak	Cook Inlet	Shumagin	North Aleutian Basin	St. George Basin	St. Matthew-Hall Basin
Endangered Species Oil Spills	H	M	M	M	M	H	H	M
Habitat	M	L	M	L	M	M	L	M
Vessel Contact	L	L	L	L	L	M	L	L
Coastal Birds Oil Spills	H	M	M	H	M	H	H	H
Habitat	H	M	M	H	M	H	H	H
Pelagic Birds Oil Spills	H	M	H	H	H	H	H	H
Habitat	H	M	H	H	H	H	H	H
Marine Mammals Oil Spills	M	H	H	H	H	H	H	M
Habitat	H	H	H	H	H	H	H	M
Vessel Contact	L	L	L	L	L	L	L	L
Pelagic Commercial Fish and Shellfish Spawning and Larvae*	H	L	L	L	L	M	L	L
Coastal Commercial Fish and Shellfish Spawning and Larvae*	H	M	M	M	M	M	M	M
Commercial Fish and Shellfish in Nursery Grounds*	H	L	M	M	M	M	M	M
[illegible]dult Commercial Fish and S[illegible]llfish*	H	L	L	L	L	M	M	M
[illegible] Fish and [illegible] and Larvae*	N/A	L	L	M	L	L	L	L
[illegible] [illegible]pawning and Larvae*	N/A	M	M	M	L	L	M	M
[illegible] Fish and Shellfish in Nursery Grounds*	N/A	L	L	L	L	L	L	L
Adult Subsistence Fish and								

Table 5 Relative Sensitivity of Marine Resources to OCS Development by Planning Area

	Navarin Basin	Norton Basin	Hope Basin	Barrow Arch	Diapir Field
Endangered Species Oil Spills	M	H	H	H	H
Habitat	M	M	L	L	L
Vessel Contact	L	L	L	M	M
Coastal Birds Oil Spills	L	H	M	M	H
Habitat	L	H	H	M	H
Pelagic Birds Oil Spills	H	H	H	M	M
Habitat	H	H	H	M	M
Marine Mammals Oil Spills	M	M	M	M	M
Habitat	M	M	M	M	M
Vessel Contact	L	L	L	L	L
Pelagic Commercial Fish and Shellfish Spawning and Larvae*	L	L	L	L	L
Coastal Commercial Fish and Shellfish Spawning and Larvae*	L	H	L	L	L
Commercial Fish and Shellfish in Nursery Grounds*	L	M	L	L	L
Adult Commercial Fish and Shellfish*	L	M	L	L	L
Pelagic Subsistence Fish and Shellfish Spawning and Larvae*	--	L	L	L	L
Coastal Subsistence Fish and Shellfish Spawning and Larvae*	--	M	L	L	M
Subsistence Fish and Shellfish in Nursery Grounds*	--	M	L	L	L
Adult Subsistence Fish and Shellfish*	--	L	L	L	L

Most of the planning areas falling within the highest relative environmental sensitivity categories, as ranked by habitat sensitivities, also showed high relative sensitivities to many other marine resources. To a great extent, this is a reflection of the great number of breeding birds and mammals and migratory bird staging and feeding areas in southern Alaska and the Bering Sea, as well as the coastal wetlands and lagoons in a climate where physical disruption or destruction of the ecosystem would result in long recovery times.

However, even those areas ranked at the lower end of the spectrum for relative sensitivity to OCS activities possess sensitive resources which will require careful assessment of possible effects at the sale stage and evaluation to determine the necessity of special protective measures. For example, the Western Gulf of Mexico includes the Flower Garden Banks coral reefs for which special stipulations are currently in force, and there are hard bottom coral assemblages in the Central Gulf and especialy productive habitats in the submarine canyons of the North Atlantic. The North Atlantic is also one of the most highly productive marine areas outside of the Bering Sea. Hope Basin supports large populations of breeding birds and is a migratory passage way for marine mammals, including endangered whales.

As previously indicated, a relatively low overall environmental sensitivity ranking does not indicate absence of sensitive resources in a planning area. Furthermore, a high overall sensitivity ranking or the presence of many sensitive resources in a planning area does not necessarily imply a relatively high level of adverse effects from OCS development. Relative environmental sensitivity ratings must be evaluated along with other environmental considerations--both quantified and non-quantifiable--(including the SEIS impact assessment) in order to balance the environmental risks with other factors in determining the size, timing, and location of OCS sales.

2. Relative Marine Productivity of OCS Planning Areas

Introduction

Section 18(a)(2)(G) requires that the Secretary consider the relative marine productivity of different areas of the Outer Continental Shelf. Following is information on relative productivity of the different planning areas and a discussion of the significance of this information for determining the timing and location of OCS leasing.

Primary Productivity

When biologists speak of productivity, they are often referring to primary productivity, the amount of total plant tissue produced during a time period by photosynthetic-fixation of carbon. Thus, primary productivity, measured by the amount of carbon fixed, is one measure of marine productivity for OCS planning areas.

When expressed on an annual, areal basis, values for photosynthetically-fixed carbon provide an effective means of characterizing the relative productivity of different areas of the ocean. However, annual values do not reflect seasonal variations, which are most pronounced in the more northerly areas. Additionally, much higher productivity levels are found in coastal areas, over shoals, and in regions of upwelling, which have characteristically higher nutrient levels to support higher plant production. In any given planning area, productivity will vary tremendously, especially when moving from nearshore areas to the open shelf and beyond the slope.

In most areas, primary productivity is largely determined by the extent of light penetration and the replenishment of plant nutrients in the upper layers of the water when these are depleted through plant production. Nutrients are replenished by other nutrient-rich waters mixing with the upper water layers. Thus, water mixing which brings nutrient-rich cold water (deeper layers) to the surface is very important to determining productivity. In arctic areas, the angle of the sun's rays, and thus the light availability is probably the most important limiting factor.

The more northerly U.S. waters are generally most productive, except that productivity declines in the arctic waters. The first column in Table 6 indicates the range of carbon values found in various planning areas, based on a generalized map of world-wide ocean productivity. Based on this generalization, OCS planning areas could be ranked as follows for marine productivity:

Table 6
Marine Productivity by Planning Area

Planning Area	Primary Productivity Range as shown by Smith and Kalber, 1974 1/ (grams carbon/ m^2/year)	Primary Productivity-- Reported Measures 2/ (grams carbon/ m^2/year)	Breeding Coastal Birds 2/ (thousands)	Breeding Seabirds 2/ (thousands)	Breeding Marine Mammals 2/ (thousands)	Harvested (commercial & recreational) Fish and Shellfish 3/ (thousand tons)
North Atlantic	100-400		40 (+?)	700	7(+?)	828
June 1980 N. Atl.	200-400	135	5 (+?)	300	7(+?)	321.5
June 1980 Mid-Atl.	100-200	36	70 (+?)	270	?	506.5
South Atlantic	50-200	29	1,055	200	35 (+?)	227
Eastern Gulf of Mex.	50-100	38	131	?	1.4-2(+?)	61.5
Central Gulf of Mex.	50-100	20	2,630	200	1-1.5(+?)	802.5
Western Gulf of Mex.	50-100	65	2,620	?	1-1.5(+?)	51
Southern California	200-400	143	2	>40	>100	314.5
Cen. & N. Calif.	200-400	128	3	600	>16	59 .5

Table 6 (continued)

Gulf of Alaska	200-400	>100	3,200	>35	336
Kodiak	200-400	>75	3,200	>85	47
Shumigan	200-400	?	7,000	>25	with N. Aleut. Basin
Cook Inlet	200-400	very high numbers	>500	>40	7
N. Aleutian Basin	400-7300	very high numbers	3,000	many	149
St. George Basin	400-7300	1,650	8,800	>2,500	with N. Aleut. Basin
St. Matthew-Hall Basin	200-400	high numbers	3,600	many	?
Navarin Basin	50-200	-	?	many	?
Norton Basin	50-100	sev. mill.	3,500	several	2
Hope Basin	< 50	high numbers	>880	several	< .5
Barrow Arch	< 50	high numbers	>312	mod.-high numbers	?
Diapir Field	< 50	high numbers	>4,000	mod. numbers	?
(State of Alaska)					470.5

1/ Taken from map in Handbook of Marine Science, Volume II, by F. G. Walton Smith and F. A. Kalber, 1974.
2/ Numbers reported by BLM OCS offices, from numerous sources.
3/ These figures do not represent the abundance of fisheries resources, only what has been harvested domestically. All data from U.S. Department of Commerce (NOAA/NMFS) Fisheries of the United States, 1980 (Current Fisheries Statistics No. 8100), except data for planning areas in Alaska. These data were compiled from many sources and different years by the OCS Office. Some figures represent averages of several years catch. Because of the difference in sources, these planning area figures exceed the total for the State of Alaska reported by

Highest	Next to Highest	Next to Lowest	Lowest
No. Aleutian Basin	North Atlantic	South Atlantic	Hope Basin
St. George Basin	Southern Calif.	Navarin Basin	Barrow Arch
	C & No. Calif.	E. Gulf of Mexico	Diapir Field
	Gulf of Alaska	C. Gulf of Mexico	
	Kodiak	W. Gulf of Mexico	
	Shumigan	Norton Basin	
	Cook Inlet		
	St. Matthew-Hall		

The second column in Table 6 includes, were available, more specific measures of carbon values for OCS planning areas, which were found in published studies and reported by BLM's OCS field offices. By and large, these are not inconsistent with the above ratings or the more generalized values included in column 1. While the specific measures are somewhat lower than values in the more generalized ranges, they are generally within the same order of magnitude. They also correspond to a particular sampling point which may or may not be reflective of the planning area as a whole. However, while the ranges provide the best measure of primary productivity for entire planning areas, they may not be a very accurate reflection of productivity for specific portions of the planning areas.

Other Measures of Biological Productivity

Another possible measure of biological productivity is benthic biomass. However, we were less successful at developing benthic production estimates for different planning areas (especially Alaskan areas) than for primary production. Therefore, primary productivity will be used as the chief biological indication of marine productivity.

Figure 1 shows generally the relationship of primary production to the larger living marine resources more familiar to the average person, and perhaps of more immediate interest. The figure is simplified, and leaves out many important elements of the marine food web and its complex interactions, such as the role of bacteria that release nutrients from dead plant and animal material. Based on this figure, it would seem that there might be a direct relationship between primary productivity and number of larger animals supported. Of course, the primary productivity figures reported in Table 10 are for ocean areas, and many of the resources of concern depend at least partially on coastal habitat. Nonetheless, while primary productivity does influence the type and numbers of higher species supported, there are many other factors also affecting potential productivity of larger living marine resources. Community structure, predator-prey relationships, competition, and migratory behavior are examples of factors affecting the numbers and distribution of marine resources. Table 6 indicates the abundance of some of these other marine resources by planning area. Because these are totals, they do not take into account the fact that the sizes of planning areas vary significantly. Despite this, it can be seen that some areas with lower primary productivity are extremely productive for some species or group. In particular, it may be worth noting that Alaska provides the sole breeding grounds for some birds [illegible] which migrate to three continents.

Economic Productivity

Of principal concern to many is the economic productivity of different OCS planning areas. Table 7 shows some estimates and measures of economic productivity. The potential for commercial fish harvest is probably of the greatest interest. However, the catch data shown here do not give a very good indication of productivity or even economic potential. In some OCS areas in Alaska, the commercial fishing potential has barely been tapped. Other areas have been overfished for some species, and therefore are not currently supporting the numbers of some stock which, without human interference, they could support.

Estimates of total stock would be one of the best measures of potential economic productivity as well as a good indicator of biological productivity. However, these are only available for some regions and some species covered by Fisheries Management Plans. Other measures of productivity which have been suggested include catch per area and catch per level of effort. Unfortunately, these are not good measures of productivity for comparing regions where level of harvesting activity varies greatly, and statistics are difficult to obtain. Most statistics on level of effort address individual species and their availability is uneven. Catch per area statistics are also not uniformly available and are based on widely different units.

Conclusion

Different OCS areas may be characterized as more or less productive, based on primary productivity or other resources discussed previously. However, it is important to recognize that oceans and especially coastal areas are generally very productive. Differences between average productivity levels of various areas are probably not as significant as differences within each OCS area.

Table 7
Economic Productivity by Planning Area

Planning Area	Commercial Fisheries Harvest Value (Ex-vessel) 1/ $ million (1981)	Recreational Fisheries Value 2/ $ million (1981)	Recreational Hunting Value (based on breeding waterfowl) 3/ $ million (1981)
North Atlantic	609.2	1,289	small
June 1980 N. Atl.	304.1	300	small
June 1980 Mid-Atl.	305.1	989	small
South Atlantic	175.1	713	58.5
Eastern Gulf of Mex.	82.4	559	6.5
Central Gulf of Mex.	253.1	254	162.5
Western Gulf of Mex.	169.3	393	162.5
Southern California	302.4	268	.065
Cen. & N. Calif.	53.9	166	.065

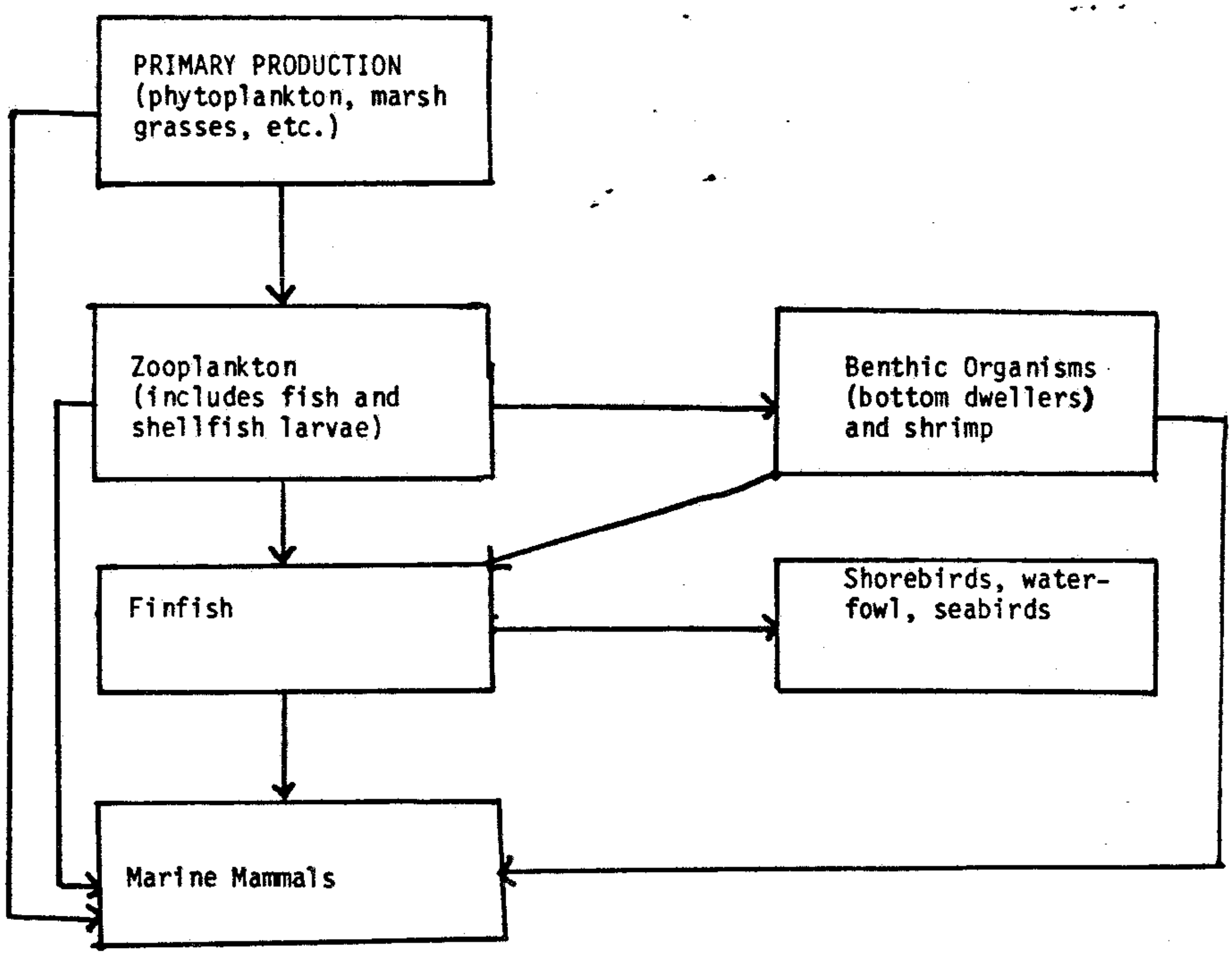
Table 7 (continued)

Gulf of Alaska	544	little or none	19.5
Kodiak	55	" " "	13
Shumigan	with N. Aleut. Basin	" " "	?
Cook Inlet	10	" " "	6.5
N. Aleutian Basin	181.3	" " "	390
St. George Basin	with N. Aleut. Basin	" " "	6.5
St. Matthew-Hall Basin	?	" " "	260
Navarin Basin	?	" " "	?
Norton Basin	2	" " "	?
Hope Basin	.5	" " "	130
Barrow Arch	?	" " "	104
Diapir Field	?	" " "	104

1/ See footnote 3/, Table 6.
2/ Derived by multiplying average cost per trip (by type) by estimated number of trips (by type), from U.S. Department of Commerce (N OAA/NMFS) Marine Recreational Fishery Statistics Survey, Atlantic and Gulf Coast, 1979, to obtain expenditures. Based on a 1981 study by the Granville Corp., these costs appear to be roughly 1/3 of the value of the fishing trips to fishermen. Therefore, expenditures were tripled to obtain estimates of value. Since data was not obtained for California, a value/weight ratio was applied to obtain recreation values for California planning areas.
3/ Based on an average 1981 $ value of $65/bird, based on a U.S. Fish and Wildlife Study, and numbers of breeding waterfowl reported by BLM's OCS offices.

Figure 1

Marine and Coastal Food Web



C. Expected External Costs

In addition to the analysis of relative environmental sensitivity and marine productivity of OCS areas, a quantitative analysis was made of some of the potential external costs* which might be associated with development of the recoverable hydrocarbon resources in each of the OCS planning areas. While the estimated external costs are associated with the development of the resources of each of the planning areas, they must be viewed as costs to the nation as a whole. This is so since the costs do not necessarily accrue to the residents living in areas adjacent to the planning areas on a one to one basis.

Of the potential OCS oil and gas damages that could occur, the analysis was restricted to those for which cost data (in dollars) exist and, in the judgment of the staff of the Interior Department, 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 are described in the FEIS, SEIS and elsewhere in the SID. These descriptions, along with this external cost analysis, will allow the Secretary to consider variations in potential environmental damage and adverse coastal zone impacts from planning area to planning area in selecting the "timing and location of leasing."

In this analysis, estimates related to oil spills of 1000 barrels or more were made for potential ecological damages, tourism and recreation losses, commercial fishing losses, real property losses, legal expenses, subsistence life-style losses, the value of oil spilled, research and surveillance expenses, spill control and clean-up costs. Estimates were also made for potential air quality losses and onshore habitat losses. Damages from oil spills less than 1000 barrels and damages associated with transport of gas were not estimated for lack of data useful to this analysis. These damages, however, are expected to be modest in comparison to those estimated.

Estimates of the costs in each category of damage were based on data and judgments derived from the results of a literature search, the FEIS and final SEIS, the preceding analysis of relative environmental sensitivity and relative marine productivity, knowledge of the value of other uses of the sea, the estimated amount of oil and gas production, the likelihood of resulting damage in each area and a number of other factors. A description of the expected external cost analysis is presented in Appendix 8 and is summarized in Tables 8 and 9 below.

---

* External costs include environmental and socio-economic costs which are not normally included in the costs of operations involved in OCS oil and gas exploration, development, production and transportation.

Table 8 shows that the estimates associated with the development of the expected resource in each planning area range from a net total external benefit of $920 million to a net total external cost of $2.2 billion for the Central Gulf of Mexico and Diapir Field, respectively. Table 8 shows that external benefits are expected to result from the development of resources in the Central and Western Gulf of Mexico. This is the case since production of oil from these areas is piped to market and thus substitutes for or "backs out" imported oil which would otherwise be tankered to the United States and causes significantly greater expected oil spill damage.

Because the total expected external cost is a function of the amount of resource produced, the development of a planning area with a small amount of estimated hydrocarbon resources, such as Hope Basin or Shumagin, will in general, result in a relatively small total expected external cost. The converse is also generally true, with some exceptions which will be explained in the discussion of Table 9 below.

A comparison of the first column of Table 9 with Table 8 shows a number of differences between the ranking of the leasing areas by expected external costs per barrel of oil equivalent (BOE) compared to the total expected external costs. The Central and Western Gulf of Mexico are ranked lowest by both measures. Moreover, these two areas are expected to provide 92 cents and 45 cents per BOE, respectively, of external benefits to the nation as a whole. On the other hand, the estimated resources of the Eastern Gulf of Mexico and Central and Northern California would be expected to be the most expensive to develop with respect to the expected external costs per BOE accruing to the nation as a whole (53 cents and 44 cents per barrel, respectively).

The following observations can be made from the analysis of Appendix 8 as summarized by Table 9. If none of the area's oil resources are expected to be transported by tanker (e.g., Central and Western Gulf of Mexico), an external benefit is expected to result rather than an expected external cost. For an area in which a small percent of the hydrocarbon resources is expected to be oil, the expected external costs per BOE are relatively low even if all the oil is transported by tanker (e.g., Hope Basin--see 1st and 2nd columns of Table 9). Likewise, even if the percent of hydrocarbons which are expected to be oil is high, the expected external costs per BOE are expected to be relatively low if a large portion of the oil is not transported by tanker (e.g., Southern California). For an area in which a high percent of the estimated hydrocarbon resources is expected to be oil, and all the oil is expected to be transported by tanker, the expected external cost per BOE is expected to be relatively high (e.g., Eastern Gulf of Mexico--see 1st and 2nd columns of Table 9). These observations help demonstrate that of the potential damages examined in the analysis, the dominating influence in determining the expected external cost per BOE is the expected damage from transportation of oil by tanker. The analysis of Appendix 8 shows that about twenty times more oil per barrel transported is expected to be spilled from tankers than from pipelines. As such, the external costs associated with damage from oil spills from tankers far overshadow all other sources of damage considered in the analysis.

Table 8
OCS Planning Areas Ranked by
Total Expected External Costs
(Environmental and Socio-Economic) in $ Billion
Associated with Development of All the
Resources In Each Planning Area

	External Costs of Development of Expected Recoverable Resources ($billions)
1. Central Gulf of Mexico	- .92 *
2. Western Gulf of Mexico	- .45 *
3. Hope Basin	.01
4. Shumagin	.06
5. Cook Inlet	.08
6. Norton Basin	.12
7. North Aleutian Basin	.14
8. North Atlantic	.18
9. Kodiak	.25
10. Gulf of Alaska	.27
11. St. George Basin	.34
12. South Atlantic	.38
13. Southern California	.40
14. Navarin Basin	.45
15. Central and Northern California	.46
16. Barrow Arch	.55
17. Eastern Gulf of Mexico	.69
18. Diapir Field	2.22
(Old North Atlantic)	(.02)
(Old Mid-Atlantic)	(.13)
(St. Matthew-Hall)	(-)

* A negative expected external cost, e.g. -$.92 billion dollars, indicates a gain rather than a loss in those resources and values analyzed. Such net benefits result and accrue to the nation as a whole when the external costs associated with development of the area's resources are less than the oil spill costs foregone from "backing out" foreign crude oil imported in tankers. For further explanation of costs foregone from foreign imports see Appendix 8-D-0.

Table 9

OCS Planning Areas Ranked by Expected External Cost In $ Per Barrel of Oil Equivalent (BOE)

		External Cost in Dollars Per BOE	Percent of BOE Which Is Oil	Percent of Oil Transported At Least Part of Route By Tankers
1.	Central Gulf of Mexico	-.10 *	34	0
2.	Western Gulf of Mexico	-.07 *	24	0
3.	North Atlantic	.03	57	67
4.	Southern California	.17	76	50
5.	Hope Basin	.20	29	100
6.	South Atlantic	.24	60	100
7.	Navarin Basin	.24	47	100
8.	Norton Basin	.32	42	100
9.	Shumagin	.33	44	100
10.	Cook Inlet	.36	43	100
11.	Kodiak	.36	49	100
12.	St. George Basin	.37	50	100
13.	Gulf of Alaska	.39	50	100
14.	North Aleutian Basin	.40	54	100
15.	Diapir Field	.41	51	100
16.	Barrow Arch	.43	55	100
17.	Central and Northern California	.44	80	75
18.	Eastern Gulf of Mexico	.53	83	100
	(Old North Atlantic)	(.01)	(58)	(67)
	(Old Mid-Atlantic)	(.03)	(57)	(67)
	(St. Matthew-Hall)	(-)	(-)	(-)

* A negative expected external cost, e.g. -10 cents per BOE, indicates a gain rather than a loss in those resources and values analyzed. Such net benefits result and accrue to the nation as a whole when the external costs associated with development of the area's resources are less than the oil spill costs foregone from backing and foreign crude oil imported in tankers. For further explanation of costs foregone from foreign imports see Appendix 8-D-O.

Appendix 8 also demonstrates that of the potential expected external costs which were measured, the greatest portion is expected to be attributable to possible ecological damage from large oil spills reaching the coastal zone. In fact, potential ecological costs are expected to be several times greater than external socio-economic costs.

Ecological losses from oil spills are generally expected to be higher per barrel of oil when tankers are used to transport oil to shore and when spills are more likely to hit a coastal area with valuable, oil-sensitive ecological resources. This is so, due to the expected spill rate for tankers and because ecological damage, should a spill occur, is expected to be greater nearshore and onshore than in the open ocean and greater in coastal areas with economically valuable, oil-sensitive resources than for areas with relatively barren shores and nearshore waters. Also, the amount of oil spilled is expected to be roughly proportional to the amount of oil produced and transported. Thus, the expected amount of the oil resource, the distance of the oil platform from shore, the value and sensitivity of potentially threatened ecological resources, and the mode and route of transport are four of the prime factors which determine the magnitude of expected external costs of spills over 1000 barrels in this analysis.

Ecological costs per barrel of oil spilled for spills over 1000 barrels from platforms are expected to be relatively low for Navarin Basin and the North Atlantic due to the relatively low occurrence of sensitive, valuable habitats and the relatively low chance of spills reaching them. The corresponding ecological costs are expected to be moderate for the South Atlantic and moderate to high for all the other planning areas (See Appendix 8-C-1). However, when the total expected ecological costs of production are considered, the development of the resources of Central and Western Gulf of Mexico are expected to result in lowest costs of all the planning areas because no tankers are anticipated to be used for transport of these resources. The North Atlantic and Southern California are expected to have moderate total ecological costs due in part to use of pipelines rather than tankers for transport of some of the estimated oil resources. The other planning areas are expected to have moderate to high total ecological costs on a relative basis. (See Appendix 8-C-1).

Expected socio-economic costs, while small relative to ecological costs, vary considerably depending on the leasing area. For instance, recreation losses caused by oil spills from platforms are expected to be relatively high per barrel for Southern California, relatively low in the Alaskan areas and moderate elsewhere. Also, expected losses to subsistence life-styles are significant in some areas of Alaska but assumed to be negligible outside Alaska. The expected cost of oil spill control and clean-up varies considerably from area to area, too. (See Appendix 8-C-1.)

Losses per barrel due to air pollution were assumed to be negligible in all the Alaskan areas except Norton Sound, where they are estimated to be very low. Air pollution losses in areas of the contiguous 48 States range from relatively low to moderate except for the California areas, where they are expected to be relatively high per barrel, due in large part to the concentrated coastal population and the climate. (See Appendix 8-C-2.)

Wetland habitat losses from onshore development are expected to be relatively large for Barrow Arch and somewhat less for all the other areas except the North Atlantic, the Central and Western Gulf of Mexico and the California areas, for which such losses are expected to be quite small on a relative basis. The key determinants of these estimates are the percent of onshore support areas expected to be located in wetlands, the degree to which support facilities exist, and the amount and duration of onshore support activity. (See Appendix 8-E-2.)

A full description of all the potential costs estimated for this analysis is presented in Appendices 8-C-1, 8-C-2 and 8-D-0. The summary to Appendix 8 also provides a more detailed explanation of the analytical approach, the meaning of "external costs", the method of calculation, the data sources used, and the reliability of estimates.

The above discussion and the estimates given in Appendix 8 must be considered in light of two important points. First, the estimates may largely overstate the costs, and second, due to the high uncertainty, the estimates must be used cautiously. The estimates were made to comply with Section 18 of the OCSLA and the opinion of the Circuit Court of Appeals of the District of Columbia in California vs. Watt, dated October 6, 1981. They were made using an "uneasy calculus" as the Court recognized might be necessary.

When judgments were needed on the dollar value to use for damages or how an area's environmental resources should be rated, the practice was always made to err on the high side. For instance, ecological damages are difficult to assess and even more difficult to value in terms of dollars. The same is the case for subsistence losses. As Appendix 8 explains, in attempting to solve these difficult quantification problems, costs probably have been overstated.

Another and vitally important reason that the estimates of expected external costs are likely overstated is that development of the United States' OCS oil and gas resources is conducted in an exceedingly safe and environmentally sound manner. The program has, compared to other developmental programs, an outstandingly low record of personnel and mechanical failures which have resulted in environmental damage or adverse coastal zone impacts. Advances in technology have lowered and can be expected to continue to lower the chance of such damage and impacts. The substantial OCS oil and gas scientific program of the Department of the Interior 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 Interior Department have mitigated and will continue to mitigate many of the potential damages. Furthermore, the compensation provisions of the OCS Lands Act (while not reflected in this external cost analysis) provide a means to compensate those who are adversely affected in the event that damage occurs.

As indicated above, the other important point which must be kept in mind in assessing the results of this analysis is 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 and opinion, the external cost estimates should be considered, at best, as an order of magnitude approximation. As such, prudent use of these estimates would only make distinctions between differences from area to area if they are approximately an order of magnitude in size (that is, one estimate is more than or less than 10 times the other). For instance, it would be reasonable to regard the development of the resources of the Hope Basin, Shumagin, Cook Inlet, Norton Basin, North Aleutian Basin and the North Atlantic as having significantly lower total external costs than development of the resources of Diapir Field. Such a conclusion is reasonable because the external cost estimates differ by two orders of magnitude (e.g., $12 million vs. $2 billion - see Table 8). On the other hand, to presume that the total external costs associated with the development of the resources of Eastern Gulf of Mexico will be significantly higher than those associated with the Gulf of Alaska would be, at best, a marginally credible presumption.

D. Equitable Sharing of Developmental Benefits and Environmental Risks

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

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

Estimates of both developmental benefits and environmental risks have been calculated on a planning area basis. While we can attribute certain benefits and risks to activity in a particular planning area or region of the OCS, how these benefits and risks are shared by the population onshore is not as obvious. Developmental benefits are largely captured in the form of Federal revenues and to a lesser extent in the form of corporate profits. In addition, some individuals and firms whose labor, land, materials or equipment are used in OCS development regard the purchase of those resources as a benefit. Of course, from the viewpoint of the nation, this use of their resources is not a benefit because it means that they cannot be used in other productive ways. This is reflected by the fact that the costs of these inputs are subtracted from production revenues in estimating net economic value.

The sharing of benefits among the population in coastal States varies depending upon the form of the benefit. Most developmental benefits are captured in the form of Federal revenues. It is not clear exactly how the benefits derived from increased Federal revenues would be shared. From one perspective, they would be distributed in about the same way Federal taxes are distributed because without OCS revenues the Federal Government would have to collect more taxes. 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 resources of the OCS are owned by the public.

Benefits that arise in the form of corporate profits are distributed to people in the form of stock dividends. This distribution tends to be quite wide nationally speaking--it is certainly not likely to be concentrated in coastal areas. On the other hand, many of the perceived benefits from purchase of inputs used in OCS development tend to fall within the coastal areas providing the labor and materials used offshore. Neither of these forms of benefit is likely to be significant in comparison to the increases in Federal revenues. For this reason, it is reasonable to focus the consideration of an equitable sharing of developmental benefits primarily on the distribution 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. There are relatively few differences among the three. The one exception is that Alaska's share of Federal funds paid to State and local governments is about 3 times greater than its share of tax payments and population.

Table 10. Distribution of Net Economic Value Resulting from Total Production Among Regions.

Region	Share of Total Net Economic Value In Proportion To Federal Tax Payments		Share of Total Net Economic Value In Proportion To Population		Share of Total Net Economic Value In Proportion To Federal Intergovernmental Funds	
	Percent	$ Billions	Percent	$ Billions	Percent	$ Billions
I. Maine, New Hampshire Massachusetts, Rhode Island, Connecticut New York, New Jersey Delaware, Maryland Virginia	25	117	21	98	23	108
II. North Carolina South Carolina Georgia	4	19	6	28	6	28
III. Florida	3	14	4	19	3	14
IV. Texas, Louisiana Mississippi, Alabama	10	47	11	151	10	47
V. California	11	51	10	47	11	51
VI. Washington, Oregon	3	14	3	14	3	14
VII. Alaska	0.2	1	0.2	1	0.6	3

The distribution of environmental costs among the population tends to be skewed toward residents of coastal States. These people are the most direct beneficiaries of the use of the environmental resources that may be adversely affected by OCS development. Thus, the estimated external costs for each area were allocated in Table 11 to the adjacent and nearby States with the exception of the external costs from areas of the Alaska OCS. Because a substantial portion of these costs result from tanker spills during shipment to the lower 48 States, a substantial portion of the external costs resulting from oil and gas development offshore Alaska were allocated to Washington-Oregon and California with the greater share allocated to California because of terminal 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. In order to determine how the various regions share in the net change in external costs with OCS development as compred to without OCS development, the damages from spills of tankered oil imports were backed out of the external cost distribution. This was done by examining the regional distribution of oil imports and estimating the approximate regional pattern of substitution of OCS oil for imported oil. Table 11 shows the results in the right hand columns. The Gulf of Mexico and the North Atlantic States benefit most from the back out of oil imports because of the substantial imports they receive.

The effects of compensation paid to individuals suffering damage were not considered in estimating external costs. Table 11 summarizes the distribution of external costs remaining after compensation for oil spill damages under Title III of the OCS Lands Act Amendments. Title III establishes liability for spills of OCS oil and provides for compensation by the source of the spill or the Oil Spill Pollution Fund for a wide range of oil spill damages. The Fund is financed by fees from OCS producers, but can borrow if necessary to pay claims. The compensation estimates were based on the assumption that only half of the total external costs would be compensated for. This reduces the damages borne by each region (without backing out import spills) by 50%. On the other hand, it would only reduce each regions' share of the benefits by 1%. This results from the fact that compensation totalling $5.6 billion over the 30 years of production would be subtracted in the form of insurance premiums, fees paid to the Fund, and claim settlements paid directly by oil spill sources from the amounts otherwise available to pay bonuses and tax revenues to the Federal Government.

Table 11 shows that nature has not distributed oil and gas resources and affected environmental resources evenly. It also shows that Alaska, because of its long coastline and sensitive environment, would bear relatively high costs. On the other hand, because of its small population, small contribution to Federal tax receipts, and small receipt of Federal funds, Alaska, is thus allocated little of the benefits. California would also bear high costs, in part because of tankering of oil from Alaska areas. Unlike Alaska, however, California receives a substantial amount of the benefits.

Compensation for damages from oil spills through the provisions of Title III of the OCS Lands Act Amendments would even out the distribution of costs and benefits substantially. Because strict liability is established and the Offshore Oil Pollution Compensation Fund (Title III) is authorized to pay damages when a source is not determined or liability limits are exceeded, the damages from oil spills will be substantially compensated. Since both private payments and payments from the Fund have the effect of reducing Federal lease revenues and tax revenues flowing to the Treasury, the effect of this compensation mechanism is to reduce the benefits to all States by the same small proportion while reducing the external costs borne by the coastal States very substantially. Thus Alaska, for example, might have its share of the benefits reduced by less than 2% while the uncompensated external costs it bears would be reduced by 50%.

In conclusion, the developmental benefits of OCS leasing are shared widely while the natural distribution of oil and gas and environmental resources at risk concentrates the environmental risks in coastal areas. As pointed out in the discussion of external cost estimates, the environmental risks are closely related to the extent of oil tankering. Areas of substantial oil production which is brought to market via tankers rather than pipelines will bear higher environmental risks. The resulting unevenness in the distribution of environmental risks is partially reduced by the reduction in spills of oil being tankered to U.S. markets from abroad. The uneven burden of environmental risks is also reduced by compensation that will be provided to those suffering damages from oil spills. Further reductions in the unevenness of environmental risk could be achieved by increasing compensation or by restricting leasing in areas of higher environmental risk. Restricted leasing, of course, would reduce the benefits to the Nation as a whole. Such reductions would need to be substantial in order to change markedly the distribution of environmental risk.

Table 11. Distribution of External Costs from Total Production
($ Billions)

Regions	Share of External Costs Without Import Spills Backed Out		Share of External Costs With Import Spills Backed Out	
	Without Compensation	With Compensation	Without Compensation	With Compensation
I. Maine, New Hampshire Massachusetts, Rhode Island, Connecticut New York, New Jersey Delaware, Maryland Virginia	1.0	.5	-.1*	-.6*
II. North Carolina South Carolina Georgia	.7	.4	.7	.4
III. Florida	1.0	.5	1.0	.5
IV. Texas, Louisiana Mississippi, Alabama	.5	.3	-1.7*	-2.0*
V. California	4.0	2.0	3.4	1.4
VI. Washington-Oregon	.3	.2	.3	.2
VII. Alaska	3.6	1.8	3.6	1.8

* A negative expected external cost, e.g., -$.1 billion dollars, indicates a gain rather than a loss in those resources and values analyzed. Such net benefits result and accrue to the Nation as a whole when the external costs associated with development of the area's resources are less than the oil spill costs foregone from "backing out" foreign crude oil imported in tankers. For further explanation of costs foregone from foreign imports see Appendix 8-D-0.

E. 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."

The general interpretation of this requirement is that an area should be included if the benefits of oil and gas activities there exceed the costs, and 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 external costs, including the types of damages listed in §18(a)(2), have been calculated as previously discussed. These estimates have been used to calculate estimates of the net social value by planning area. Table 12 ranks the planning areas by their estimated net social value. Since all of the 18 areas included in the July 1981 proposed program have a positive net social value--net economic value minus external costs--they all deserve further consideration based on these estimates.

With respect to the timing question, the net social value rankings can be used to divide the planning areas into the following three groups, based on order of magnitude:

I. High	Central Gulf of Mexico Western Gulf of Mexico
II. Medium	North Atlantic Diapir Field Southern California Navarin Basin Eastern Gulf of Mexico South Atlantiic Central and Northern California Barrow Arch
III. Low	St. George Basin Gulf of Alaska Kodiak North Aleutian Basin Norton Basin Cook Inlet Shumagin Hope Basin

The following timing guidelines would be consistent with this grouping:

-- annual offerings in the Central and Western Gulf of Mexico;

-- biennial offerings in the North Atlantic, Diapir Field, Southern California, Navarin Basin, Eastern Gulf of Mexico, South Atlantic, Central and Northern California, and Barrow Arch; and

-- less frequent offerings in St. George Basin, Gulf of Alaska, Kodiak, North Aleutian Basin, Norton Basin, Cook Inlet, Shumagin, and Hope Basin.

Planning areas have also been ranked by relative environmental sensitivity and marine productivity (see Part II.B.). To the extent possible, these considerations are reflected in the net social value rankings. However, since many of the environmental considerations can only be viewed in qualitative terms, the environmental and productivity rankings need to be viewed separately from the net social value rankings.

Special attention should be paid to the environmental sensitivity ranking for Diapir Field and Central and Northern California, which have "Next to Highest" ranking whereas the net social value numbers support biennial leasing. With respect to marine productivity, attention should be paid to North Atlantic, Southern California, and Central and Northern California which are ranked "Next to Highest," but net social value calcuations support biennial leasing.

Industry interest supports the pace of leasing off the contiguous 48 States which would be derived from the ranking of the areas by net social value (see Appendix 5). With specific regard to the Eastern Gulf of Mexico, industry has expressed a much lower interest there than the Central and Western Gulf when asked for such a comparison. Answers to the last request for such information distinguishing between areas in the Gulf of Mexico were received in 1979.

With respect to Alaska, recently expressed interest would argue in favor of biennial offerings in St. George Basin, Norton Basin, and North Aleutian Basin which would be a deviation from a schedule based solely on net social value rankings.

The Secretary will need to consider the conclusions which can be drawn from the net social value estimates and rankings, collectively with the information discussed above with the other qualitative information presented in this document, its appendices and the FSEIS.

Table 12. Ranking of Planning Areas by Expected Net Social Value of Development of Estimated Recoverable Resources

	Expected Net Economic Value of Development of Expected Recoverable Resources ($billions) (see table 3)	Expected External Costs of Development of Expected Recoverable Resources ($billions) (see table 8)	Expected Net Social Value ($billions) (col. 1 - col. 2)
1. Central Gulf of Mexico	128	-.92	129
2. Western Gulf of Mexico	82	-.45	82
3. North Atlantic	67	.18	67
4. Diapir Field	47	2.22	45
5. Southern California	36	.40	36
6. Navarin	18	.45	18
7. Eastern Gulf of Mexico	17	.69	16
8. South Atlantic	15	.38	15
9. Central & Northern California	14	.46	14
10. Barrow Arch	11	.55	10
11. St. George Basin	8	.34	8
12. Gulf of Alaska	7	.27	7
13. Kodiak	7	.25	7
14. North Aleutian Basin	3	.14	3
15. Norton Basin	3	.12	3
16. Cook Inlet	2	.08	2
17. Shumagin	2	.06	2
18. Hope Basin	0.8	.01	0.8
(North Atlantic 6/80)	(20)	(.02)	(20)
(Mid-Atlantic 6/80)	(45)	(.13)	(45)
(St. Matthew-Hall)	( )	(-)	(-)

III. Analysis of Alternative Leasing Programs

A. Analysis of Alternative Leasing Schedules Included in Final SEIS

The Final SEIS analyzes the environmental effects of five lease schedules, including the effects of alternative ways of defining sale offerings. These schedules were the result of activities conducted up to the time of the issuance of the July proposed program, and the scoping process conducted by BLM under NEPA. These alternatives are now analyzed in terms of section 18 considerations drawing upon analyses in earlier parts of this document and its appendices. Following this section, an additional alternative is developed and described which is based, in part on the qualitative analysis discussed earlier. It should be considered, however, only as an example because other schedules are possible which exhibit a "proper balance." This is because arriving at a "proper balance" is more than a mechanical determination based on factors which can be quantified with a high degree of precision. Not only is the quantitative analysis uncertain, but several factors must be considered in a subjective manner.

The July 1981 proposed program serves as the primary alternative (Alt. I) in the Final SEIS. The other alternatives are the April 1981 draft proposed program (Alt. II), the June 1980 program (Alt. III), a program which delays, defers, and accelerates certain sales off Alaska (Alt. IV--delayed sales are: #70 - St. George Basin, from 1983 to 1986, #83 - Navarin Basin, from 1984 to 1985, #85 - Barrow Arch, from 1985 to 1986, and #86 - Hope Basin, from 1985 to 1986; deferred sales are: #75 and #92 - North Aleutian Basin, #88 - Norton Basin, #89 and 101 - St. George Basin, and #107 - Navarin Basin; accelerated sales are: #100 - South Alaska, and #97 - Diapir Field) and one which defers all Alaskan sales in the arctic (Alt. V). Four of the alternatives have also been analyzed in terms of three alternative ways of defining sale offerings. The three possibilities are traditionally sized tract selection, larger tract selection, and area-wide offerings. Area-wide offerings are further divided into the July 1981 proposal and the preliminary refinement decision of December 15, 1981. It should be noted that Alternative III ends in June 1985, whereas the other alternatives extend through 1986. This is because that schedule is the June 1980 program and represents the "no action" alternative in the Final SEIS.

The following notations will be used in describing each alternative, and variations thereof:

Alternative I-1. July 1981 proposed program with area-wide offerings as they were described in July 1981.

Alternative I-2. July 1981 proposed program with area-wide offerings as refined in the December 15, 1981 preliminary decision.

Alternative II. April 1981 draft proposed program with area-wide offerings

Alternative III-1. June 1980 program with traditionally sized tract selection

Alternative III-2. June 1980 program with larger tract selection

Alternative IV-1. Defer and delay Alaskan sales (modification of July 1981 proposal) with area-wide offerings (July 1981 description)

Alternative IV-2. Defer and delay Alaskan sales (modification of July 1981 proposal) with area-wide offerings (December 15, 1981 refinement)

Alternative V-1. Defer arctic sales, (modification of July 1981 proposal) with area-wide offerings (July 1981 description).

Alternative V-2. Defer arctic sales (modification of July 1981 proposal) with area-wide offerings (December 15, 1981 refinement)

Tables have been prepared displaying the following information:

- ° Table 13 shows the sales proposed in each of the alternatives by year.
- ° Table 14 shows statistical characteristics of each alternative.
- ° Table 15 shows the estimates of developmental benefits and environmental risks by alternative.
- ° Table 16 shows 18(a)(3) balancing considerations
- ° Table 17 shows estimates of appropriations and staff for each alternative.

Table 16 illustrates characteristics of each alternative schedule relating to the 18(a)(3) requirement 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"

Planning areas which are used to designate the location of sales are listed in order of net social value (see Table 12). To the extent the factors listed in § 18(a)(3) are quantifiable, the estimate of net social value serves as one measure for determining the timing and location of sales. Subject to consideration of the numerous qualitative aspects of section 18, a positive net social value would support inclusion of a planning area on a schedule--the location question. With respect to timing, a relative high net social value would support early and frequent offering whereas a lower value might argue for less frequent offerings. The number of sales and years in which the sales are proposed in each schedule provide an indication of consistency with these concepts.

Also shown on Table 16 are the environmental sensitivity and marine productivity rankings of the planning areas since these factors could not be completely incorporated in the net social value calculations. Additional qualitative considerations are addressed in the SEIS and should also be evaluated in determining a proper balance. Industry interest is not shown since the information provided by industry was not in a form compatible with these planning areas (see Appendix 5). In determining a proper balance, industry interest needs to be carefully considered since in several instances industry's judgment on the relative ranking of areas differs from the USGS, and the USGS estimates have a significant effect on the net social value calculations. Specifically, in contrast with the net social value figures which rely heavily on USGS estimates, industry interest argues in favor of frequent leasing in St. George Basin, Norton Basin, and North Aleutian Basin.

Table 13
SUMMARY OF ALTERNATIVE SCHEDULES IN FINAL SEIS

Alt. I-1 and I-2

1982

67 Gulf of Mexico
68 S. California
RS-2
52 N. Atlantic
71 Diapir Field
69 Gulf of Mexico
57 Norton Basin

1983

73 CAM California
70 St. George Basin
76 Mid Atlantic
75 N. Aleutian Basin
72 C. Gulf of Mexico
78 S. Atlantic
74 W. Gulf of Mexico
79 E. Gulf of Mexico

1984

80 S. California
82 N. Atlantic
83 Navarin Basin
81 C. Gulf of Mexico
87 Diapir Field
84 W. Gulf of Mexico
88 Norton Basin
94 E. Gulf of Mexico
89 St. George Basin

1985

90 Atlantic
85 Barrow Arch
91 CAM California
92 N. Aleutian Basin
98 C. Gulf of Mexico
86 Hope Basin
102 W. Gulf of Mexico
100 S. Alaska
103 E. Gulf of Mexico

1986

95 S. California
96 Atlantic
107 Navarin Basin
104 C. Gulf of Mexico
97 Diapir Field
105 W. Gulf of Mexico
99 Norton Basin
106 E. Gulf of Mexico
101 St. George Basin

Alt. II

1982

67 Gulf of Mexico
68 S. California
57 Norton Basin
RS-2
52 North Atlantic
71 Diapir Field
69 Gulf of Mexico
70 St. George Basin

1983

73 California
76 Mid Atlantic
75 N. Aleutian Basin
72 Gulf of Mexico
RS-3
78 S. Atlantic
74 Gulf of Mexico
83 Navarin Basin

1984

80 California
82 N. Atlantic
87 Diapir Field
79 Gulf of Mexico
88 Norton Basin
RS-4
89 St. George Basin
81 Gulf of Mexico

1985

85 Barrow Arch
90 Atlantic
91 California
84 Gulf of Mexico
RS-5
92 N. Aleutian Basin
86 Hope Basin
93 St. Matthew Hall
94 Gulf of Mexico

1986

95 California
96 Atlantic
97 Diapir Field
98 Gulf of Mexico
RS-6
99 Norton Basin
100 S. Alaska
101 St. George Basin
102 Gulf of Mexico

Alt. III-1 and III-2

1982

67 Gulf of Mexico
RS-1
68 S. California
69 Gulf of Mexico
57 Norton Basin
52 North Atlantic
70 St. George Basin

1983

71 Diapir Field
72 Gulf of Mexico
73 California
RS-3
74 Gulf of Mexico
75 N. Aleutian Basin
76 Mid Atlantic

1984

78 South Atlantic
79 Gulf of Mexico
RS-4
80 California
81 Gulf of Mexico
82 N. Atlantic
83 Navarin Basin

1985

84 Gulf of Mexico
85 Barrow Arch
86 Hope Basin
RS-5

Alt. IV-1 and IV-2

1982

67 Gulf of Mexico
68 S. California
RS-2
52 North Atlantic
71 Diapir Field
69 Gulf of Mexico
57 Norton Basin

1983

73 CAM California
76 Mid Atlantic
72 C. Gulf of Mexico
78 S. Atlantic
74 W. Gulf of Mexico
79 E. Gulf of Mexico

1984

80 S. California
82 N. Atlantic
81 C. Gulf of Mexico
87 Diapir Field
84 W. Gulf of Mexico
100 S. Alaska
94 E. Gulf of Mexico

1985

90 Atlantic
91 C & N California
98 C. Gulf of Mexico
83 Navarin Basin
102 W. Gulf of Mexico
97 Diapir Field
103 E. Gulf of Mexico

1986

95 S. California
96 Atlantic
70 St. George Basin
104 C. Gulf of Mexico
99 Norton Basin
105 W. Gulf of Mexico
85/86 Hope/Barrow
106 E. Gulf of Mexico

Alt. V-1 and V-2

1982

67 Gulf of Mexico
68 S. California
RS-2
52 North Atlantic
69 Gulf of Mexico
57 Norton Basin

1983

73 CAM California
70 St. George Basin
76 Mid Atlantic
75 N. Aleutian Basin
72 C. Gulf of Mexico
78 S. Atlantic
74 W. Gulf of Mexico
79 E. Gulf of Mexico

1984

80 S. California
82 N. Atlantic
83 Navarin Basin
81 C. Gulf of Mexico
84 W. Gulf of Mexico
88 Norton Basin
94 E. Gulf of Mexico
89 St. George Basin

1985

90 Atlantic
91 N & C California
92 N. Aleutian Basin
98 C. Gulf of Mexico
102 W. Gulf of Mexico
100 S. Alaska
103 E. Gulf of Mexico

1986

95 S. California
96 Atlantic
107 Navarin Basin
104 C. Gulf of Mexico
105 W. Gulf of Mexico
99 Norton Basin
106 E. Gulf of Mexico
101 St. George Basin

Table 14

Statistical Characteristics of Alternative Schedules

	I-1 & I-2	II	III-1	III-2	IV-1 IV-2	V-1 V-2
Oil and Gas Statistics						
Total Oil (billion barrels)	8.3	8.2	3.6	4.2	7.8	6.5
Total Gas (trillion cubic feet)	39.5	38.1	19.1	20.0	35.6	27.6
Number of Exploratory Wells	1,562	1,560	1,076	1,076	2,629	1,503
Number of Development and Production Wells	5,152	5,109	2,706	3,218	8,385	4,985
Oil Spills > 10^3 bbl	30.6	29.2	13.2	15.4	28.9	23.9
Number of Sales						
Total	42	42	25	25	35	37
Atlantic Sales	6	6	4	4	6	6
Gulf of Mexico Sales	14	10	7	7	14	14
California Sales	5	5	3	3	5	5
Alaska Sales	16	16	7	7	19	11
Reoffering Sales	1	5	4	4	1	1
Value Estimates						
Net Economic Value ($ billion)	150	146	80	92	129	120
Net Social Value ($ billion)	147	144	79	90	127	119

*Conditional Mean Estimates of Resources to be Recovered

Table 15. Allocation of Developmental Benefits and Environmental Risks* (with compensation) by Alternative ($ Billions)

Region 1/	I-2 & I-2 Benefits	I-2 & I-2 Risks	II Benefits	II Risks	III-1 Benefits	III-1 Risks	III-2 Benefits	III-2 Risks	IV-1 & IV-2 Benefits	IV-1 & IV-2 Risks	V-1 & V-2 Benefits	V-1 & V-2 Risks
I	34.5	--	33.6	--	18.4	--	21.2	--	29.6	--	27.6	--
II	7.5	.1	7.3	.1	4.0	--	4.6	.1	6.5	.1	6.0	.1
III	4.5	.1	4.4	.1	2.4	.1	2.8	.1	3.9	.1	3.6	.1
IV	15.0	.1	14.6	.1	8.0	.1	9.2	.1	12.9	.1	12.0	.1
V	16.5	.8	16.1	.8	8.8	.4	10.1	.5	14.2	.7	13.2	.5
VI	21.0	.1	20.4	.1	11.2	--	12.9	--	18.1	.1	16.8	--
VII	3.0	.8	2.9	.8	1.6	.4	1.8	.4	2.8	.7	2.4	.3

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

* Benefits and environmental risks are rounded to nearest $.1 billion.

Table 16- 18(a)(3) Balancing Considerations

Planning Areas (in order of net social value)	Relative Environmental Sensitivity Ranking a/	Relative Marine Productivity Ranking a/	Alt. I #Sales	Alt. I Timing	Alt. II f/ #Sales	Alt. II f/ Timing	Alt. III i/ #Sales	Alt. III i/ Timing	Alt. IV #Sales	Alt. IV Timing	Alt. V #Sales	Alt. V Timing
Central Gulf of Mexico	ML	ML	6 b/	1982, 1983 1984, 1985 1986	10 b/	1982, 1983 1984, 1985 1986	7 b/	1982, 1983 1984, 1985	6 b/	1982, 1983 1984, 1985 1986	6 b/	1982, 1983 1984, 1985 1986
Western Gulf of Mexico	L	ML	4	1983, 1984 1985, 1986	b/		b/		4	1983, 1984 1985, 1986	4	1983, 1984 1985, 1986
North Atlantic	ML	MH	4 c/	1982, 1983 1984, 1986	4 c/	1982, 1983 1984, 1986	3 c/	1982, 1983 1984	4 c/	1982, 1983 1984, 1986	4 c/	1982, 1983 1984, 1986
Diapir Field	MH	L	3	1982, 1984 1986	3	1982, 1984 1986	1	1983	3	1982, 1984 1985	--	--
Southern California	ML	MH	3	1982, 1984 1986	3 g/	1982, 1984 1986	2 g/	1982, 1984	3	1982, 1984 1986	3	1982, 1984 1986
Navarin Basin	L	ML	2	1984, 1986	1	1983	1	1984	1	1985	2	1984, 1986
Eastern Gulf of Mexico	L	ML	4	1983, 1984 1985, 1986	b/		b/		4	1983, 1984 1985, 1986	4	1983, 1984 1985, 1986
South Atlantic	ML	ML	2 d/	1983, 1985	2 d/	1983, 1985	1	1984	2 d/	1983, 1985	2 d/	1983, 1985
Central & Northern California	MH	MH	2	1983, 1985	2 h/	1983, 1985	1 h/	1983	2	1983, 1985	2	1983, 1985
Barrow Arch	L	L	1	1985	1	1985	1	1985	1	1986	--	--
St. George Basin	H	H	3	1983, 1984 1986	3	1982, 1984 1986	1	1982	1	1986	2	1983, 1986
Gulf of Alaska	H	MH	1 e/	1985	1 e/	1986	--	--	1 e/	1984	1 e/	1985
Kodiak	MH	MH	1 e/	1985	1 e/	1986	--	--	1 e/	1984	1 e/	1985
North Aleutian Basin	MH	H	2	1983, 1985	2	1983, 1985	1	1983	--	--	2	1983, 1985
Norton Basin	H	ML	3	1982, 1984 1986	3	1982, 1984 1986	1	1982	2	1982, 1986	3	1982, 1984 1986
Cook Inlet	H	MH	1 e/	1985	1 e/	1986	--	--	1 e/	1984	1 e/	1985
Shumagin	H	MH	1 e/	1985	1 e/	1986	--	--	1 e/	1984	1 e/	1985
Hope Basin	L	L	1	1985	1	1985	1	1985	1	1986	--	--

Table 16 - 18(a)(3) Balancing Considerations

Footnotes

a/ Four rankings are given: H = Highest, NH = Next to Highest, NL = Next to Lowest, L = Lowest.

b/ Sales designated "Gulf of Mexico" are counted in the Central Gulf of Mexico planning area only.

c/ Includes Sale #76 - Mid-Atlantic, and, for alternatives I, II, IV, and V, sale #96 - Atlantic.

d/ Includes Sale #90 - Atlantic.

e/ Included in Sale #100 - South Alaska.

f/ Alternative II includes 5 reoffering sales (one per year), and a St. Matthew-Hall sales in 1985. Alternatives I, II, IV and V include 1 reoffering sale in 1982.

g/ Includes sale #80 and for alternatives I, II, IV and V, sale #95--both designated "California".

h/ Includes sale #73 and for Alternatives I, II, IV and V, sale #91--both designated "California".

i/ Schedule ends in 1985, includes slightly different planning areas, and includes 4 reoffering sales. This comparison shows sales only for the period of overlap with the other alternatives--that is, only for 1982-1985.

Table 17
Estimated Appropriations and Staff Requirements for Alternative 5-Year Leasing Programs

	FY 1982		FY 1983		FY 1984		FY 1985		FY 1986		FY 1987	
	$ mil.	FTE	$ mil.	FTE	$ mil.	FTE	$ mil.	FTE	$ mil.	FTE	$ mil.	FTE
Alternative I-1	125.6	1632	134.0	1648	167.4	1840	156.6	1871	151.5	1885	144.2	1846
Alternative I-2	125.6	1632	134.0	1648	161.1	1840	150.3	1871	144.2	1885	137.9	1846
Alternative II	125.9	1640	134.0	1652	184.6	1840	167.9	1871	162.1	1885	155.4	1671
Alternative III-1	126.0	1645	124.1	1608	135.0	1737	132.7	1734				
Alternative III-2	126.0	1645	124.1	1608	137.6	1737	135.3	1734				
Alternative IV-1	125.9	1640	129.0	1653	164.9	1834	155.9	1865	153.0	1880	146.3	1856
Alternative IV-2	125.9	1640	129.0	1653	159.1	1834	150.1	1865	147.2	1880	140.5	1856
Alternative V	125.9	1640	131.3	1653	163.5	1834	151.6	1865	148.1	1879	141.3	1850

B. Development of a Tentative Proposed Final Program

1. Results of Analysis

All the factors which must be considered under Section 18 have been analyzed on either a planning area or generic basis, some in quantitative terms when possible and others in qualitative terms. Consideration of many of these factors involves a degree of judgment which, in the selection of a leasing program, can only be appropriately applied by the Secretary since the factors do not lead to a definitive decision. This is because their quantification is uncertain and because they all do not lead in the same direction. As recognized by the Court of Appeals on October 6, 1981, the role of the Secretary of the Interior is to make a decision based on an "uneasy calculus."

For discussion purposes, an attempt has been made to select the timing and location of sales based primarily on the quantitative and non-subjective aspects of the Section 18 analysis. Since consideration of even these factors is by no means deterministic, many schedules could evolve and the one presented can only serve as an example.

General guidance on how one can apply the quantitative results of the comparative anaysis can be found in Part II.E. As discussed, the net social value calculations support the continued consideration of the 18 planning areas in the July 1981 proposed program.
The following timing guidelines would also be consistent with the values and rankings:

-- annual offerings in the Central and Western Gulf of Mexico;

-- biennial offerings in the North Atlantic, Diapir Field, Southern California, Navarin Basin, Eastern Gulf of Mexico, South Atlantic, Central and Northern California, and Barrow Arch; and

-- less frequent offerings in St. George Basin, Gulf of Alaska, Kodiak, North Aleutian Basin, Norton Basin, Cook Inlet, Shumagin, and Hope Basin.

Expressions of industry interest would argue in favor of biennial offerings in St. George Basin, Norton Basin, and North Aleutian Basin which would be a deviation from a schedule based solely on net social value rankings.

In developing a tentative proposed final program, these factors need to be considered together with certain guidance provided by the October 6, 1981, court order concerning the requirement to define leasing activity as "precisely as possible." Sales previously listed as "Atlantic" should be identified as one or the other of the two planning areas. Which particular one would be based on the appropriate pattern of leasing in each area. The state of preparedness in different OCS areas also needs to be considered. This factor affects plans for leasing in Central and Northern California where past delays in a decision on Area Identification preclude an early 1983 sale, a date which is supportable by the quantitative Section 18 analysis.

Sales in the first half of 1987 also need to be added to the schedule since the expected date of final approval for the program is July 1982 and the program is to cover the subsequent 5-year period. The sales proposed for this period should be consistent with the pattern of leasing in preceeding years.

2. Sample Program

Table 18 illustrates an example of the timing and location of sales in a program which would be consistent with the above discussion. Sale numbers conform with those in the July 1981 proposed program to the extent appropriate. This program has the following characteristics:

-- yearly sales in the Central and Western Gulf of Mexico;

-- biennial sales in the North Atlantic, Diapir Field, Southern California, Navarin Basin, Eastern Gulf of Mexico, South Atlantic, Central and Northern California, Norton Basin, St. George Basin, and North Aleutian Basin;

-- two sales in Barrow Arch;

-- adherence to the timing of sales in the July 1981 proposed program were consistent with the results of the section 18 analysis; and

-- timing of first sales reflects the Department's state of preparedness to hold them.

The following tables have been prepared for this schedule:

-- Table 19 shows statistical characteristics

-- Table 20 shows information relevant to § 18(a)(3) balancing considerations

Table 18
Sample Program

1982	
RS-2	
52	N. Atlantic
71	Diapir Field
69	Gulf of Mexico
57	Norton Basin
1983	
70	St. George Basin
76	Mid-Atlantic
75	N. Aleutian Basin
72	C. Gulf of Mexico
78	S. Atlantic
74	W. Gulf of Mexico
73	C & N California
79	E. Gulf of Mexico
1984	
80	S. California
82	N. Atlantic
83	Navarin Basin
81	C. Gulf of Mexico
87	Diapir Field
84	W. Gulf of Mexico
88	Norton Basin
89	St. George Basin
1985	
90	S. Atlantic
85	Barrow Arch
92	N. Aleutian Basin
98	C. Gulf of Mexico
102	W . Gulf of Mexico
91	C & N California
100	S. Alaska
94	E. Gulf of Mexico
1986	
95	S. California
96	N. Atlantic
107	Navarin Basin
104	C. Gulf of Mexico
97	Diapir Field
105	W. Gulf of Mexico
99	Norton Basin
101	St. George Basin
1987	
	S. Atlantic
	Barrow Arch
	C. Gulf of Mexico
	Hope Basin

Table 19
Statistical Characteristics of Sample Program

Number of Sales	
Total	41
Atlantic Sales	7
Gulf of Mexico Sales	12
California Sales	4
Alaska Sales	17
Reoffering Sales	1

Table 20. Section 18(a)(3) Balancing Considerations for Sample Program

Planning Areas (in order of net social value)	Relative Environmental Sensitivity a/	Relative Marine Productivity a/	# Sales	Timing
Central Gulf of Mexico	NL	NL	6 b/	1982, 1983, 1984, 1985, 1986, 1987
Western Gulf of Mexico	L	NL	4	1983, 1984, 1985, 1986
North Atlantic	NL	NH	4 c/	1982, 1983, 1984, 1986
Diapir Field	NH	L	3	1982, 1984, 1986
Southern California	NL	NH	2	1984, 1986,
Navarin Basin	L	NL	2	1984, 1986
Eastern Gulf of Mexico	L	NL	2	1983, 1985
South Atlantic	NL	NL	3	1983, 1985, 1987
Central and Northern California	NH	NH	2	1984, 1986
Barrow Arch	L	L	2	1985, 1987
St. George Basin	H	H	3	1983, 1984, 1986
Gulf of Alaska	H	NH	1 d/	1985
Kodiak	NH	NH	1 d/	1985
North Aleutian Basin	NH	H	2	1983, 1985
Norton Basin	H	NL	3	1982, 1984, 1986
Cook Inlet	H	NH	1 d/	1985
Shumagin	H	NH	1 d/	1985
Hope Basin	L	L	1	1987

a/Four rankings are given; H - Highest, NH - Next to Highest NL - Next to Lowest, L - Lowest
b/Sale 69 - Gulf of Mexico is counted as a Central Gulf of Mexico sale.
c/Includes sale #76 - Mid-Atlantic.
d/Included in sale #100 - South Alaska.

IV. Technical Adjustments to the Program

A. Changes to Planning Area Boundaries

BLM, GS and MMS recommend that the planning area boundaries published in the Federal Register on July 31, 1981, be changed as follows:

1. Atlantic

The boundary line between the North and South Atlantic should be moved from Cape Charles, Virginia, (along the southern border of Official Protraction Diagram (OPD) (NJ 18-8), to Cape Hatteras, North Carolina, (along the southern border of OPD NI 18-2). This change would correspond to the geologically most appropriate division of the planning areas. It involves the following acreage changes:

From:	Cape Charles, Virginia, boundary line	
	North Atlantic	110.8 million acres
	South Atlantic	127.5 million acres
	Total Atlantic	238.3 million acres
To:	Cape Hatteras, North Carolina, boundary line	
	North Atlantic	139.2 million acres
	South Atlantic	99.1 million acres
	Total Atlantic	238.3 million acres

2. California

The boundary line for the California planning areas should be moved so as to conform to the borders of OPD's which correspond approximately to the 3,000 meter isobath. The Central and Northern California/Southern California dividing line would remain at Point Conception. The southernmost boundary of the Southern California planning area coincides with the U.S. - Mexico international boundary.

The acreage included within the previous boundary was 57 million acres. The area enclosed within the revised boundary consists of the following:

Central & Northern California	36.6 million acres
Southern California	22.5 million acres
Total California	59.1 milion acres

3. Alaska

To better delineate areas of oil and gas potential, the boundary between the Barrow Arch and Hope Basin planning areas should be redrawn at Point Hope rather than along 69 degrees N. latitude. For the same reason, the southern boundary of the Cook Inlet area should extend along the 57 degree N. latitude line between OPD's NO 4-6 and NO 4-8.

In order not to divide OPD's unnecessarily, the boundary between Kodiak and Gulf of Alaska should run along the 147 degree longitude line between OPD's NO 6-5 and NO 6-6, between OPD's NO 6-7 and NO 6-8, and between OPD's NN 6-1 and NN 6-2. In order to conform to the Canadian boundary line, the southern boundary of the Gulf of Alaska area bisects OPD's NN 7-3, NN 7-4, NN 8-3 and NN 8-4.

B. Timing Changes

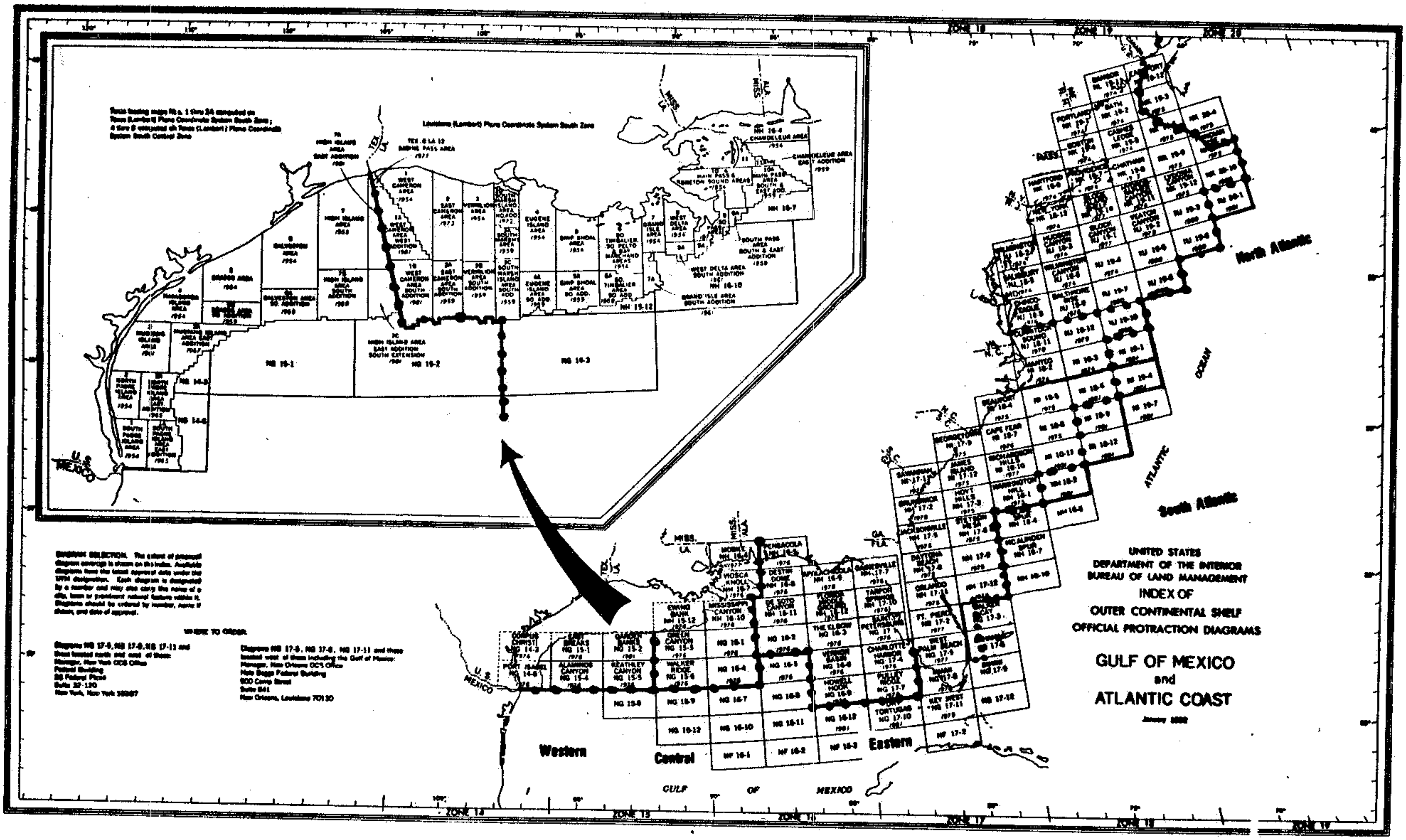
1. RS-2 must be delayed 1 month (from June to July 1982) due to delay in a decision on the proposed Notice of Sale.

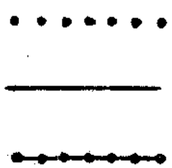
2. #73 - Central and Northern California must be delayed 8 months (from January to September 1983) due to delay in a decision on Area Identification.

C. Location Changes

#90 and #96 - Atlantic are changed to South Atlantic and North Atlantic respectively, in response to the D.C. Circuit Court of Appeals decision.

Figure 2 Atlantic and Gulf of Mexico Planning Areas





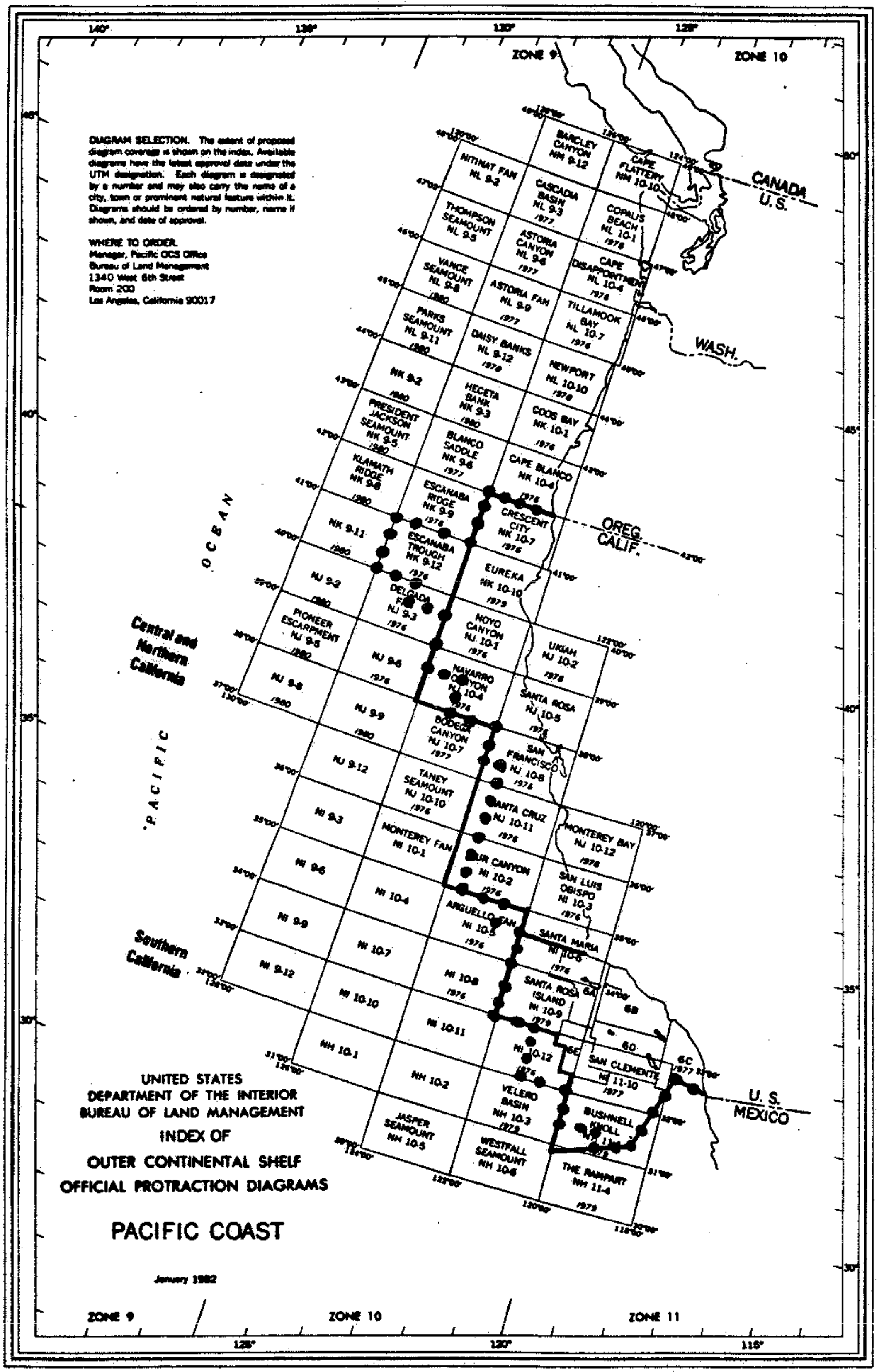
July 1981 planning area boundary

proposed boundary adjustment

boundary unchanged from July 1981 boundary

Figure 3

California Planning Areas



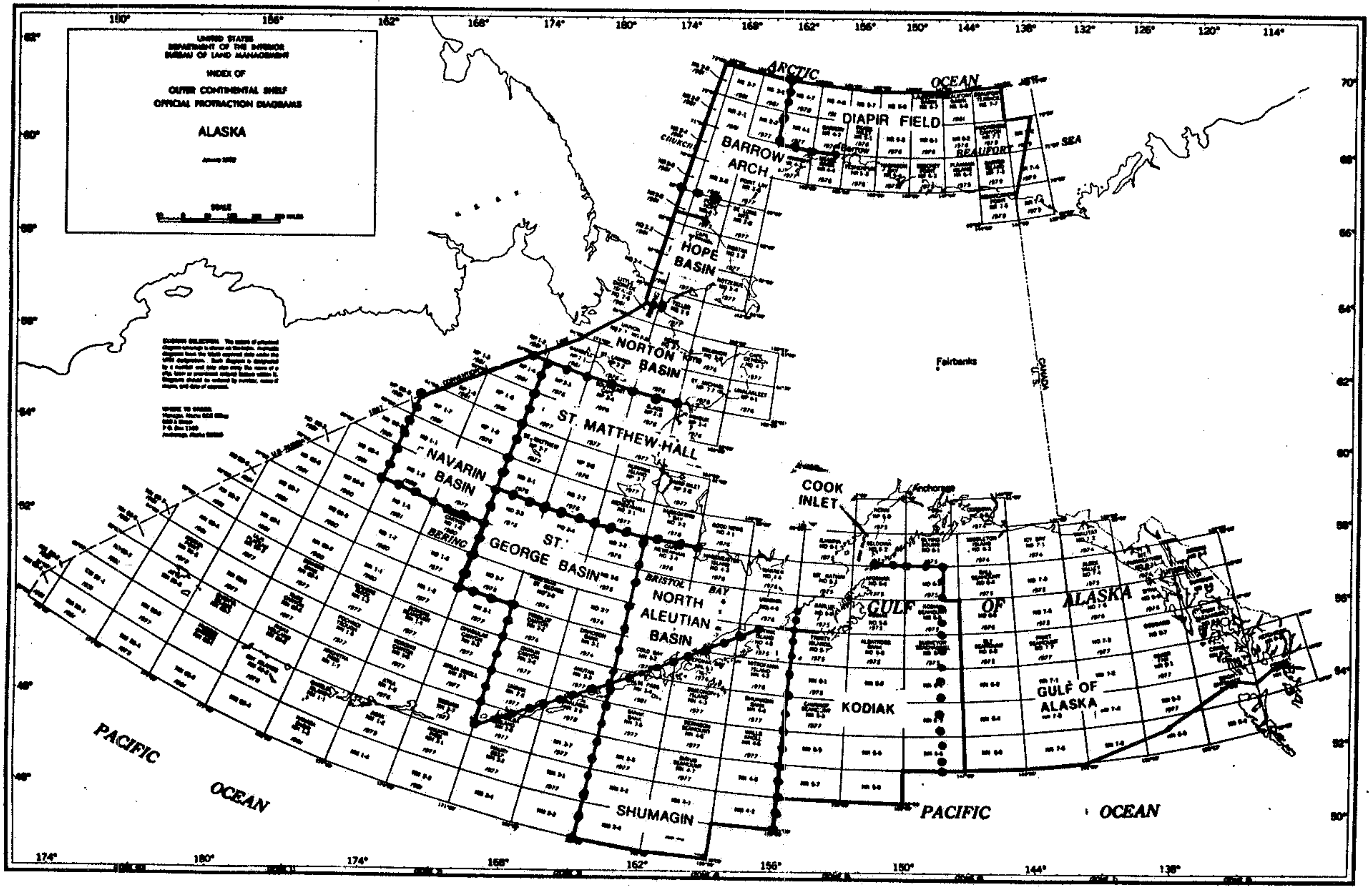
• • • • • • • July 1981 planning area boundary

——————— proposed boundary adjustment

—•—•—•—•— boundary unchanged from July boundary

Figure 4

Alaska Planning Areas



July 1981 planning area boundary

proposed boundary adjustment

boundary unchanged from July boundary

APPENDIX 1

Laws, Goals, and Policies of Affected States
[Sec. 18(a)(2)(F)]

On December 22, 1980, the Under Secretary of the Interior wrote to the Governors of affected States requesting their comments on the possible revision or reapproval of the 5-Year OCS Oil and Gas Leasing Program. These letters specifically requested the Governor to identify any laws, goals and policies of his State which relate to the decision to plan for a lease sale off the State's shore. Also requested was the status of any coastal zone management program being developed or administered by the State and the extent to which the Governor believed completed programs would affect OCS planning.

Eighteen of the 23 affected States responded to this request. These responses were provided to the Secretary as part of the annual review of the 5-year program. A detailed summary of them was also included as an attachment to the decision material provided to the Secretary in connection with preparation of the April 1981 draft proposed program. Comments from affected States on the draft proposed program provided no new information on specific laws, goals, or policies. Comments on the proposed program are summarized in Appendix 6.

The following chart lists the States which responded to the December 22, 1980, request and the laws, goals or policies specifically identified by the Governor as relevant matters for the Secretary's consideration. A number of States simply cited their Coastal Management Program. These programs were reviewed and a determination was made that they contain no goals or policies that would pose irresolvable conflicts with planning for a lease sale. Specific portions of a State Coastal Management Program cited in a Governor's letter are included on the chart. Chapter 1 of the Final SEIS discusses the status of the coastal zone management plans of the affected States.

State	Law, Goal, or Policy Identified
Maine	Coastal Zone Management Program
New Hampshire	Proposed Coastal Zone Management Program and draft coastal zone management legislation 1/
Massachusetts	None
Connecticut	Coastal Management Program
New York	None
Pennsylvania	Coastal Zone Management Program commits State to provide opportunities for storage, transfer and refinery facilities in the Delaware Estuary coastal zone.
Delaware	Coastal Management Program Section 5.D.3. - generally supports OCS development facilities; Appendix E and F - consistency determination required for exploration and development.
Maryland	Referred to material previously submitted to the Department, including the Coastal Management Program.
Virginia	State coastal resource management process 2/
North Carolina	Referred to December 1978 submission from State, especially North Carolina Coastal Plan, Chapter 3, pages 133-163, which lists State policies concerning coastal management in North Carolina. Pages 151-152 list State policies concerning the OCS. These include: (1) State support for an approach to offshore oil and gas exploration which will provide an adequate supply of energy while protecting the public environmental, social and economic interests in the State's coastal and offshore areas; (2) commitment to the State's taking an active role in the OCS decision process; (3) establishment of certain State regulations; (4) assertion of State authority over State lands; and (5) oil discharge control policy.
South Carolina	1. South Carolina Oil and Gas Act (Act #179), which regulates the exploration for, filling for, transportation of and production of oil and gas and their products and provides penalties for violations.

2. Capacity Use Law, which provides for regulations to control any activity which could affect ground water, including drilling.

3. South Carolina Pollution Control Act, which governs air and water pollution.

4. Finding of the General Assembly that the highest and best use of the seacoast of the State is as a source of public and private recreation. The preservation of this use is a matter of the highest urgency and priority, and that such use can only be served effectively by maintaining the coastal waters, estuaries, tidal flats, beaches, and public lands adjoining the seacoast in as close to pristine condition as possible, taking into account multiple use accommodations necessary to provide the broadest possible promotion of public and private interests.

5. South Carolina - Safety Act of 1970, Public Service Commission - Section 58-3-10 et seg. - South Carolina Code of Laws

The Public Service Commission has economic and safety jurisdiction over all investor-owned intrastate natural gas systems, and safety jurisdiction over all intrastate natural gas systems.

6. South Carolina Coastal Management Plan and Policy and South Carolina Coastal Zone Management Act of 1977, which describes the policy of the State, including to protect the quality of the coastal environment and to promote the economic and social improvement of the coastal zone and of all the people of the State. The management plan contains numerous regulations and policy statements which are or may be applicable to OCS leasing decisions, such as policies and regulations governing dredging, public services and facilities, energy and energy related facilities and transportation. The plan lists geographical areas of particular concern and cities energy facility planning, erosion control, beach and shoreline access and living marine resources as special management areas. According to the State, the program will affect OCS lease sales, exploration, development and production activities through its Federal consistency provisions. The South Carolina Coastal Council is required to review Federal actions within the State program and has direct

	permitting authority over actions which affect critical areas (coastal waters, tidelands, beaches and primary ocean-front sand dunes) such as pipeline construction. The Coastal Council must also review and approve permits granted by other State agencies for activities within the coastal zone but not in critical areas thereof.
Florida	None
Alabama	5-year program not inconsistent or in conflict with any State laws or regulations, including Coastal Management Plan.
Louisiana	Coastal Management Program emphasizes protection of barrier islands and coastlines, resources that are directly impacted by offshore development.
Texas	None
California	State policy that OCS development should occur only where resource is sufficient to justify pipeline transportation. Section 30260 of California Coastal Act allows State to require the least environmentally damaging feasible alternative transportation system be used.
Washington	Energy facility construction requires review by the Energy Facility Site Evaluation Council. Washington Shoreline Management Act of 1971 requires preparation of local shoreline master programs, which together make up the State coastal zone program. CZM consistency required for OCS activities.
Alaska	<u>State policies:</u> 1. Areas adjacent to producing oil fields should be leased first to minimize need for new facilities and new capital expenditures and to minimize disruption of new areas. Progress outward from these areas. 2. Impacts of oil development on fish and wildlife resources and on industries that depend on these resources should be considered. 3. Areas of "low physical hazard rating" should be leased first, to minimize the chances of oil spills. 4. Areas of lowest biological productivity, vulnerability and diversity and of least commercial, subsistence and recreational use should be leased first.

5. Lease only areas where existing oil spill containment and cleanup technology is adequate to handle maximum project spill.

6. Do not lease areas which are critical habitat for any species of major economic or subsistence importance to Alaskans until mitigating measures are adopted to resolve existing resource conflicts.

7. Consider resource values and uses of adjacent lands in evaluating suitability of Federal lands for leasing.

Coastal Management Program:

State believes final Notice of Sale should be subject to official State consistency ruling.
Timetable of local coastal programs in areas where an adjacent OCS lease sale is scheduled. (Note that program completion dates are estimates only.)

CRSA	Program Completion Date	Sale and Date	
North Slope Bor.	late '82	Barrow Arch	2/85
		Diapir Field	9/82
NANA	early '83	Hope Basin	7/85
Bering Straits	fall '83	Norton	11/82
City of Nome	early '81	Norton	11/82
Yukon-Kuskokwim	early '83	Norton	11/82
		Navarin	3/84
		N. Aleutian Shelf	4/83
Bristol Bay	late '83	N. Aleutian Shelf	4/83
Bristol Bay Bor.	early '82	N. Aleutian Shelf	4/83
Aleutian/Pribilof Island	mid '83	St. George	2/83
		N. Aleutian Shelf	4/83
Kodiak Is. Bor.	late '82	S. Alaska	10/85
Kenai Peninsula Bor.	late '81	Cook Inlet	9/81
		S. Alaska	10/85

Incorporate "local readiness" to handle impacts of the actual phase of OCS activity in question into the Federal decisionmaking process--i.e., pre-sale: existence of local planning capacity with adequate sources of funding to prepare for exploration impacts, if any tracts are leased by industry.

State has tried to coordinate their lease sale schedule with Federal schedule for off- and onshore lease sales.

Notes

1. A significantly revised proposed CZM program for New Hampshire was published January 18, 1982. The draft legislation was not passed by the State legislature.

2. Virginia, while not eligible for participation in the Federal coastal zone mangement program, does have a State coastal zone management plan. The goals of this plan include encouragement of exploration and production of Outer Continental Shelf energy reserves, extraction of mineral resources in an environmentally sound manner, prevention of environmental pollution and protection of public health, prevention of damage to natural resources, etc.

APPENDIX 2

Appendix 2

The 5-Year OCS Leasing Program: Economic Considerations

Table of Contents

Appendix 2

The 5-Year OCS Leasing Program: Economic Considerations

Economic Objectives and Benefits

The OCS Lands Act as amended establishes several purposes and policies from which the economic objectives of the OCS Leasing Program can be derived. Sec. 18(a) requires the Secretary to prepare and maintain a 5-year Leasing Program consisting of a schedule of lease sales "which he determines will best meet national energy needs . . ." Elsewhere the Act calls for expedited exploration and development of the OCS to achieve national economic and energy policy goals, among other purposes. The National Energy Policy Plan published in July 1981 by the Department of Energy calls for public policies that will bring the resources of the OCS and other Federal lands into the market place. It is thus useful to explore the ways in which OCS oil and gas development contributes to meeting national economic goals and energy needs so that these purposes can be reflected in the development of the 5-Year Leasing Program.

The national energy situation is clear. The U. S. is currently importing substantial quantities of oil at prices determined, in large part, by the OPEC cartel (currently around $35 per barrel). These prices are much higher, even in real terms, than the price of oil prior to 1973. Elaborate and costly efforts are being undertaken in hopes of avoiding the damaging effects of these costly imports on the level and growth of incomes in the U. S. However, it is apparent that none of these efforts, individually or in sum, will reduce the demand for oil or increase alternative supplies sufficiently to free us from the need to continue importing oil for much if not all of the next half century.

Against this background, the oil and gas resources of the OCS can be viewed as a far less costly source of oil and gas supplies. While OCS production will probably not be sufficient to alter the world price of oil, any savings that result from finding and producing OCS oil and gas instead of buying additional imports at the OPEC price contribute directly to our efforts to maintain the level and growth of U. S. incomes in the face of the increased real cost of a substantial portion of our energy supply.

The savings can be quite significant. If it costs $25 per barrel on average to find and produce OCS oil and gas, then the economic benefits to the nation if the OPEC price is $35 per barrel are $10 per barrel. Under these conditions, the undiscovered producible oil and gas resources of the OCS represent a source of income totaling roughly one half trillion dollars. In an economy suffering from inflation and loss of productivity, due in fair part to the high cost of imported oil, it is essential to manage these OCS oil and gas resources in a manner that yields the greatest possible contribution to national income and thus aids economic recovery. Steps to delay or reduce OCS production thus hinder economic recovery and should not be taken unless they result in other gains to society which exceed the economic costs of delay or reduction.

This potential income from leasing and developing OCS oil and gas can be realized directly in the form of Federal lease revenues which can be used to pay for government services instead of using taxes. Dividends to stockholders and tax payments from the profits earned by lessees also contribute. Benefits are also realized by reductions in the costs of maintaining a strategic reserve of oil to protect against the economic consequences of disruptions in imports. Production of OCS oil and gas will also contribute to reduction in the balance of trade deficit and its resulting downward pressures on the dollar in world markets and inflation at home. The magnitude of these effects is in proportion to the dollar savings achieved by producing OCS oil rather than importing more from abroad.

A further benefit can result if OCS exploration and development can reduce pressures to adopt even more costly measures to reduce imports. Many government regulations, tax policies, and subsidies designed to suppress demand or bring forth alternative supplies cost more per barrel of oil or oil equivalent than OCS production. There is some evidence that some alternatives may be even more costly than imported oil although the unquantifiable cost to national security of imports should be considered here. When such costly alternatives involve excessive expenditures of capital, labor and natural or environmental resources in efforts to reduce imports of oil, they mean the production of less income for the American people. Any contribution that OCS oil and gas production can make to avoiding such excessive expenditures means more income. OCS oil at $20 or $25 is clearly preferable economically to synthetic oil costing much more than this.

In summary, the economic objective of the OCS oil and gas program is to lease the rights to these resources in a manner that results in the maximum contribution to future incomes in the United States. In general, this can be achieved by allowing production of as much oil and gas as can be found and produced at costs per barrel less than the alternative sources. It is important to recognize that in examining the ways in which a 5-Year Leasing Program can achieve these benefits, many other factors need to be considered. The OCS Lands Act requires consideration of many non-economic factors, particularly environmental risks and costs and impacts on coastal communities. These considerations are discussed elsewhere in the 5-year program planning process and are not addressed here.

The rate, timing and location of lease sales can also affect the public benefits. In particular, the achievement and distribution of benefits depend on how rapidly leases are offered for sale and issued, and on the subsequent rate of investment in exploration, the resulting discoveries and the resources produced in the various regions of the OCS. The remainder of this paper will address these relationships and describe the economic analysis used to provide the economic information considered by the Secretary of the Interior in formulating and approving the 5-Year Leasing Program.

Measurement of Benefits

The economic benefits from the development of OCS oil and gas are best measured by the net economic value of production. The net economic value of a field or reservoir is the sum of the revenues from oil and gas produced less the sum of the costs of finding the resource, producing it and transporting it to market. The measure of net economic value as revenues less costs is identical to the measure of value as the sum of bonuses and royalties paid for leases, plus tax revenues and after-tax corporate profits. These are merely the forms in which the net economic value is distributed through the economic system.

The U.S. Court of Appeals, D.C. Circuit, noted in California v. Watt that DOE defined net economic value as industry profits, Federal tax revenues and royalty payments while DOI's Leasing Program defined it as the difference between the OPEC price and the costs of production. In fact, DOE used "after tax net present value" rather than industry profits. This is the sum of the bonus payments and the profits expected after taxes and royalties are paid. As the explanation above shows, the DOE and DOI definitions are equivalent rather than inconsistent.

Because the timing of costs and production is directly linked to the rate of leasing, it is useful to consider the way in which timing influences OCS benefits. In general, it is socially valuable to realize income as early as possible and to incur costs as late as possible. This results from people's strong preferences for consumption of goods and services in the present rather than the future and from the additional income that can be produced by investing sooner rather than later. This time value of money and resources is reflected in the interest rate — i.e., the return that can be earned by investment of resources that are available in the present to produce increased future consumption. One is willing to forego present consumption only if the resulting investment results in more consumption in the future than is foregone in the present. For example, one invests at 10% return rather than spending current income because each dollar of current expenditure foregone can provide $1.10 in a year or $1.61 in 5 years. On the other hand, one would trade one dollar of income 5 years in the future for 62 cents of present income if one could invest the 62 cents at 10% or more. (The investment of 62 cents at 10% would yield one dollar in 5 years.)

Similar considerations are involved in decisions about the rate of natural resource development. If resources "earn" about 10% in our economy, the social value of a resource development can be increased 1.61 times if the same benefits can be made to occur 5 years earlier. On the other hand, a delay of 5 years reduces the social value of the benefit by 38%. The social value or "present value" of a benefit (or a cost for that matter) is thus calculated by discounting its future value at the appropriate annual rate.

Of course, since the benefits of oil and gas development are production revenues less costs, benefits will increase over time if oil and gas prices are increasing at a greater rate than costs. It is important to note, however, that the net economic value does not, in general, increase at the same rate as real (that is, inflation adjusted) oil and gas prices. For resources that are relatively low in cost, the net economic value will be relatively large and a given percentage price increase will result in a relatively low percentage increase in benefits. In contrast, resources that are relatively high in cost will have relatively low net economic value which will increase at a relatively high percentage rate as a result of a given percentage price increase.

Assuming for the moment that oil and gas resources are "on deposit" in the earth, the decision whether to produce them now or "leave them in the bank" must reflect our expectations about whether the net economic value in the future will have increased enough to offset the losses in social value that would result from realizing that value at a later time. Will the benefits from production earn more in the bank or in use, producing more income? If future benefits are "discounted" at 8% (the discount rate currently used in evaluating government programs) to reflect our time preferences and investment opportunities, then the gain in net economic value from "leaving oil in the bank" must be at least 8% annually to offset the losses that result from foregoing income from production in the present.

It is clear from these concepts that from the economic perspective, it is worthwhile finding and producing any OCS oil and gas that is sufficiently less costly than OPEC oil that its net economic value increases at rates less than the 8% discount rate under expected oil price increases. Otherwise "banking" oil in the ground will deprive the American people of present consumption and investment without sufficient future gains to offset the income they would forego.

Because the OCS is not a bank of uniform and known deposits of oil and gas, it is important to consider how the variability and uncertainty that is characteristic of OCS resources affects the way public benefits are realized. Not only is there great variation in the size of OCS oil and gas deposits, but the costs of finding and producing oil and gas also vary significantly from region to region. Because of the substantial fixed investment needed to undertake production, the costs per barrel of producing oil and gas depend greatly on the size of the reservoir. In OCS areas with high costs, only the larger reservoirs will have costs per barrel less than the current price of oil. There are likely to be many smaller reservoirs which are not economical to produce and do not provide public benefits at current or expected prices of oil. These will become economical and yield benefits if oil prices increase faster than costs.

Of the reservoirs that are economical at expected price levels, some will have net economic values so small that expected price increases make it worthwhile to postpone their development. Other economical reservoirs will have sufficiently high net economic value to make the gains from expected oil price increases insufficient to offset the decrease in present value caused by any postponement.

Table 1 shows the effects of discounting both the future value and the cost of a barrel of oil by the 8% discount rate while increasing the real (inflation adjusted) price of oil by a 1% or 2% annual rate. In the first row we find that the revenues from a barrel of oil which are \$35 in 1982 will be \$39.10 in 1993 if oil prices rise by 1% or \$43.60 if they rise by 2%. However, when we discount the value of this oil at a rate of 8% per year (pursuant to OMB guidelines) we find that the "present value" of that 1993 barrel is only \$16.20 at 1% and \$18.10 at 2%.

To measure the net present value we must consider the costs as well as the revenues. In example 1 the costs are \$23 dollars per barrel. Note that the resulting net economic value in 1982 is \$12 while the net present value from production in 1993 is \$6.60 if oil prices rise by 1% and \$8.50 if they rise by 2%. This indicates two things. First, the nation clearly prefers to produce this resource in 1982 rather than 1993 even if real oil prices are expected to increase at 2% per year. Second, there is a measurable present value loss associated with a decision to produce in 1993 rather than 1982. If oil prices increase at 1% this cost is \$5.40 per barrel; at 2%, the cost is \$3.50 per barrel. This can be seen as the cost of delaying production from 1982 to 1993.

In example 2, however, with higher costs of \$33 per barrel and lower net economic value, there is a gain in net present value from delaying production. This occurs because an annual price increase of 1% or 2% causes an increase in net economic value that exceeds the 8% discount rate, at least for some time. If prices increase at 1%, delaying production from 1982 to 1987 increases the net present value by \$0.60 per barrel. Note that the net present value stays

Table I

Effect of Price Increases on Net Present Value
of Production at Different Times

	Year of Production													
	82	83	84	85	86	87	88	89	90	91	92	93	94	95
Revenues ($/BBL) with oil prices increasing														
at 1%	35.0	35.4	35.7	36.1	36.4	36.8	37.2	37.5	37.8	38.3	38.6	39.1	39.4	39.9
at 2%	35.0	35.7	36.4	37.2	37.9	38.7	39.5	40.3	41.1	41.9	42.7	43.6	44.5	45.4
Present value of revenues ($/BBL) at 8% discount rate (1%)	35.0	32.7	30.4	28.4	26.4	24.7	23.0	21.4	19.9	18.6	17.3	16.2	15.1	14.1
(2%)	35.0	33.0	31.0	29.3	27.5	25.9	24.4	23.0	21.7	20.4	19.2	18.1	17.0	16.0
Example 1: Present value of costs ($/BBL) at 8% discount rate	23.0	21.2	19.6	18.1	16.7	15.4	14.2	13.1	12.1	11.2	10.3	9.6	8.8	8.1
Net present value ($/BBL) (1%)	12.0	11.3	10.8	10.3	9.7	9.3	8.8	8.3	7.8	7.4	7.0	6.6	6.3	6.0
(2%)	12.0	11.8	11.4	11.2	10.8	10.5	10.2	9.9	9.6	9.2	8.9	8.5	8.2	7.9
Example 2: Present value of costs ($/BBL) at 8% discount rate	33.0	30.5	28.1	26.0	24.0	22.1	20.4	18.8	17.4	16.1	14.8	13.7	12.6	11.7
Net present value ($/BBL) (1%)	2.0	2.2	2.3	2.4	2.4	2.6	2.6	2.6	2.5	2.5	2.5	2.5	2.5	2.4
(2%)	2.0	2.5	2.9	3.3	3.5	3.8	4.0	4.2	4.3	4.3	4.4	4.4	4.4	4.3

level or declines after 1987, which is thus the optimum year for production of resources costing $33 per barrel if 1% price increases are expected. However, at 2% increase, production yields the greatest value in 1992. Similar calculations assuming a price increase of 3% annually show that oil costing $23 per barrel is optimum to produce in 1984 while oil costing $33 per barrel becomes optimum in 1996. In fact however, oil costing $33 per barrel to produce would not be economical for a lessee to produce under the minimum royalty of 1/8 which would add another $4.38 to the producer's cost when oil is $35 per barrel.

Clearly, the difference between estimating the present value loss associated with the delay in producing a single barrel and the cost of delaying production in an entire reservoir or region is only a matter of degree. The only additional calculation necessary is to multiply by an estimate of resources involved. If, for example, one wished to calculate the present value loss from delaying 10 million barrels of production costing $23 per barrel from 1982 to 1993 at a 1% annual price increase, the cost would be $54 million. These calculations show the relationship between the benefits to the economy, the costs, the price of oil and its rate of increase, and the timing of production. Before using these relationships to estimate the net economic value of the resources in various OCS areas and the net present value of specific sales and leasing programs, it is worthwhile examining the effects of leasing at different rates.

In conclusion, it is possible to restate the economic objective of the OCS program in a way that allows more precise estimation of the benefits that result. Meeting the nation's economic and energy needs can be translated into the objective of finding and producing those reservoirs which, given current OPEC prices and expectations about future prices, and given the costs of exploration and development, have a net present value that decreases if their development is postponed. Any such reservoirs that are not found and produced represent decreased benefits to the nation's economy.

National Benefits and the Rate of Leasing

The national benefits of the OCS program depend on the amount, the costs, and the timing of oil and gas production. In general, the faster leases are made available by the government over the next 5 years, the more production will result over the subsequent 20 to 30 years. In addition, benefits will be higher if the lower cost resources are found and produced first. These two factors are relatively easy to understand and to estimate. However, it also is important to establish the link between the rate and sequence of leasing on one hand and the timing of the benefits that can be expected on the other. In the U.S. economy in general and the OCS Program in particular, the timing of oil and gas production is determined by many individual investment decisions made by numerous firms. Substantial investments are needed on the OCS to locate oil and gas reservoirs that are hidden beneath the ocean in the earth's crust. Additional investments are needed to install production and transportation systems to extract and bring to market the oil and gas that is found. As shown by the examples in Table 1, there is a time at which these investments will yield the maximum benefit for the nation, a time which differs from reservoir to reservoir.

For many reservoirs yet to be discovered, the optimal time for investment in exploration has already past. Even under expected future price increases, the benefits from these reservoirs will decrease as each year passes without their being developed. For other reservoirs, the optimal time is within the next 5 or 6 years. For still others, the optimal time for investment is years, in some cases decades, away. Some of these reservoirs are not economical at today's prices and costs. Others are barely economical, but their net present value will be increasing for many years to come.

Because of the rapid increases in oil prices during the 1970's, many reservoirs whose benefits to the country would not have reached their maximum until late in this century have been shifted into the first category. They are already past ripe and their benefits decrease with each passing day. Clearly the rate and sequence of OCS lease sales must seek to assure that investments are made to harvest quickly this crop of opportunities. Rapid oil price increases have also moved many undiscovered reservoirs into the category that will ripen within the next 5 or 6 years. The leasing program should clearly facilitate the investments that will reap these fruits as they reach their prime. For the third category, however, investments should not occur for some time.

The payoffs firms reap from their investments in acquiring leases and drilling exploratory wells are influenced by price expectations and costs in the same way as the national benefits. Firms make higher returns from investing at the optimal time. For this reason, firms have an incentive to anticipate future prices and choose their investments carefully. In fact, the lease market and the rate of investment in exploration are constantly adjusting as firms alter their expectations of future prices. This means that it is not necessary for the 5 Year Leasing Program to be tied precisely to an accurate forecast of future prices and costs. It is true that estimates of net economic value will change depending on the price and cost estimates used. However, within the foreseeable range of future prices and costs, these changes are not likely to alter the fundamental task of the program at present. This task is to facilitate an efficient allocation of investments by firms in the wide variety of prospects found on the OCS by making a wide range of opportunities available for leasing. If leases are made available at a time later than the optimum, firms will not be able to invest in ways that yield the greatest benefit to the nation's economy. Thus it is important to the benefits of the program for OCS areas to be opened and for leases to be made available at a rate fast enough to assure that industry can invest whenever it sees the greatest payoff.

From this discussion, it is clear that an OCS leasing program could make leases available too slowly:

- if some areas of the OCS were not made available as soon as some prospects in those areas had reached their optimal time for investment in exploration; or

- if the tracts made available in areas being offered did not include all of the prospects which had reached or were about to reach their optimum time for investment in exploration.

While the oil and gas in these prospects would eventually be found even under a slower leasing rate, the delay in its production caused by not making them available at the proper time causes a loss in value to the economy.

While it is clearly possible to offer leases too slowly, concerns have been raised that it is also possible to offer leases too rapidly or too soon. Certainly, if investments in exploration and development are made to bring oil and gas reservoirs into production before they have reached their maximum net present value, the economy will suffer in the long run. It could also suffer if the costs of exploration and development were increased by the rate of activity that results from faster leasing. But this loss in economic benefits would only occur if the increase in costs were not more than offset by the increased present value that results from having production occur sooner. Firms are not likely to incur such costs unless they are justified by higher returns.

It is also possible, of course, that at least some firms will make mistakes in their OCS investments which would be avoided, or at least postponed, by leasing more slowly. Firms may err in their estimates of future prices or in their assessment of the extent or cost of the resource in a given prospect. It is unlikely, however, that a restricted leasing program could systematically prevent such errors without substantially delaying production of resources that are at their optimal time.

Investments in exploration often result in discovery of resources that are not yet economical or that are still growing in net present value. Non-commercial discoveries are properly relinquished and can be leased in future decades when prices have risen enough to make their development profitable and beneficial to the economy.

The development of marginal commercial discoveries whose net present value is still growing under expected prices increases is properly postponed by the leaseholders until returns are optimum . Such economic behavior is often denounced as speculation despite the additional national benefit it generates. Diligence requirements, on the other hand, can cause a firm to develop such reservoirs prematurely because that is more profitable to the firm than relinquishing them entirely.

However, it seems unlikely at this point that the costs of leasing too fast or too soon will be significant. Premature development can only occur on low value tracts when expected price increases are relatively high. Of all the prospects available for investment, this is a relatively small set. In addition, firms tend to prefer to invest in higher value tracts. This would limit the leasing of tracts that could be developed prematurely. Furthermore, use of a higher minimum submissible bid would tend to prevent the leasing of such tracts even though they are offered.

Royalties would also tend to reduce the leasing of low net economic value tracts. In order to receive a bid, the net economic value must exceed the minimum bid amount by the expected royalty payments. Royalties also tend to counteract the tendency of diligence requirements to cause premature development of low value tracts. Royalties cause the firm's profits to be less than the net economic value. This means that profits grow faster than net economic value at a given rate of price increase which makes the optimal time for a firm to develop a tract occur later than the optimal time from the national perspective Thus firms will tend to delay development of marginal tracts if price increases are expected rather than develop them prematurely.

Because of the variation in the economic value of tracts even within OCS areas, it is not possible to identify tracts that could be prematurely developed during formulation of the leasing program. Nor is it possible to set a leasing rate that would prevent premature investment without incurring delay costs. In general then, the economic guideline to follow in formulating the 5-Year OCS Leasing Program is to assume that, by and large, offshore firms would be able to identify correctly from all of the investment opportunities available under a given program, those that have the highest net present value and profit. They would then be able to channel investments to these prospects at the proper time. Leasing should proceed at a faster pace in areas with higher average net economic value because there are more prospects in such areas that are at or past their optimum time of development. Conversely, leasing should proceed at a slower pace in areas with lower average net economic value because a greater proportion of prospects in such areas are still years from their optimum.

These principles were followed in estimating the potential benefits from development in different areas of the OCS and in estimating the net economic value of various sales and alternative leasing programs considered in the process. Estimates of the economic benefits from OCS oil and gas development were based on the amounts of resource expected to be discovered, the costs of exploration, development and production, and the timing of production. These estimates are described in the next sections.

Estimation of Net Economic Value by OCS Planning Areas

The net economic value associated with each OCS planning area is the product of estimates about the expected amount of resources and the estimated net economic value per barrel of oil equivalent in each planning area. Notationally, this can be represented as follows;

$$NEV_i = ER_i \times V_i$$

where NEV_i = net economic value for OCS region i

ER_i = the expected amount of oil and gas in barrels or equivalent in region i

V_i = net economic value per barrel for region i.

Expected Resources

Table 2 presents the ranking of OCS regions by estimated conditional resource. Conditional resource estimates are those quantities of oil and gas which are estimated to be present if the particular basin contains hydrocarbons. These estimates were provided by the U. S. Geological Survey and are based on estimates produced by the Resource Appraisal Group. The quantities of gas in trillion cubic feet (TCF) are converted to oil equivalence (in billion barrels) using the factor 5.62. This reflects the fact that there is, on average, the energy equivalent of 5,620 cubic feet of natural gas in every barrel of oil. The conditional estimate of the potential of the province is based upon the geology of the areas and theories of hydrocarbon accumulation.

Before this resource estimate is used it is adjusted by the marginal probability that hydrocarbons are present. This is the probability that oil or gas are present in commercial quantities. The marginal probabilities for all planning areas are presented in Table 3. To get the unconditional (i.e. risked) estimate of resources in each basin one simply multiplies the conditional resource estimate by the marginal probability. The unconditional resource estimates are presented in Table 4. These estimates are often referred to as expected resources. Unconditional or expected resources are those resources which are expected to occur on a probabilistic basis. Some basins, for one reason or another, will lack petroleum accumulation, while others will hold commercial resources. Unconditional resources are simply the adjustment of conditional resource estimates by the expectation of petroleum accumulation.

An example which may assist in the understanding of the difference between conditional and unconditional resources is as follows. Suppose there are 5 frontier petroleum basins each of which have a conditional resource estimate of 10 billion BOE and the marginal probability of petroleum accumulation in each is 0.2. The total expected resources is 10 billion BOE. This could occur if only one basin

Table 2. OCS Planning Areas Ranked By
Conditional Resource Estimates

	Total BOE (10^9 BBL)	Oil (10^9 BBL)	Gas (TCF)
1. Central Gulf of Mexico	9.5	3.2	34.9
2. North Atlantic*	7.0	4.0	16.7
3. Western Gulf of Mexico	6.1	1.5	26.3
4. Diapir Field	5.4	2.8	14.8
5. Navarin Basin	2.5	1.1	7.3
6. Southern California	2.3	1.8	3.1
7. South Atlantic	1.9	1.1	4.3
8. Barrow Arch	1.7	0.9	4.2
9. Eastern Gulf of Mexico	1.5	1.2	1.6
10. St. George Basin	1.4	0.7	3.9
11. Kodiak	1.1	0.6	3.2
12. Central and Northern California	1.1	0.9	1.2
13. Gulf of Alaska	1.1	0.5	3.0
14. North Aleutian Basin	0.8	0.5	2.2
15. Norton Basin	0.7	0.3	2.2
16. Shumagin	0.4	0.2	1.4
17. Hope Basin	0.3	0.1	1.2
18. Cook Inlet	0.2	0.1	0.7

*The old North and Mid-Atlantic areas which are combined in the new North Atlantic area, contain the following conditional resources:

(Old North Atlantic	2.3	1.4	5.8)
(Old Mid-Atlantic	4.7	2.69	11.3)

BOE = Barrels of oil equivalent
BBL = Barrel
TCF = Trillion Cubic Feet.

Table 3. OCS Planning Areas Ranked by Probability that Hydrocarbon is Present

		Probability
1.	Central Gulf of Mexico	1.00
2.	Western Gulf of Mexico	1.00
3.	Diapir Field	1.00
4.	Southern California	1.00
5.	Cook Inlet	1.00
6.	North Atlantic*	.9997
7.	Central and North California	.99
8.	Eastern Gulf of Mexico	.87
9.	South Atlantic	.84
10.	Navarin Basin	.76
11.	Barrow Arch	.76
12.	Gulf of Alaska	.66
13.	St. George Basin	.64
14.	Kodiak	.61
15.	Norton Basin	.57
16.	Shumagin	.43
17.	North Aleutian Basin	.42
18.	Hope Basin	.24

*The old North and Mid-Atlantic areas which are combined in the new North Atlantic area, contain the following probabilities of hydrocarbon accumulation:

(Old North Atlantic	.93)
(Old Mid-Atlantic	.996)

Table 4. OCS Planning Areas Ranked by Expected Resource Estimates

		BOE(10^9)
1.	Central Gulf of Mexico	9.5
2.	North Atlantic*	7.0
3.	Western Gulf of Mexico	6.1
4.	Diapir Field	5.4
5.	Southern California	2.3
6.	Navarin Basin	1.9
7.	South Atlantic	1.6
8.	Barrow Arch	1.3
9.	Eastern Gulf of Mexico	1.3
10.	Central and Northern California	1.1
11.	St. George Basin	0.9
12.	Gulf of Alaska	0.7
13.	Kodiak	0.7
14.	Norton Basin	0.4
15.	North Aleutian Basin	0.4
16.	Shumagin	0.2
17.	Cook Inlet	0.2
18.	Hope Basin	0.1

*The comparable figures for the old north and Mid-Atlantic regions are:

(Old North Atlantic 2.3)

(Old Mid-Atlantic 4.7)

is found to be productive. Yet, for management purposes, decisions should be based on knowledge that each has an unconditional resource estimate of 2 billion BOE reflecting the equal chance for each of the basins.

One question which arises in the process of analyzing the benefits and costs of OCS leasing is whether conditional or unconditional resources should be used as the basis of the analysis.

The case for using unconditional resources appears quite strong. In managing the public resources, the government should establish policies and programs that maximize the net present value derived. It is well established that investments in uncertain conditions yield the maximum payoff if they are based on expected values, that is the value of the possible outcomes adjusted by the chance that it will occur. This principle is well known and commonly applied in such diverse activities as investing and gambling.

It should be noted that the supplemental EIS on the 5-Year OCS Program uses the conditional resource estimates. This allows a clearer statement of the environmental effects that can occur in each area if oil and gas is discovered. It also allows the assessment of policies and measures to mitigate damaging effects. The use of different resource estimates for the estimation of economic value and the assessment of environmental effects reflects the different emphasis of the two types of analysis.

Resource Value

Once expected resource estimates have been made for each planning area, the focus of the analysis shifts to the estimation of net economic value per barrel in each planning area. Net economic value per barrel is the expected average difference between the product price and the cost of exploration, development production and transportation to market.

The assumed base price of oil used in the analysis is $35 per barrel. Since additional domestic production will serve to displace imports the appropriate benchmark is the refiner acquisition cost of imported oil. For the first five months of 1981, the refiner acquisition cost was somewhat above this figure, although prices were trending downward. The average refiner acquisition cost for imports in 1980 was under $34 per barrel. In light of the recent volatility of import prices, $35 per barrel appears reasonable. Because the price of imported oil eliminated by production in each area of the OCS is essentially the same, small differences in the choice of the price would not significantly affect the relative results from area to area.

For the calculation of net economic value, the cost of production does not include the value per barrel which would be expected to be paid as a bonus bid, taxes, or royalties. These are not true costs, but merely the forms of transfer payments by which the net value is paid to the government. However, most of the economic models available calculate the after tax, net present value which is the residual left after royalties and taxes have been paid. For purposes of this analysis the net economic value per barrel of resource was calculated by finding this residual value per barrel in each area and extrapolating to the net economic value. The residual value per barrel depends upon the costs expected in each region as well as assumptions about field sizes. For example, the average cost of wells drilled off southern California is likely to be greater than average costs in the Gulf of Mexico because of greater water depths. However, because the fields to be discovered in Southern California waters are expected by the Geological Survey to be larger, yielding greater economies of scale than those discovered in the Gulf, the relevant cost per barrel produced is expected to be lower in Southern California waters.

The estimates of the residual value per barrel are based on two sources. In the first place, the Department has substantial experience in evaluating tracts for OCS lease sales and has compared the actual bids with tract value estimates. Where substantial Departmental experience is available, such as in the Gulf of Mexico and off California, this analysis has used Departmental estimates. Departmental estimates were prepared for other areas as well and were used as part of the basis of the estimates about those areas. In these other areas where Departmental sale experience is less extensive or non-existent, the estimate was considered in light of other information available.

The second source of information about the residual value per barrel in the OCS planning areas is the output from the DOE computer simulation model used in the preparation of the report entitled, Federal Leasing and Outer Continental Shelf Energy Production Goals. This model uses assumptions about the costs and field sizes in each OCS planning area to estimate the value of leasing in each. Using the recent results from this DOE model, rough estimates of the value per barrel in each area were made and compared with the estimates made by the Department. The DOE model was particularly useful in determining the value of resources in frontier OCS planning areas.

In summary, where the Department has already done considerable work in estimating the residual value of resources in frontier OCS basins, these values were used. For other areas where the Department's experience is more limited, both the DOE and Departmental estimates were considered together in establishing an estimate to be used. Both sources yield estimates of residual value that reflect the costs and phasing of exploration, development, and production and transportation in the various OCS areas. The estimates used, though educated guesses, are probably the the best available estimates of the average value of undiscovered resources in each planning area.

The net economic value of resources per barrel was calculated from the residual value using the following equation;

$$\text{Net Economic Value} = \frac{\text{Residual Value}}{.52} + 5.8$$

This equation considers the effects of taxes at a 48% tax rate and royalties at 1/6. Table 5 presents the estimates of net economic value per barrel for each region.

Table 5. OCS Planning Areas Ranked
by Net Economic Value per Barrel
($/bbleq.)

		Net Economic Value	Residual Value
1.	Southern California	15.40	5.00
2.	Central Gulf of Mexico	13.50	4.00
3.	Western Gulf of Mexico	13.50	4.00
4.	Eastern Gulf of Mexico	13.50	4.00
5.	Central and Northern California	13.50	4.00
6.	Cook Inlet	10.60	2.50
7.	Gulf of Alaska	10.60	2.50
8.	Shumagin	10.60	2.50
9.	Kodiak	10.60	2.50
10.	Navarin Basin	9.15	1.75
11.	North Atlantic	9.60	2.00
12.	South Atlantic	9.60	2.00
13.	St. George Basin	9.15	1.75
14.	Diapir Field	8.70	1.50
15.	North Aleutian Basin	8.70	1.50
16.	Barrow Arch	8.20	1.25
17.	Hope Basin	7.25	0.75
18.	Norton Basin	7.25	0.75

Table 6 presents the summary of the estimates. The expected resources in each basin were multiplied by the estimated net economic value per barrel to arrive at the net economic value of resources in each basin.

The net economic value estimates in Table 3 need to be considered in light of the possibility that some or all of the recoverable gas discovered in Alaskan provinces may not be produced because of transportation costs. The estimates shown in Tables 2 and 3 assume for all regions that recoverable resources of gas will be produced and delivered to market. However, decisions on development of oil and gas fields in Alaska are very sensitive to costs, particularly the transportation costs. Transportation of gas from Alaskan basins is generally more costly than an equivalent quantity of oil. Given the high cost of production in these remote Alaskan regions, the difference in transportation costs between oil and gas may well result in a considerable amount of discovered gas going unproduced for a significant period of time.

A 1981 study by the National Petroleum Council (NPC) found that of 68 trillion cubic feet (TCF) of potentially recoverable non-associated gas, only 10 TCF are economical to produce and transport to market assuming industry requires a 10% rate of return (at 15% none would be economical). This estimate is based on the assumed price of $6.50 per thousand cubic feet, which is somewhat higher than the current price of gas would be if it were deregulated. However, an analysis by DOE indicates that a real $6.50 price may be obtained by the late 1980's under deregulation. Without deregulation the gas could be produced today and "rolled in" with lower price gas.

On the other hand, a study by the Energy Productivity Center of the Mellon Institute has forecast that gas prices may be as much as 40% less than oil prices. To the extent that deregulated gas prices lag behind those of oil prices, less gas production can be expected from remote Alaskan OCS planning areas. Thus, under deregulation, the NPC estimate of the extent of Alaskan gas production may be an overstatement. Without deregulation, however, the gas could be produced and transported at higher cost and "rolled in" with lower price gas. This would result in more Alaskan gas being produced.

From another perspective, the NPC's estimates are somewhat conservative since they assume that "grass roots" transportation systems will be required for each basin. They ignore the possibility that some gas from the Diapir Field or the Barrow Arch may be transported through the ANGTS pipeline system. The NPC study found that only gas from the Navarin, St. George, Norton, and North Aleutian basins might be recoverable. The probabilities of finding the minimum economic reserve size for each basin are 18%, 16%, 7%, and 14%, respectively. If the ANGTS pipeline is built, however, it is likely that gas production from the Diapir Field will occur if pipeline capacity is available. This would add 4.1 TCF of non-associated gas production according to the NPC or 14.75 TCF of associated and non-associated gas production according to USGS.

The NPC study is also somewhat conservative in considering only non-associated gas for development. The study assumed that all associated gas would be reinjected to maintain reservoir pressure or burned on-site for fuel.

Table 6. OCS Planning Areas Ranked by Expected
Net Economic Value of Total Production*

		NEV ($\$10^{9}$)
1.	Central Gulf of Mexico	128
2.	Western Gulf of Mexico	82
3.	North Atlantic**	67
4.	Diapir Field	47
5.	Southern California	36
6.	Eastern Gulf of Mexico	18
7.	Navarin Basin	17
8.	South Atlantic	15
9.	Central and Northern California	14
10.	Barrow Arch	11
11.	St. George Basin	8
12.	Gulf of Alaska	7
13.	Kodiak	7
14.	North Aleutian Basin	3
15.	Norton Basin	3
16.	Cook Inlet	2
17.	Shumagin	2
18.	Hope Basin	0.8

* The comparable <u>expected</u> value of St. Matthew-Hall is zero.

** The comparable figures for the Old North and Mid-Atlantic provinces are;

(Old North Atlan'	22)
(Old Mid-Atlar	45)

2861

Table 6a shows the effect of excluding gas from the estimates of net economic value of development of the expected resources in all Alaskan basins except in the Diapir Field.

The estimates of net economic value did not include any estimate of the benefits from reduced requirements for the Strategic Petroleum Reserve due to higher production levels. The net economic benefits are thus understated by 5% to 10%. In addition, the estimates of net economic value did not include any allowance for "premium" value of domestic oil production above the value set by the world price. Such a premium may result from decreased vulnerability to import disruption. Such estimates range from a few dollars to nearly $100 per barrel, but there is substantial uncertainty as to their validity. By neglecting these benefits of decreased economic disruption that accrue from import disruptions when domestic production is higher, the net economic value estimates again understate the potential national benefits of OCS oil and gas production.

The estimates of the net economic value of total production in each area reflect the phasing of exploration, development and production that would result if all of the estimated resources of the area were leased at once in the first year of the program. The resulting estimates are thus independent of the rate of leasing and the timing and location of lease sales. This approach was necessary to permit comparisons of the potential contribution that each area can make to meeting national economic and energy needs. The estimates on Tables 5 and 6 should not be regarded as forecasts of the production and economic benefits that will result in OCS areas under any leasing program under consideration. Such sale specific estimates are discussed in the next section.

(Table 6a OCS Planning Areas Ranked by Expected Net Economic Value of Total Production Excluding Gas Production on the Alaskan OCS).

		NEV ($\$10^9$)
1.	Central Gulf of Mexico	128
2.	Western Gulf of Mexico	82
3.	North Atlantic	67
4.	Diapir Field*	47
5.	Southern California	36
6.	Eastern Gulf of Mexico	16
7.	South Atlantic	15
8.	Central and Northern California	14
9.	Navarin Basin	9
10.	Barrow Arch	6
11.	St. George Basin	5
12.	Gulf of Alaska	4
13.	Kodiak	4
14.	North Aleutian Basin	2
15.	Norton Basin	2
16.	Cook Inlet	1
17.	Shumagin	1
18.	Hope Basin	.02

* Since it is assumed that the Alaskan Natural Gas Transportation System will be built, gas from the Diapir Field is assumed to be produced.

Estimating the Value of Alternative OCS Lease Sale Schedules

The net present economic value of any lease sale is determined by the amount of resources expected to be leased and discovered, prices and costs obtaining at the time of exploration and production, and the year in which the lease sale occurs. The estimates of net present value for each sale were derived by taking a percentage of the total net economic value of the area that reflects the amount of resource expected to be leased, and adjusting that value for expected price increases and discounting to present value. Determining the net economic value of alternative lease sale schedules is simply a matter of aggregating the present value of all sales in the schedule. Sales excluded from one sale schedule but included in another cannot properly be evaluated in the former since there is no policy commitment to holding the sales at a later date, and the only question before the Secretary is which of the alternative five year schedules to select.

Resources to be Leased and Developed

Perhaps the most difficult aspect of evaluating the economic value of a lease sale is the assumption about the quantity of resources which will be leased and developed. This analysis has used U.S.G.S. estimates for the proportion of the total undiscovered resources in an area that will be found as a result of each lease sale. (See Attachment 1). Consideration was given to historical patterns of leasing and exploration, the effects of existing infrastructure for offshore operations, likely field sizes and available analogues in well explored areas. These estimates are the result of the Geological Survey's extensive experience in resource evaluation and in the sale and administration of OCS leases over the past 25 years. Nevertheless, there is substantial uncertainty about the way in which industry will respond to increased lease offerings over the next 5 years.

One factor making this task difficult is the fact that exploration is a sequential process in which information gained from one tract can be applied to the evaluation of other tracts in the area. It is difficult to anticipate the results of early exploration in an area on the extent of leasing in later sales. The actual pattern of leasing will be less intensive in aras with negative results from exploration in initial years and more intensive in areas with significant discoveries.

Expected Price Increases

As explained above, the assumed price in the analysis for each barrel of oil is $35 per barrel. However, petroleum is one of the few products for which real price increases can be expected. The level of real price increase used in the analysis is 1%. This is consistent with the assumptions the Department has made in most lease sale designs in the past year. This assumption is also in line with a study prepared for the Department by Resource Consulting Group. Incorporating Petroleum Price Changes in Pre-Sale Evaluation of OCS Tracts. This study, completed in October, 1980, compared seventeen major studies* of petroleum price forecasts. The 1% figure used in this analysis was within the low range estimated by the study. The most likely rate of price growth was estimated as 2.5-3.5 percent per year, with 5.5-6.5 percent being the range under the high growth rate scenario. Since the study's completion, world price trends have moderated somewhat, indicating a somewhat lower long run trend. It is important to recognize that the resources leased by a 5-Year OCS Leasing Program will be developed and produced over a 20 to 30 year period. Recent trends in oil prices, whether sharply upward as they were during the 1970's, or downward as they have been in recent months, are not necessarily indicative of long run trends. It is essentially impossible to forecast the ups and downs of prices over a 20 to 30 year period. On the other hand, the comparison of alternative leasing programs needs to reflect long run trends. It is much more likely that the long run price trend will be increases of 1% to 3% per year than 5% to 10%. The lower rate of price increase is consistent with economic theories of the development of exhaustible resources. In addition, the recent softness in world oil prices demonstrates that the effect of continued high rates of oil price growth is to spur investment in substitute energy sources and, more importantly, in equipments in both the producing and consuming sectors that are more efficient in using energy. The effect of this medium run response to rapid increases in oil prices is to significantly reduce world demand for oil and undercut the ability of oil exporters to continue the high rate of price increases.

It should also be remembered that inflation, caused in part at least by oil price rises, has the effect of partially undoing the increases in oil prices. Because of inflation, the real rate of price increase in the 1970's has been substantially less than the nominal rate.

Long run increases in the 5% to 10% range would significantly reduce the costs of delaying oil and gas development and would make it beneficial to delay development of a greater number of reservoirs. However, such increases appear so unlikely for the long run that they do not form a reasonable basis for the analysis of leasing programs.

Long run increases in the 1% to 3% range, on the other hand, are an appropriate assumption on which to base this analysis. As shown above, the optimal times for development of most of the currently economical resources of the OCS do not vary significantly over this range. The cost of delay analysis discussed below will show the effect of price increases over this range on the net economic value of resources leased in later years.

---

* These studies generally tried to predict future activity in the world petroleum market, particularly the behavior of the OPEC cartel, in making projections.

Cost of Delay

Holding a lease sale at a later date is likely to cause the net present value of the sale to decline.** We may characterize the effect of delaying a sale to a later year than the present as the "cost of delay." This cost can be calculated as follows;

$$L = \left[1 - \left(\frac{1 + r}{1 + i}\right)^N \right] P - \left[1 - \left(\frac{1 + s}{1 + i}\right)^N \right] C$$

where L = per barrel loss in present value as a result of delay

i = interest rate (discount rate)

r = expected rate of real price increase (assumed at 1%)

s = expected rate of real cost increase (assumed to be zero)

P = Price per barrel of oil (assumed at $35)

C = Cost per barrel (varies by sale area)

N = Years of delay between the current year and the year of sale

In calculating the cost of delay for a future OCS lease sale, the estimate must reflect the present value loss between the current year and the year in which it is actually held. The net economic value of each sale is then simply the product of the expected amount of resources to be found for each lease sale and the expected net economic value per barrel in each OCS Planning Area adjusted for the appropriate number of years until the sale.

The approximate cost of delaying lease sales in each of the OCS areas is presented in Table 7 along with the expected net economic value in each. By and large, the cost of delay is relatively constant for a given interval of delay. Thus, it matters little, in terms of cost of delay, whether the sale was originally scheduled for 1982 or 1984, for example. To test the sensitivity of the average costs of a one year delay under greater rates of price increase, calculations were made at 2% and 3%. At 2% annual price increase, the cost of delaying production worth $15.40 per barrel in the Southern California area is $0.25 per barrel. At 3% this cost is $0.17 per barrel. At 2%, the costs of delaying production worth $7.25 per barrel is zero while at 3% price increase, a gain of $0.32 per barrel

---

** Note that in certain circumstances the expected net present value will increase as the result of delay. Such circumstances include an expectation of high real price increases and a low net economic value per barrel. We have not found any OCS basin to which this condition applies on average at 1% annual price increase.

Table 7. The Cost of Delay by OCS Planning Areas

		Net Economic Value ($ per barrel)	Cost of Delay Per Year ($ per barrel)
1.	Southern California	$15.40	$0.82
2.	Central Gulf of Mexico	$13.50	$0.68
3.	Western Gulf of Mexico	$13.50	$0.68
4.	Eastern Gulf of Mexico	$13.50	$0.68
5.	Central and Northern California	$13.50	$0.68
6.	Cook Inlet	$10.60	$0.46
7.	Gulf of Alaska	$10.60	$0.46
8.	Shumagin	$10.60	$0.46
9.	Kodiak	$10.60	$0.46
10.	North Atlantic*	$ 9.60	$0.37
11.	South Atlantic	$ 9.60	$0.37
12.	St. George Basin	$ 9.15	$0.35
13.	Navarin Basin	$ 9.15	$0.35
14.	Diapir Field	$ 8.70	$0.32
15.	North Aleutian Basin	$ 8.70	$0.32
16.	Barrow Arch	$ 8.20	$0.28
17.	Norton Basin	$ 7.25	$0.21
18.	Hope Basin	$ 7.25	$0.21

---

* Note the cost of delay per barrel for the Old North and Mid-Atlantic regions is $0.37.

results from a year's delay. Thus, long run increases of 2% would not yield gains from delay of production having average value in any area. On the other hand, long run increases of 3% could yield gains from delay in production of average value resources in some of the more costly areas. Even so, it should be noted that each area contains reservoirs that are above the average in value. These reservoirs are larger and more likely to be discovered. Thus, even if there might be gains from delaying production of the average value reservoirs in an area, there would be losses if the above average reservoirs likely to be discovered in the first leases issued were to be withheld.

Year of the Lease Sale

The year of the lease sale is the last factor needed to estimate the net economic value of alternative lease sale schedules. As noted elsewhere in this analysis, society generally prefers to consume resources earlier than later. Therefore the value of resources to be consumed in the future is discounted to the present at 8% to reflect society's other investment opportunities.

Schedule by Schedule Comparisons

Tables 8-13 provide estimates of the net present economic value of the six alternative schedules. Table 14 provides a summary comparison of the sale schedules as well as comparing each sale schedule on a yearly basis.

In comparing the sale schedules, one should keep in mind that they are based on different assumptions about the amount of acreage made available. For example under Alternatives III-1 and III-2 the assumption is made that the traditional sales are held, but that the acreage made available for leasing is somewhat greater under Alternative III-2. This should be compared to Alternatives I and II in which areawide sales are held. Obviously considerably more acreage is available under these two alternatives.

Reoffering Sales

Reoffering sales were included in the June 1980 Leasing Program to provide an opportunity for firms to acquire tracts that were offered but went unleased in previous sales. Tracts may go unleased because either bids on them are rejected as too low or they received no bids. Notice that under the Alternative I, no reoffering sales are scheduled after June, 1982. Reoffering sales are unnecessary under the area-wide concept, since, in essence, each sale in a planning area reoffers the entire area to prospective bidders. Reoffering sales under Alternatives III are not assumed to provide any increased leasing totals. Rather, they represent a means to assure that industry has an additional opportunity to acquire the resources that are expected to be leased.

Table 8. Present Net Economic Value of Sales Proposed to Occur under Alternative OCS Leasing Schedules Including the Cost of Delay

Alternative I

Sale	Present Net Economic Value ($ billions)	
1982, 67 & 69 Gulf of Mexico	11.1	
68 S. California	5.4	
52 N. Atlantic	4.4	
71 Diapir Field	14.1	
57 Norton Basin	1.5	
Total Value 1982		36.5
1983, 73 C. & N. California	4.2	
70 St. George Basin	2.0	
76 Mid-Atlantic	13.0	
75 N. Aleutian Basin	1.3	
72 C. Gulf of Mexico	3.7	
78 S. Atlantic	3.6	
74 W. Gulf of Mexico	1.6	
79 E. Gulf of Mexico	1.7	
Total Value 1983		31.1
1984, 80 S. California	6.4	
82 N. Atlantic	12.4	
83 Navarin Basin	4.0	
81 C. Gulf of Mexico	2.3	
87 Diapir Field	8.7	
84 W. Gulf of Mexico	1.5	
88 Norton Basin	0.4	
94 E. Gulf of Mexico	0.8	
89 St. George Basin	1.5	
Total Value 1984		38.0
1985, 90 Atlantic	2.5	
85 Barrow Arch	2.4	
91 C. & N. Calif.	3.2	
92 N. Aleutian Basin	0.6	
98 C. Gulf of Mexico	2.2	
86 Hope Basin	0.4	
102 W. Gulf of Mexico	1.4	
100 S. Alaska	2.5	
103 E. Gulf of Mexico	0.7	
Total Value 1985		15.9

Alternative I (cont.)

Sale	Present Net Economic Value ($ billions)	
1986, 95 S. California	4.2	
96 Atlantic	11.4	
107 Navarin Basin	3.7	
104 C. Gulf of Mexico	2.0	
97 Diapir Field	4.0	
105 W. Gulf of Mexico	1.3	
99 Norton Basin	0.3	
106 E. Gulf of Mexico	0.7	
101 St. George Basin	0.7	
Total Value 1986		28.3
Total for Alternative I		149.8

Table 9. Alternative II

Sale	Net Present Economic Value ($ billions)	
1982, 67 & 69 Gulf of Mexico	11.1	
68 S. California	5.4	
57 Norton Basin	1.5	
52 North Atlantic	4.4	
71 Diapir Field	14.1	
70 St. George Basin	2.1	
Total Value 1982		38.6
1983, 73 California	4.2	
76 Mid-Atlantic	13.0	
75 N. Aleutian Basin	1.3	
72 & 74 Gulf of Mexico	6.9	
78 S. Atlantic	3.6	
83 Navarin Basin	4.2	
Total Value 1983		33.2
1984, 80 California	6.4	
82 N. Atlantic	12.4	
87 Diapir Field	8.7	
79 & 81 Gulf of Mexico	4.6	
88 Norton Basin	0.4	
89 St. George Basin	1.5	
Total Value 1984		34.0
1985, 85 Barrow Arch	2.4	
90 Atlantic	2.5	
91 California	3.2	
84 & 94 Gulf of Mexico	4.3	
92 N. Aleutian Basin	0.6	
86 Hope Basin	0.4	
93 St. Matthew-Hall	0	
Total Value 1985		13.4
1986, 95 California	4.2	
96 Atlantic	11.4	
97 Diapir Field	4.0	
98 & 102 Gulf of Mexico	4.1	
99 Norton Basin	0.3	
100 S. Alaska Basin	2.3	
101 St. George Basin	0.7	
Total Value 1986		27.0
Total for Alternative II		146.2

Table 10. Alternative III-1

Sale	Net Present Economic Value ($ billions)	
1982, 67 & 69 Gulf of Mexico	10.6	
68 S. California	5.4	
57 Norton Basin	1.5	
52 N. Atlantic	4.4	
70 St. George Basin	2.1	
Total Value 1982		24.0
1983, 71 Diapir Field	13.7	
72 & 74 Gulf of Mexico	5.0	
61 Kodiak	0.8	
73 California	3.2	
75 N. Aleutian Basin	1.3	
76 Mid Atlantic	9.8	
Total Value 1983		33.8
1984, 78 S. Atlantic	2.1	
79 & 81 Gulf of Mexico	3.3	
80 California	4.8	
82 N. Atlantic	4.1	
83 Navarin Basin	3.2	
Total Value 1984		17.5
1985, 84 Gulf of Mexico	2.6	
85 Barrow Arch	1.9	
86 Hope Basin	0.4	
Total Value 1984		4.9
Total Alternative III-1		80.2

Table 11. Alternative III-2

Sale	Net Present Economic Value ($ billions)	
1982, 67 & 69 Gulf of Mexico	10.6	
68 S. California	5.4	
57 Norton Basin	1.5	
52 N. Atlantic	4.4	
70 St. George Basin	2.1	
Total Value 1982		24.0
1983, 71 Diapir Field	13.7	
72 & 74 Gulf of Mexico	6.6	
61 Kodiak	1.0	
73 California	4.2	
75 N. Aleutian Basin	1.3	
76 Mid-Atlantic	13.0	
Total Value 1983		39.8
1984, 78 S. Atlantic	2.7	
79 & 81 Gulf of Mexico	4.4	
80 California	6.4	
82 N. Atlantic	4.1	
83 Navarin Basin	4.0	
Total Value 1984		21.6
1985, 84 Gulf of Mexico	3.5	
85 Barrow Arch	2.4	
86 Hope Basin	0.4	
Total Value 1985		6.3
Total for Alternative III-2		91.7

Table 12. Alternatives IV-1 and IV-2

Sale	Net Present Economic Value ($ billions)	
1982, 67 & 69 Gulf of Mexico	11.1	
68 S. California	5.4	
52 N. Atlantic	4.4	
71 Diapir Field	14.1	
57 Norton Basin	1.5	
Total Value 1982		36.5
1983, 73 C. & N. California	4.2	
76 Mid-Atlantic	13.0	
72 C. Gulf of Mexico	3.7	
78 S. Atlantic	3.6	
74 W. Gulf of Mexico	1.6	
79 E. Gulf of Mexico	1.7	
Total Value 1983		14.8
1984, 80 S. California	6.4	
82 N. Atlantic	12.4	
81 C. Gulf of Mexico	2.3	
87 Diapir Field	8.7	
84 W. Gulf of Mexico	1.5	
100 S. Alaska	2.6	
94 E. Gulf of Mexico	0.8	
Total Value 1984		34.7
1985, 90 Atlantic	2.5	
91 N. California	3.2	
98 C. Gulf of Mexico	2.2	
83 Navarin Basin	4.0	
102 W. Gulf of Mexico	1.4	
97 Diapir Field	4.4	
103 E. Gulf of Mexico	0.7	
Total Value 1985		18.4
1986, 95 S. California	4.2	
96 Atlantic	11.4	
70 St. George Basin	1.7	
104 C. Gulf of Mexico	2.0	
99 Norton Basin	0.4	
105 W. Gulf of Mexico	1.3	
85/86 Barrow Arch/Hope Basin	2.9	
106 E. Gulf of Mexico	0.7	
Total Value 1986		24.6
Total for Alternatives IV-1 and IV-2		129.0

Table 13. Alternatives V-1 and V-2

Sale	Net Present Economic Value ($ billions)		
1982, 67 & 69 Gulf of Mexico	11.1		
68 S. California	5.4		
52 N. Atlantic	4.4		
57 Norton Basin	1.5		
Total Value 1982		22.4	
1983, 73 C. & N. California	4.2		
70 St. George Basin	2.0		
76 Mid-Atlantic	13.0		
75 N. Aleutian Basin	1.3		
72 C. Gulf of Mexico	3.7		
78 S. Atlantic	3.6		
74 W. Gulf of Mexico	1.6		
79 E. Gulf of Mexico	1.7		
Total Value 1983		31.1	
1984, 80 S. California	6.4		
82 N. Atlantic	12.4		
83 Navarin Basin	4.0		
81 C. Gulf of Mexico	2.3		
84 W. Gulf of Mexico	1.5		
88 Norton Basin	0.4		
94 E. Gulf of Mexico	0.8		
89 St. George Basin	1.5		
Total Value 1984		29.3	
1985, 90 Atlantic	2.5		
91 N. California	3.2		
98 C. Gulf of Mexico	2.2		
92 N. Aleutian Basin	0.6		
102 W. Gulf of Mexico	1.4		
100 S. Alaska	2.5		
103 E. Gulf of Mexico	0.7		
Total Value 1985		13.1	
1986, 95 S. California	4.2		
96 Atlantic	11.4		
107 Navarin Basin	3.7		
104 C. Gulf of Mexico	2.0		
105 W. Gulf of Mexico	1.3		
99 Norton Basin	0.3		
106 E. Gulf of Mexico	0.7		
101 St. George Basin	0.7		
Total Value 1986		24.3	
Total for Alternatives V-1 and V-2			120.2

Table 14

Summary of Net Present Economic Values of Alternative OCS Lease Schedules ($ Billions)

	Net Present Economic Value	Cumulative Net Present Economic Value
1982		
ALT. I	36.5	36.5
ALT. II	38.6	38.6
ALT. III-1	24.0	24.0
ALT. III-2	24.0	24.0
ALT. IV-1 & IV-2	36.5	36.5
ALT. V-1 & V-2	22.4	22.4
1983		
ALT. I	31.1	67.6
ALT. II	33.2	71.8
ALT. III-1	33.8	57.8
ALT. III-2	39.8	63.8
ALT. IV-1 & IV-2	14.8	51.3
ALT. V-1 & V-2	31.1	53.5
1984		
ALT. I	38.0	105.6
ALT. II	34.0	105.8
ALT. III-1	17.5	75.3
ALT. III-2	21.6	85.4
ALT. IV-1 & IV-2	34.7	86.0
ALT. V-1 & V-2	29.3	82.8
1985		
ALT. I	19.9	121.5
ALT. II	13.4	119.2
ALT. III-1	4.9	80.2
ALT. III-2	6.3	91.7
ALT. IV-1 & IV-2	18.4	104.4
ALT. V-1 & V-2	13.1	95.9
1986		
ALT. I	28.3	149.8
ALT. II	27.0	146.2
ALT. III-1	0	80.2
ALT. III-2	0	91.7
ALT. IV-1 & IV-2	24.6	129.0
ALT. V-1 & V-2	24.3	120.2

Estimates of Conditional Resources and Percent Resources Leased
Alternatives I, IV-1, IV-2

Planning Area	Conditional Mean Resources Oil (BBO)	Conditional Mean Resources Gas (TCFG)	MP_{HC}	Sale	Percent Resources Leased & Developed
W. GOM	1.47	26.26	1.00	67	1.5
				69	1.5
				74	2
				84	2
				102	2
				105	2
C. GOM	3.24	34.92	1.00	67	2
				69	2
				72	3
				81	2
				93	2
				104	2
E. GOM	1.23	1.57	.87	67	10
				69	10
				79	10
				94	5
				103	5
				106	5

Alternative I*

Planning Area	Conditional Mean Resources Oil (BBO)	Gas (TCFG)	MP HC	Sale	Percent Resources Leased & Developed
Diapir Field	2.77	14.75	1.00	71	30
				87	20
				97	10
Barrow Arch	.935	4.20	.76	85	25
Hope Basin	.074	4.20	.24	86	67
Norton Basin	.274	2.17	.57	57	50
				88	15
				99	10
Navarin Basin	1.14	7.34	.76	83	25
				107	25
North Aleutian	.45	2.16	.42	75	40
				92	20
St.George Basin	.71	3.94	.64	70	25
				89	20
				101	10
South Alaska	.85	4.99	1.00	100	15
C.N. California	.86	1.20	.99	73	30
				91	25
S.California	1.79	3.07	1.00	68	15
				80	20
				95	15
S. Atlantic	1.14	4.30	.84	78	20
				90	15
N. Atlantic	4.00	16.73	.9997	82	20
				96	20
Mid-Atlantic (Old)	2.69	11.27	.966	76	30
N. Atlantic (Old)	1.42	5.84	.93	52	20

*Also for sales included in Alternatives IV-1 and IV-2 except for sale 99 which is estimated to lease and develop 15% of the resources.

Alternative II

Planning Area	Conditional Mean Resources Oil (BBO)	Gas (TCFG)	MP HC	Sale	Percent Resources Leased & Developed
Diapir Field	2.77	14.75	1.00	71	30
				87	20
				97	10
Barrow Arch	.94	4.20	.76	85	25
Hope Basin	.07	1.24	.24	86	25
Norton Basin	.27	1.24	.57	57	50
				88	15
				99	10
Navarin Basin	1.14	7.34	.76	83	25
North Aleutian	.45	2.16	.42	75	40
				92	20
St.George Basin	.71	3.94	.64	70	25
				89	20
				101	10
S. Alaska	.85	4.99	1.00	100	15
St.Matthew-Hall	0	0	0	93	0
C.N. California	.86	1.20	.99	73	30
				91	25
S. California	1.79	3.07	1.00	68	15
				80	20
				95	15
S. Atlantic	1.14	4.30	.84	78	20
				90	15
N. Atlanitc	4.00	16.73	.9997	82	20
				96	20
Mid-Atlantic (Old)	2.69	11.27	.996	76	30
N. Atlantic (Old)	1.42	5.84	.93	52	20

Alternative II

Planning Area	Conditional Mean Resources Oil (BBO)	Gas (TCFG)	MP HC	Sale	Percent Resources Leased & Developed
W. GOM	1.43	25.42	1.00	67	1.5
				69	1.5
				72	2
				79	2
				84	2
				96	2
C. GOM	3.13	33.73	1.00	67	2
				69	2
				72	3
				79	2
				84	2
				96	2
E. GOM	1.16	1.28	.87	67	10
				69	10
				74	10
				81	5
				94	5
				102	5

Alternative III

Planning Area	Conditional Mean Resources Oil (BBO)	Gas (TCFG)	MP_{HC}	Sale	Percent Resources Leased & Developed Current Sale Size	Larger Sale Size
C & W GOM	4.51	60.11	1.00	67	1.8	1.8
				69	1.8	1.8
				72	1.7	2.3
				79	1.4	1.8
				84	1.4	1.8
E. GOM	1.45	2.69	.87	67	7	7
				69	7	7
				74	7.5	10
				81	3.8	5
SBC	.99	1.91	1.00	68	15	15
				80	15	20
S. Calif.	1.78	1.17	1.00	68	15	15
				80	15	20

Alternative III

Planning Area	Conditional Mean Resources Oil (BBO)	Gas (TCFG)	MP HC	Sale	Percent Resources Leased & Developed III-1	III-2
Beaufort Sea	2.77	14.75	1.00	71	30	30
Chukchi Sea	.935	4.20	.76	85	20	25
Hope Basin	.07	1.24	.24	86	67	67
Norton Basin	.27	2.17	.57	57	50	50
North Aleutian	.45	2.16	.42	75	40	40
St.George Basin	.71	3.94	.64	70	25	25
C.N. California	.86	1.20	.99	73	22.5	30
S. California	.79	1.09	1.00	68	10	10
				80	15	20
Santa Barbara	1.27	1.91	1.00	68	15	15
					10	15

APPENDIX 3

Appendix 3

Fair Market Value

Table of Contents

Appendix 3

Fair Market Value

Introduction

This paper discusses the fair market value requirement of Sec. 18(a)(4) of the OCS Lands Act and its relationship to the rate at which leases are offered for sale and the tract evaluation procedures used in determining whether or not to accept bids. It examines the basic concepts of fair market value and concludes that this standard sets a minimum on what the government is to be paid for OCS oil and gas leases. This minimum is the price in a market with characteristics that are, by and large, typical of the OCS lease market.

The paper then analyzes the relationship between such market prices and the rate of leasing. The conclusion is drawn that slow leasing rates would assure receipt of fair market value by exercising the government's monopoly power to sustain high lease prices. However, this approach would be quite costly to the achievement of the basic objectives of the leasing program. Since the lease market operates through a competitive process that satisfies most of the requirements for fair market value even at higher leasing rates, other procedures and policies can be examined as supplements to the lease market. Most important in this category is the Department's tract evaluation procedures.

Basic Concepts of Fair Market Value

Sec. 18(a)(4) of the OCS Lands Act as amended states

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

The Act, however, offers no definition of the term as it applies to leases and mineral rights. However, the term fair market value has been defined by case law and practice in determining the compensation for a taking. Appraisal policy based on this case law clearly shows that the market price is the legally preferred measure of fair market value.

> "Fair market value" is defined as the amount in cash, or on 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. . . .This market value which is sought is not merely theoretical or hypothetical but it represents, insofar as it is possible to estimate it, the actual selling price.
>
> As has been judicially declared: "It is well recognized that where private property is taken for public use, and there is a market price prevailing at the time and place of taking, that price is just compensation.". . . But the measure of compensation is not changed by the lack of active trading. The objective to be reached remains the same, i.e., the price for which the tract in question would sell.'"1/

---

1. Fair Market Value Task Force Report (Bieniewicz pp. V13-V15), and Uniform Appraisal Standards, pp. 3-5.

A knowledgeable seller would clearly not accept less from one buyer than he could get from another buyer. Nor would he knowingly participate in a transaction in which he was being tricked or cheated by collusion among buyers. Prices in such transactions would clearly not be "fair."

The "market value" of a good or property depends on many factors. Some factors influencing market value are characteristics of the property itself. Some are characteristics of the supply of similar properties and substitutes. And some are characteristics of the buyers. In the OCS program, the market value of "the lands leased and the rights conveyed" clearly depends on the oil and gas prospects of the tracts, the expected prices of oil and gas, the costs of OCS operations, the supply of leases and substitutes, and the financial, market, and technological characteristics of potential bidders. The market value of leases is not the market value of the oil and gas eventually discovered or produced, but the value of the right to explore, and, if there is a discovery, develop and produce, subject to a wide array of constraints. The market value of a lease is its value at the time it is offered, given conditions at that time. It is not necessarily the same as the value of the lease at a later time.

The fair market value of an item is not the highest price any buyer would be willing to pay, but the price in a competitive market. In most markets, prices are established at levels below the maximum that many buyers would pay. This is one of the primary advantages of competitive markets. In oral auctions, for example, the high bidder pays only slightly more than the second highest bid. In most consumer and commodity markets, the competitive market price is the price at which all the supply offered can be sold, which is substantially lower than the price the highest bidder would pay.

In summary, to assure receipt of fair market value for the rights conveyed by OCS leases, the Secretary must assure that the payment received for the leases is the price for such leases at the time of their sale that is, or would be, set by a market which is sufficiently competitive to yield fair transactions between buyers and sellers.

Legal Constraints

The Solicitor's office has prepared two memoranda dated March 20 and May 11, 1981 (see attached) discussing the legal aspects of the OCS fair market value requirement and the proposals being considered for tract evaluation. In summary, the conclusions most relevant to consideration of these options are:

1. Fair market value is the amount at which property would change hands between a willing buyer and a willing seller, neither being under any compulsion to buy or sell and both having reasonable knowledge of the relevant facts.

2. In deciding how to assure receipt of fair market value, the Secretary may consider and weigh a variety of objectives and factors enumerated in the OCS Lands Act as amended, including costs, administrative burdens, and delays in development;

3. The decision to reject a bid must be based on an estimate of the tract's value to be defensible as not arbitrary and capricious;

4. Tract evaluations may be done either before or after a sale;

5. Competition in the lease market can be used as a basis for accepting bids as fair market value though full reliance on adequate competition would probably subject entire sales to litigation;

6. Random selection of tracts for evaluation may be used in establishing a deterrent against underbidding and collusion.

Fair Market Value and the OCS Lease Market

The OCS lease market, as currently configured, meets the requirements that a market must satisfy in order for the prices established in that market to be regarded as the fair market value for the items exchanged. This conclusion is supported by an analysis of the requirements that stem from the "knowledgeable seller willing but not obligated to sell. . ." concept of a fair market and by evidence that the OCS market meets such requirements.

The most important feature of prices in a fair market is that they are satisfactory to both parties to the transaction, given their knowledge and voluntary participation. The seller in such a transaction accepts the payment offered in confidence that he could not receive more from another buyer. For such confidence to be placed in a market, it must

- operate through a competitive process;

- provide sufficient opportunity for those who most highly value the item being sold to participate;

- be free of non-market restrictions on, or advantages to, any party competing to purchase the item;

- be free of collusion.

The OCS lease market meets these requirements. As required by statute, it operates only through a competitive sealed bidding process. Ample opportunity is provided for firms valuing a lease most highly to submit bids. The 5 Year OCS Leasing Program provides public notice of the timing and location of lease sales well in advance. In addition, specific details on the leases to be offered are included in proposed and final sale notices published at least 90 and 30 days, respectively, prior to a sale.

The award of an OCS lease to a specific bidder is based only upon the amount of the bid and no other consideration save that the bidder be qualified to conduct operations on the lease. The lease is awarded to the high bidder or not at all. While some firms may have advantages over others in bidding because of their assets and efficiencies in management, technology or information, these are the type of economic advantages which are common features in, indeed are a desired result of, market economies. A primary social value of the market mechanism is its ability to allocate resources to those who can realize the most value from them.

Finally, by law, leases are reviewed to assure that the OCS market is free from collusion. The Antitrust Division of the Justice Department reviews pending lease awards for effects on competition and the Attorney General is authorized to make recommendations to the Secretary of the Interior to prevent any situation inconsistent with the antitrust laws. These reviews have never identified collusive behavior among bidders for OCS leases.

Given the fact that the OCS lease market meets the requirements of a fair market, the Department should have confidence that the high bids it receives more than satisfy the requirement of being fair market value. After all, in a traditional oral auction, the purchaser would pay only slightly more than the second highest bid. In most consumer and commodity markets, all buyers pay the competitively set price rather than the highest amount they would be willing to pay. If such prices are considered to be fair market value, then the high bid for an OCS lease in a competitive lease market can certainly be regarded as such.

However, there are some features in the patterns of past bidding which have made reliance on the lease market as the sole means for assuring receipt of fair market value controversial. Many claims have been made, for example, that because the average number of bids per tract has often fallen between 2 and 3 in a given sale, that competition, at least for many tracts, is not sufficiently intense. In fact, this average obscures a very uneven distribution in the competition for OCS tracts, a distribution which reflects the highly uneven distribution of oil and gas resources and economic value. Most tracts contain no oil or gas and are worthless. Some tracts contain relatively small amounts of resource and have modest value. A very few tracts contain relatively large amounts and are very valuable. Reflecting this distribution, 50% of the tracts offered have drawn no bids, and of those receiving bids, 40% have drawn only 1 bid, while 20% received 2 bids and 10% received 3 bids. Only 30% of the tracts receiving bids, that is, only 15% of the tracts offered, received 4 or more bids. Because bidding is focused on the better prospects, the competition for the resources is intense despite the low number of bids on many tracts.

The fact that so many tracts receive only 1 or 2 bids has caused concern that the bids on such tracts may often be below fair market value. While a seller would not have great confidence in a single bid if only one item was offered, there are several arguments and facts that support the conclusion that, through simultaneous bidding on many tracts, the OCS lease market yields fair market value even for tracts drawing few bids. First, given the cost of preparing and entering bids and the fact that each potential bidder will estimate a different value for a tract because of the uncertainty about its resources, it is reasonable to expect most bidders to decide that many tracts are not sufficiently valuable to warrant a bid. If the firms valuing each tract most highly have ample opportunity to bid and only one thinks the lease worth bidding on, then, one could argue, the fair market value is essentially zero and the one positive bid is more than enough. After all, the government received no better offer and has no reason to think that it would receive more from another bidder.

The second argument is based on the competitive equilibrium which a lease market would tend to achieve. The uneven distribution of bids with so many 1 and 2 bid tracts represents the collective effect of the individual bidders' decisions, each allocating his bidding resources in the manner that he thinks is best from the viewpoint of his own economic situation. In this equilibrium, no bidder would expect to achieve a significant gain by shifting bids from the better prospects to the poorer 1 or 2 bid tracts. This situation is not consistent with the proposition that the bids submitted on low bid tracts are so low as to yield surplus profits to their winners. Any significant surplus profits would represent a potential gain that would be expected to lure at least some bidders into shifting their bidding resources to prospects expected to draw fewer bids. Under stable conditions, bidders will have made any profitable shifts, leaving no anticipated gain from 1 or 2 bid tracts.

There is also evidence that the 1 and 2 bid leases have not, in fact, yielded surplus profits to their owners that would indicate payment of less than fair market value. A study performed by Walter Mead and Philip Sorenson under U.S.G.S. sponsorship estimated the rates of return on OCS leases issued from 1954 through 1969. Using early results from this study, John Lohrenz of the U.S.G.S. showed that the rates of return on 1 and 2 bid tracts have been only slightly higher than rates of return on 3 and 4 bid tracts, and somewhat higher than those on tracts drawing 5 or more bids. The slightly higher rates of return for the lower bid tracts may be explained by the higher risk associated with such tracts. Moreover the rates of return on 1 and 2 bid tracts, as well as rates of return on the aggregate of OCS leases issued during that period, were below those achieved in the manufacturing sector during the same period. This indicates that OCS lessees did not earn surplus profits, providing further strong evidence that the OCS lease market has yielded fair market value to the government.

In addition, the DOE sponsored an elaborate study of OCS competition by the Cabot Consulting Group which was completed in July, 1980. This study concluded that there is no evidence of strategic underbidding for OCS leases and that all of the studies of the profitability of OCS leases indicate that the government has received fair market value.

Although the conceptual arguments in favor of the lease market may hold true even at greatly increased leasing rates, the results of empirical studies of past leasing might not be applicable. It is possible, for example, that competition and bid levels could decline during such a period. This possibility warrants further consideration.

It is likely that substantially expanded leasing will result in lower bids on average and perhaps lower bids for some tracts than they would bring under a more restrictive leasing program. Under the tract selection system, most of the tracts offered for bid are the ones for which there is an industry consensus on their promise. Under area-wide leasing, additional tracts will be available, many of which will be viewed as less promising. These latter tracts are likely to receive lower bids than the more promising tracts, which will have the effect of lowering the average bid.

Because lower value tracts draw fewer bids, the proportion of 1 and 2 bid tracts may increase and the average number of bids per tract may fall. If increased leasing raises the demand for labor and equipment and thus prices for these inputs, then the higher expected costs will mean lower fair market value and lower bids. Bids may also be lower because firms adding tracts to larger lease portfolios will expect smaller gains in total portfolio value than when adding tracts to smaller portfolios.

These consequences understandably raise concerns about meeting the fair market value requirement. This requirement deals with the issue of who benefits from OCS development as opposed to issues that influence how large the benefits will be. Its achievement has been considered in the process of developing the Proposed 5-Year Leasing Program. Lower bids and less intense competition on some tracts will not, in themselves, indicate that the fair market value requirement is not being met.

Prices in competitive markets vary because of changes in supply and demand. Lower prices for real estate or grain, for example, can result from increases in supply because economic conditions make more suppliers willing to sell more goods at lower prices or because natural events like prime growing conditions have increased production. Prices for resources can decrease if the costs of extracting or using then increases. Such decreases in prices do not mean that the lower prices are less than fair market value. Whether or not they are fair market value depends on the structure of competition in the market, not upon the level of prices.

Prices in competitive markets result from the interaction between numerous sellers, and numerous buyers. If competitively determined prices are the standard for determining fair market value, then prices can be greater or less than fair market value if the market is not competitive. In general, prices would tend to be less than fair market value if there were numerous sellers but only one buyer and greater than fair market value if there were numerous buyers and only one seller. This later condition is widely recognized as monopoly. The inefficiencies and inequities caused by the restrictions in supply and higher prices in monopolistic markets are well known. Antitrust laws have been enacted to prevent such conditions from evolving in our economy.

If all OCS mineral rights had been conveyed to individuals and firms decades ago as is the case with most of our land and mineral resources, then ownership of the rights to produce oil and gas on the OCS would change hands in a competitive market involving numerous sellers and numerous buyers. The rate of supply of leases in this market would be determined competitively as in the private real estate and mineral rights markets onshore. The resulting prices would then be regarded as the fair market value of OCS oil and gas leases.

Because the Federal government, through its OCS Leasing Program, sets the rate at which leases are made available to the lease market, the supply of leases is not, in general, the same as would result in such a private market. It is likely, for instance, that the supply of leases in the 1970's fell substantially below the supply a private market would have made available in response to rapidly increasing oil prices. To put this more precisely using the concepts set forth in Appendix 2, as increasing oil prices brought the optimal time for investments in exploration and development for many tracts closer to a given time in the 1970's, transactions would have occurred in a private lease market so that firms willing to invest would have acquired essentially all of the tracts ripe for investment. Given the restrictions on Federal leasing during the 1970's, particularly in frontier areas, it is not likely that leases were made available at a rate sufficient to match this idealized private market.

These monopolistic tendencies of past leasing rates raise the possibility that lease prices were at least somewhat higher as a result. The question now is, what is the effect from the perspective of fair market value of increasing the rate of leasing in order to catch up on the amount of investment in exploration? Lease prices could be held at higher levels by continuing to restrict the availability of leases. Such a policy could result in prices that would be higher than those in a market in which supply is competitively determined. It would, however, be tantamount to exertion of monopoly power by the government. Losses to the economy would result just as they do from private monopolies. It would be very costly to the Nation to exercise the government's monopoly over the supply of OCS leases as the means for assuring receipt of fair market value. Other means are available that are far less costly to the Nation's economy.

The Role of Tract Evaluation

Even at increased leasing rates, the competitive bidding process does much to assure that the bids the government receives represent the value of the leases under the supply and demand conditions at the time of the lease sale. If the OCS lease market is, in large part at least, sufficient to assure receipt of fair market value, then the role of tract evaluation can change. It is no longer necessary to regard tract evaluation as a filter through which all bids must pass so that below-fair-market-value bids can be detected, a costly and essentially impossible role. Instead, tract evaluation can be viewed as a back-up to the market, as a mechanism to deter any tendency for bidders to exploit unusual situations or new conditions by systematically underbidding or colluding. It is very likely that this has been, in fact, the net effect of the existing procedures. Given this view, it is possible to avoid the costly and unnecessary task of estimating the value of each tract that is to be offered. Instead, procedures can be developed for tract evaluation that reduce costs, at least on a per acre leased basis, and focus the Department's efforts in a fashion that adds most effectively to the lease market's capability to assure the government's receipt of fair market value.

It also would appear to be appropriate to consider the effects on Federal lease revenues that result from tract evaluation and bid rejection. One way of considering how the government gains is to regard the tract evaluation/bid rejection process, as a way of establishing the government as an additional bidder. In effect, a bidder must outbid the government in addition to other bidders. Even by evaluating only a sample of tracts, the government increases the expected number of bidders through its own participation. This should raise the expected level of the high bids submitted.

The fundamental concepts for evaluating tract evaluation samples are:

- that collusion and underbidding, if they occur, are most likely to be reflected in the high bids on tracts offering the greatest returns from such strategies;

- that tract evaluation, by establishing the government as, in effect, a potential bidder on each tract, reduces the potential returns from such strategies;

- that the amount of such return and, therefore, the benefits from establishing the government as an additional bidder is not the same on every tract, but depends on observable factors such as the number of bidders, the amount of the high bid, and the contingency payments on the lease; and

- that the largest percentage gain occurs on tracts receiving the fewest bids while the greatest absolute gain occurs on tracts with high value that usually receive at least a moderate number of bids.

Using these concepts, it should be possible to design a cost-effective sample of tracts for evaluation. In designing a cost effective sample, the costs of tract evaluation and bid rejection must be weighed against the gains. Two types of costs are considered. The first is the cost of the evaluation procedure itself. The second is the cost of the delay in resource development that results when a high bid is rejected. The income expected to be generated by the development of the resources of a tract must be discounted to reflect the effects on the productivity of the economy of delaying the availability of valuable resources. The extent of the delay caused by rejection of a bid depends on the timing of the next sale, assuming of course that it will be bid on and leased at that time. By considering how these costs vary with the design of the sample on the one hand, and how the gains vary on the other hand, a cost effective sampling approach can be devised.

In the past, the rejection percentage has not been a policy variable, but has resulted from the relationship between the high bid levels, the methods used to estimate tract values and the bid rejection rules. Historically about 11% of the tracts receiving bids have been rejected. A change in the tract evaluation methods could change the percentage of rejections resulting from the evaluation. The flexibility to adjust the sample design to reflect these changes is another advantage of this approach.

Because both the costs and gains depend on the expected bidding patterns, the sample design can be modified as bidding patterns change. The sample could also be designed to reflect the difference in the lease market for different areas: the patterns of participation and bidding are quite different, for example, for Alaska OCS leases than for those in the Gulf of Mexico. The sample design can be changed to reflect evidence on the adequacy of the lease market in assuring receipt of fair market value. If there is evidence that the market is doing a more than adequate job, the intensity of the sample can be reduced with resulting savings in the costs. Finally, the sample design and the choice of a minimum submissable bid can be based on the same principles and can reflect their combined effects on bidding patterns.

Attachment A

UNITED STATES
DEPARTMENT OF THE INTERIOR
OFFICE OF THE SOLICITOR
WASHINGTON, D.C. 20240

MAR 20 1981

Memorandum

To: Assistant Secretary, Energy & Minerals

From: Acting Associate Solicitor, Energy and Resources

Subject: Use of Alternative Resource Evaluation Methods to Assure Receipt of Fair Market Value for OCS Lease Tracts

This memorandum responds to your request for advice on the legality of using alternative methods of assessing bid adequacy to assure receipt of fair market value for OCS lease tracts. This proposal was number 11 in a jointly prepared memorandum of the Bureau of Land Management and the Geological Survey on streamlining the OCS leasing process. We responded to the first ten proposals in that document by memorandum dated March 17, 1981.

The recommendation was to develop alternative resource evaluation methods to assure fair market value. Acceleration of lease sales, increased sale size, and compression of the time allowed for the sale process as recommended in the joint memorandum are expected to result in an overload of the capacity of GS to conduct resource economic evaluations for each tract offered for sale. Furthermore, alternative bidding systems will permit less reliance on the Government's evaluation. 1/ The following proposal was therefore recommended:

A. Emphasis on postsale rather than presale evaluation in order to save the effort expended on evaluating tracts not receiving bids. Geological maps using selected geologic and geophysical data will be independently prepared. Increased emphasis will be placed on competition to establish fair market value.

B. Limiting the postsale evaluation to tracts receiving less than a competitive number of bids. As a general guideline, tracts with less than three bids would be evaluated. However, tracts with anomalously low bids would be exceptions to this guide.

1/ Current Departmental reliance upon the Average Evaluation of Tract (AEOT) in determining bid adequacy is already a step towards the new proposal. Both take into account what the individual bidders have presumably considered a tract to be worth, although the AEOT does include consideration of GS's tract evaluation.

C. All drainage and development tracts would be evaluated.

D. Increase the minimum acceptable bid and rental payments in order to protect the government from speculative bidding and to encourage diligent exploration.

Resource economic evaluations have been traditionally performed prior to a lease sale to provide a basis, along with competitive indicators, for deciding whether the high bid for an individual tract should be accepted or rejected. The Department considered this necessary as a deterrent against collusion and systematic underbidding and to insure that the government received fair market value for OCS oil and gas leases under the policy first announced in Bureau of Budget Bulletin No. 58-3 (1957) and then incorporated into Bureau of Budget Circular A-25 (1959). These documents expanded the government's policy toward fees beyond that set forth in the Independent Offices Appropriations Act of 1952, 31 U.S.C. § 483a (1976) (IOAA). With the enactment of the OCS Lands Act Amendments, two new provisions also have an effect upon receipt of fair market value. They are sections 8 and 18(a)(4) of the OCS Lands Act, 43 U.S.C. §§ 1335 and 1344 (Supp. II 1978).

In our analysis, there are two distinct fee situations which must be carefully distinguished: (1) charges relating to recovering the costs of providing special benefits or services provided by the government, and (2) receipt of fair market value for the use or sale of federally owned resources or property. The latter is what concerns us here. Although the IOAA clearly addresses the issue of cost recovery, 2/ it does not, by its terms, address the issue of fair market value. It was by Budget Bulletin No. 58-3 (1957) later incorporated into Budget Circular A-25 (1959), that the government extended its fee policies to include both services and the use or disposal of federal resources or property. 3/ Budget Bulletin No. 58-3 reads, in part, as follows:

> The fair market value should be realized from the sale or use of federally owned resources or property. Sound business management principles and comparable commercial practices should be followed so far as practical and feasible. Generally this activity should be revenue producing and should not be based on the recovery of costs alone. Budget Bulletin No. 58-3, supra at 7. See also, Budget Circular A-25 supra at 2.

2/ See Mississippi Power and Light Co. v. N.R.C., 601 F.2d 233 (5th Cir. 1979), cert. denied, 444 U.S. 1102 (1980).

3/ The relevant portions of Budget Bulletin No. 58-3 and Budget Circular A-25 have not been superseded by later amendments. See, Bureau of Budget Circular A-25, Transmittal Memorandum No. 1 (1963) and Office of Management and Budget Circular A-25, Transmittal Memorandum No. 2 (1974).

In commenting upon this distinction, the Public Land Law Review Commission stated:

> At the present time, the combined provisions of Title V of the Independent Offices Appropriations Act of 1952 and Bureau of the Budget Circular A-25 of September 23, 1959 constitute the primary congressional and executive expressions of policy, respectively, concerning user fees and charges . . . . Whereas Congress expressed itself with respect to fees for governmental services, the executive extended fee policies to both services and the use or disposal of resources and property. This latter category, not covered by congressional policy, is subject to fees at fair market value under executive policy. Public Land Law Review Commission Study Report No. 27, User Fees and Charges for Public Lands and Resources at 289 (December 1970).

The IOAA does not, therefore, apply directly to the present issue. 4/ It was the executive policy of assuring receipt of fair market value for disposal of all federal resources which controlled prior to the OCS Lands Act Amendments. This policy did not require the present system of resource economic evaluations. It provided general guidance only. It was not until the enactment of the Amendments, that Congress established a specific policy for assuring fair market value for disposal of oil and gas resources on the OCS. The OCS Lands Act Amendments added two new provisions which bear upon this problem. 5/ Section 18(a) reads, in part, as follows:

> The Secretary . . . shall prepare and periodically revise, and maintain an oil and gas leasing program

---

4/ Due to the past confusion over the proper interpretation of the IOAA, it is arguable that it now applies to the fair market value question as a matter of administrative practice. Even if it does apply, the statute states that the Secretary may take into account costs to the government and the public policy or interest served in determining a price which is fair and equitable in a manner similar to that of the OCS Lands Act Amendments (see discussion, infra).

5/ Section 2(o) of OCSLA, 43 U.S.C. § 1331(o), gives a definition of "fair market value." This definition, however, applies to the value of "any mineral" and not to the value of lands leased and rights conveyed. The Conference Report states that the term as defined "is only used in this act in relation to the purchase and distribution of oil and gas under Section 27." H.R. Rep. No. 1474, 95th Cong., 2d Sess. 79 (1978). Section 27 pertains to federal purchase and disposition of royalty oil and gas in kind. 43 U.S.C. § 1353. "Fair market value" as it applies to lands leased and rights conveyed is thus not explicitly defined by OCSLA.

> to implement the policies of this Act . . . . Such leasing program shall be prepared and maintained in a manner consistent with the following principles:
>
> *　　　　*　　　　*
>
> (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. 43 U.S.C. § 1344(a).

Section 18 as a whole addresses the establishment of a 5-year OCS leasing program. It does not speak to the specifics of lease sales or of the bidding process which is set forth in section 8 of the OCS Lands Act. Section 18(a)(4) requires that the program be prepared and maintained in a manner to assure receipt of fair market value. This requires the Secretary to guard against scheduling lease sales in a manner so that their size, timing or location would make receipt of fair market value impossible. For example, since bidders on OCS tracts must gather data, prepare bids and be ready to conduct exploration efforts, sale timing could limit those able to participate, thus hampering competition and the receipt of fair market value. Also, if sale offerings were too rapid or made on very short notice, competition could be hampered because of industry's inability to budget or plan for offshore operations. 6/

Section 18(a)(4) speaks to more than just the preparation of a leasing schedule, though. It includes the general term "leasing activities" which, of course, includes bidding by prospective lessees and the acceptance of bids by the Secretary. Nevertheless, section 18(a)(4) is not all that Congress enacted on this subject. The primary policies assuring receipt of fair market value are established by section 8 which governs the award of leases. These policies include the competitive bidding process, the antitrust reviews of lease awards and regulations by the Attorney General in consultation with the Federal Trade Commission, and the development, testing and implementation of bidding systems by the Departments of the Interior and Energy. 43 U.S.C. § 1335. Congress specifically addressed bidding and the acceptance of bids in section (8)(a)(1) which reads, in part, as follows:

> The Secretary is authorized to grant to the highest responsible qualified bidder or bidders by competitive bidding, under regulations promulgated in advance, any oil and gas lease on submerged lands of the outer Continental Shelf . . . . 43 U.S.C. § 1335(a)(1).

6/ For a general review of the effect of size, timing and location of lease sales on fair market value please see the paper entitled "Assuring Receipt of a 'Fair Market Value'" attached at Tab C-2 to the memorandum of the Deputy Assistant Secretary, Policy, Budget and Administration to the Secretary, dated March 19, 1981, concerning the 5-year program.

Section 8 then sets forth the kinds of bidding systems that the Secretary may use. See, e.g., 43 U.S.C. §§ 1335(a)(1)(A) - (H). The Conference Report on the OCS Lands Act describes factors that the Secretary should take into consideration in selecting a bidding system:

> The conferees intend that in utilizing the new bidding alternatives a variety of considerations should be taken into account, including but not limited to: (i) Providing a fair return to the Federal Government; (ii) increasing competition; (iii) assuring competent and safe operations; (iv) avoiding undue speculation; (v) avoiding unnecessary delays in exploration, development, and production; (vii) developing new oil and gas resources in an efficient and timely manner; and (viii) limiting administrative burdens on government and industry. H.R. Rep. No. 1474, 95th Cong., 2d Sess. 92 (1978).

As this legislative history reveals, factors such as avoiding delays and limiting administrative burdens on government and industry are relevant to the Secretary's management of bidding for OCS leases. 7/ While the above quotation cites considerations to be used in selecting a bidding system, we think that they may also be used by the Secretary in determining the adequacy of bids under any bidding system. For example, a decision whether or not to adopt the new proposal would require the Secretary to balance the risk of not receiving what he otherwise might have for a specific tract under the current system against the value of reduced administrative costs and the public interest of earlier production. This is precisely the same risk that Congress has permitted the Secretary to take in choosing between bidding systems. Id.

The current system of resource economic evaluations is just one means of assuring receipt of fair market value. Section 8(a) gives the Secretary discretion to use other practices so long as receipt of fair market is assured. The new proposal is one such alternative. Reliance on the high bid where there are a competitive number of bids on a tract would eliminate the tremendous amount of time and resources expended by the GS in its tract evaluation process. These savings are consistent with the factors that the Secretarty may take into consideration under section

---

7/ The term "fair market value" or other similar terms never exist in a vacuum in either OCSLA or its 1978 amendments. Fair market value is always to be considered in light of, or balanced with, other factors. See sections 101(7) and 102(2) of the Outer Continental Shelf Lands Act Amendments of 1978, 43 U.S.C. § 1801(7) and 1802(2) (Supp. II 1978); section 18(a)(1)-(4) of OCSLA, 43 U.S.C. § 1344(a)(1)-(4); H.R. Rep. No. 1474, 95th Cong., 2d Sess. 92 (1978) (analyzing section 8 of the OCSLA, 43 U.S.C. § 1335).

8(a). Furthermore, if the recommendation is adopted, we suggest a system of random post sale evaluations of competively bid tracts to insure a continuing deterrent against collusive bidding and systematic underbidding.

Finally, we point out that the current system of tract evaluations prior to lease sale and the use of these tract evaluations to support the rejection of bids determined to be insufficient has been repeatedly upheld by the courts. See, e.g., Chevron Oil Co. v. Andrus, 588 F.2d 1383 (5th Cir. 1979); Kerr McGee v. Morton, 527 F.2d 838 (D.C. Cir. 1975). This judicial seal of approval does not, however, preclude the Secretary from implementing a new system for assuring receipt of fair market value consistent with applicable statutes. 8/ Moreover, the foregoing cases can be used as support for a new system. For example, the Chevron case stands for the propositions that the Department must follow whatever regulations it has established concerning bid rejections and that it must have a reasoned basis for its actions. Any new system should accordingly be implemented by regulation and its principles should be based upon sound policy.

If you have any further questions on these recommendations, please do not hesitate to contact our office.

W. P. Elliott Jr.

W. P. Elliott, Jr.
Acting Associate Solicitor,
Energy and Resources

cc: Assistant Secretary, Policy, Budget and Administration
Assistant Secretary, Land and Water Resources
Assistant Secretary, Energy and Minerals
Director, Bureau of Land Management
Director, U.S. Geological Survey

8/ In fact, OCSLA contains no specific method for determining the adequacy of bids. It speaks only of sale "to the highest responsible qualified bidder or bidders by competitive bidding . . . ." 43 U.S.C. § 1335(a)(1).

Attachment B

UNITED STATES
DEPARTMENT OF THE INTERIOR
OFFICE OF THE SOLICITOR
WASHINGTON, D.C. 20240

MAY 11 1981

Memorandum

To: Under Secretary

From: Solicitor

Subject: Further Legal Guidance on Assuring Receipt of Fair Market Value For OCS Leases

This memorandum has been prepared as part of a joint economic and legal analysis by the Office of Policy Analysis and the Solicitor on alternative ways of assuring fair market value as requested in your memorandum dated March 27, 1981. The Solicitor's Office recently issued a memorandum which concluded that the current system of presale OCS tract evaluations by the Geological Survey (GS) is not the only method available to assure receipt of fair market value by the federal government for OCS oil and gas leases as required by the OCS Lands Act, 43 U.S.C. §§ 1331 et seq. (Supp. II 1978). See Memorandum to the Assistant Secretary, Energy and Minerals from the Acting Associate Solicitor, Division of Energy and Resources dated March 20, 1981 at 5. This memorandum will set forth certain guidelines to be followed in choosing a method of assuring fair market value and will examine those alternatives set forth in the paper entitled "Assuring Receipt of a 'Fair Market Value'" which accompanied the memorandum of the Deputy Assistant Secretary, PBA, to the Secretary dated March 19, 1981, concerning the 5-year OCS program. It will also examine the approach developed by GS in a memorandum dated April 23, 1981.

The first step is to examine the requirements of the statute. Section 8(a)(1) of the OCS Lands Act authorizes the granting of leases only to "the highest responsible qualified bidder or bidders by competitive bidding." 43 U.S.C. § 1335(a)(1). Hence fair market value must be assured through some system involving competitive bidding rather than, for example, a lottery with sale at an appraised price. Competitive bidding does not require more than one bid on a tract, but only that all bidders have been given an opportunity to bid. Tipperary Land and Exploration Corp., 79 I.D. 596, 7 IBLA 270 (1972).

Furthermore, bidders must be "qualified." Bidder qualifications are set forth at 43 C.F.R. 3316.1(b). These are not proposed to be changed under any alternative system for assuring fair market value discussed in this paper. Section 8(a)(1) also requires that competitive bidding be conducted "under regulations promulgated in advance." 43 U.S.C. § 1335(a)(1). Any system developed for the rejection of bids to assure fair market value should be established by regulation. This benefits bidders by informing them in advance how the Department will analyze their bids, thus assisting them in determining bid strategy. Accordingly, we do not see issuance of regulations on this point as constituting a regulatory burden.

Section 8(a)(1) continues as follows:

> Such regulations may provide for the deposit of cash bids in an interest-bearing account until the Secretary announces his decision on whether to accept the bids, with the interest earned thereon to be paid to the Treasury as to bids that are accepted and to the unsuccessful bidders as to bids that are rejected . . . . 43 U.S.C. § 1335(a)(1).

The term "whether to accept bids" clearly indicates that the Secretary has discretion whether or not to accept a high bid on a particular tract. It is not simply a ministerial act of issuing a lease to the highest bidder. This decision "whether to accept the bids" also provides an opportunity to determine the qualifications of bidders and to assure receipt of fair market value. Finally for our current purpose, section 8(a)(1) requires sealed bids. Hence auction bidding is not authorized. Id. Any system devised to assure receipt of fair market value must be consistent with these factors.

The OCS Lands Act does not contain an applicable definition of fair market value. 1/ Fair market value does, however, have a definite legal meaning as developed through the common law, generally in the context of condemnation of real property under the government's power of eminent domain. Fair market value is the amount at which property would change hands between a willing buyer and a willing seller, neither being under any

---

1/ Section 2(o) of OCSLA, 43 U.S.C. § 1331(o), gives a definition of "fair market value." This definition, however, applies to the value of "any mineral" and not to the value of lands leased and rights conveyed. The Conference Report states that the term as defined "is only used in this act in relation to the purchase and distribution of oil and gas under Section 27." H.R. Rep. No. 1474, 95th Cong., 2d Sess. 79 (1978). Section 27 pertains to federal purchase and disposition of royalty oil and gas in kind. 43 U.S.C. § 1353. "Fair market value" as it applies to lands leased and rights conveyed is thus not explicitly defined by OCSLA.

compulsion to buy or sell and both having reasonable knowledge of the relevant facts. State Commissioner of Transportation v. Copper Alloy Corp., 136 N. J. Super. 560, 347 A. 2d 365 (1975); Arkansas State Highway Commission v. De Laughter, 250 Ark. 990, 468 S.W. 2d 242 (1971). Since the seller is under no compulsion to sell, this implies that he is not required to sell to anyone for less than he can get from another. Furthermore since both parties must have reasonable knowledge of relevant facts, this implies that neither party is tricked or cheated in the transaction by collusion or deceit.

In the past, the Department has performed resource economic evaluations prior to lease sales to identify high bids which were below fair market value. This practice has been repeatedly upheld by the courts. See, e.g. Chevron Oil Co. v. Andrus, 588 F.2d 1383 (5th Cir. 1979); Kerr McGee v. Morton, 527 F.2d 838 (D.C. Cir. 1975). This approach has also acted as a deterrent against collusion and systematic underbidding because bidders realize that they must also "outbid" GS evaluators. Consequently, the current practice has served the function of maintaining a fair market. Unfortunately, this practice is now proving to be too expensive in terms of both money and manpower for application to recent policy proposals to accelerate the leasing of OCS tracts. Another approach to the problem is to assure that bids are made in a market which is sufficiently fair. It relies on competition to eliminate the effects of collusion and systematic underbidding. The problem then becomes one of assuring a level of competition sufficient to eliminate these factors. Variations on our traditional practice of presale evaluations and the concept of determining prices in a competitive market form the basis for several options set forth in PBA's paper entitled "Assuring Receipt of 'Fair Market Value'." We now examine those options.

A. Presale evaluation of a Random sample of tracts to be offered.

It is expected that presale evaluation of a random sample of tracts would have the same deterrent effect against collusion and systematic underbidding as the current practice since bidders would be unable to predict which tracts would be evaluated and would still be concerned with "outbidding" GS. We see no legal problems with this approach. Its similarity to the current system allows us to assert the legal precedents supporting that system. See, Chevron Oil, supra. The random selection of tracts poses no problem. Use of random sampling procedures in other contexts, such as by the Internal Revenue Service, has been upheld by the courts. See, e.g., United States v. Flagg, 634 F.2d 1087 (8th Cir. 1980). There also appears to be no legal constraint on choice of sample size or distributions of sampling. This approach still suffers the problem of wasted Departmental resources to the extent that evaluated tracts receive no bids. This problem would be exacerbated if the Department adopts the proposed streamlining procedure of offering entire geologic basins.

B. Targeted postsale tract evaluation focused on few-bid tracts.

This option focuses on evaluating few-bid tracts, avoiding the cost of presale evaluations of tracts which may subsequently receive no bids and relying on competition shown on many-bid tracts to give confidence of receipt of fair market value.

The Department currently relies to some extent on competitive indicators in assessing bid adequacy. The Average Evaluation of Tract (AEOT) is an example. As set forth in the memorandum of the Acting Associate Solicitor, Energy and Resources, supra, competitive indicators are a valid method of assuring receipt of fair market value under OCSLA. The danger we see here is "noise" bids, bids which are anamolously low to give the appearance that there is ample competition for a tract. This problem may be solved or reduced by applying BLM's existing criteria on "noise" bids. It may also be solved or reduced by raising the minimum price per acre for cash bonus bidding. There are no statutory or regulatory restrictions on the Secretary's discretion to set such a minimum price. Existing case law would support the rejection of bids which were found to be inadequate. A problem arises with possible prejudice, or at least the appearance of prejudice, of postsale evaluations when the bid amounts are already known. Although we do not feel that this arises to the level of a legal objection, policymakers should be aware that GS may have to respond to this kind of criticism from a rejected high bidder. We recommend that firm guidelines be established preventing as much as possible contact or even the appearance of contact between bidders and those GS employees actually making the evaluations for a particular sale.

C. Bid rejection rules without tract value estimates.

This option would automatically reject a specified percentage of high bids, with a higher percentage of few-bid tracts being rejected to reflect competitiveness. No evaluations of any tracts would be performed. The problem with this option is that it is just as likely to result in rejection of bids reflecting fair market value within a given class (i.e., one bid tracts, two bid tracts) as it is to result in rejection of those bids which do not. There is no way to distinguish between the two. Without actual evaluations, this option could be attacked on grounds that it resulted in rejections which were arbitrary and capricious, and which had no basis in fact. Moreover, without evaluations it does not appear that our existing legal precedents could support it. 2/ This option also is subject to "noise" bids, but this could be handled as described above. Finally, it was suggested that the specifics of bid rejection rules for this option be kept confidential until bids are submitted. This could be subject to attack on grounds that the rules were intentionally designed to be prejudicial to certain bidders and that the rules were not set forth in regulations as required by section 8(a)(1) of the OCSLA.

D. Fair market value determination followed by acceptance of all bids.

This option places complete trust in the competitive market. If the market based upon study of competition is declared a fair one, then all high bids would be accepted. Our first observation is that a back up system must be chosen and be readily available since the competitive nature of the market may change from sale to sale depending upon many factors, including the size, timing, and location of lease sales and external forces such as supply and demand for petroleum products and the international political climate.

Second, each sale would be subject to a separate analysis and, therefore, a separate attack upon the Department's basis for declaring a fair market. Rather than a disgruntled bidder attacking a bid rejection in court, whole sales could be subjected to legal challenge. Even when we win such suits, they often result in delayed sales costing the government millions in loss of present value. If competitive markets assuring fair market value are believed to exist perhaps the best approach is to simply reduce the number of random or targeted tracts evaluated under systems A and B above.

E. Proposal of Geological Survey

Finally, by memorandum dated April 23, 1981, GS has developed its own alternative resource evaluation methods. It recommends the following:

1. Emphasizing postsale rather than presale evaluation in order to save the effort expended on evaluating tracts not receiving bids.

2/ We would similarly object to other alternatives that did not use actual tract evaluations as the basis for bid rejection decisions, such as a system rejecting a certain percentage of bids based upon historical data.

2. Limiting the postsale evaluation to tracts receiving less than a certain number of bids. As a general guideline, tracts with less than three bids will be evaluated. However, tracts with anomalously low bids will be exceptions to this guide.

3. Providing for random postsale evaluations of tracts receiving three or more bids to insure a continuing deterrent against collusive bidding and systematic underbidding.

4. Evaluating of all drainage, development, and proven tracts.

5. Increasing the minimum acceptable bid and rental payments in order to protect the Government from speculative bidding and to encourage diligent exploration.

This is essentially the proposal which was analyzed and approved in the March 20, 1981, memorandum of the Acting Associate Solicitor, Energy and Resources. As stated earlier, there is no legal problem with random selection of tracts for evaluation. See, e.g., United States v. Flagg, supra. The proposal does have the problem of "noise" bids, but this is reduced by the provision to increase the minimum acceptable bid and can be reduced further by applying BLM's "noise" criteria. Since bids will be opened before evaluations are conducted, this proposal shares with targeted postsale evaluations (see B above) the problem of charges of prejudicial evaluations by rejected bidders. This is only a matter for sensitivity and is not a legal constraint, but we would recommend that guidelines be established preventing contact or the appearance of contact between bidders and evaluators as described earlier. An important factor in this proposal is that any rejection of a high bid will be based upon an actual evaluation. This allows us to rely on existing precedents in bid rejection litigation.

Finally, GS recommends evaluating all drainage, development and proven tracts. (See p. 5 of GS's proposal for definitions of these tracts). This is important from a competitive standpoint because one bidder, usually a lessee on an adjacent tract, will always have better information than other bidders about the potential of these tracts. This "inside" information, although perfectly legal for a bidder to use in planning his bidding strategy, puts other bidders at a disadvantage. They are forced to bid with greater risk thus, given common bidding strategies, are likely to bid lower. Knowing this, the bidder with "inside" information need not bid as high to win the tracts. Postsale evaluations, therefore, help to assure fair market value since the bidder will still have to "outbid" GS who has the same information.

Conclusion

After evaluating all of the foregoing proposals we conclude that any system adopted should be consistent with the following:

1. Rejections of high bids should be based upon actual tract evaluations;

2. Presale or postsale evaluations may be used;

3. Use of competition to assure fair market value and to serve as a basis for acceptance of high bids should provide for elimination of the effects of "noise" bids through use of BLM's "noise" criteria or by increasing the minimum acceptable bid, or both; and

4. Random selection of tracts for evaluation may be used.

Moody R. Tidwell
DEPUTY SOLICITOR

cc: Assistant Secretary, Policy, Budget and Administration
Assistant Secretary, Energy and Minerals
Assistant Secretary, Land and Water Resources

APPENDIX 4

Appendix 4

Availability of Transportation Networks to Bring Oil and Gas to Market

The transportation issue can be divided into two parts--bringing the resources to shore, and then transporting the landed resources to refinery and demand centers. Both lower 48 and Alaskan transportation networks have been reviewed, including a discussion of the ability of refineries to handle additional supplies of sour crude. The Department of Energy (DOE) 1/ and industry respondents to the October 26, 1978, request for information provided the initial basis for assessing this issue. An update based on more current expectations was then included.

In general, it is not the availability of transportation systems at present, but the cost of establishing and operating them to bring new discoveries to market which is the focus of analysis. Transportation costs are appropriately considered in estimating the net economic value of oil and gas in each OCS planning area.

The question of transportation is closely related to consideration of the location of OCS areas and their resources with respect to regional and national energy markets. In fact, because of modern transportation systems, oil and gas can be delivered to any regional market in the United States from any OCS planning area. Because geological events have produced a very uneven geographical distribution of oil and gas, there is a natural "glut" at the point of production. The reduced transportation near such a "glut" makes oil used in nearby markets have a higher net economic value and perhaps a slightly lower price. But it does not

---

1/ Federal Leasing and Outer Continental Shelf Energy Production Goals (Draft) DOE Leasing Policy Development Office, February 1979.

in any way preclude the additional production of resources for distant markets which are not near resources. Such markets are importers of oil and gas and would otherwise be forced to import from abroad at higher costs to the nation.

Bringing the Resources to Shore

1. Lower 48

At present, the Gulf of Mexico is the only OCS area with an extensive pipeline system, including a network of oil and gas gathering systems and trunk lines. In the only other commercially producing OCS area, Southern California, pipelines are generally used to bring the resources ashore, although tankers are often employed to transport the landed resources to refineries.

Offshore oil and gas can be transported to shore either by pipeline, barge or tanker. The decision of whether to use pipelines, barges, or tankers 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. Also judgments need to be made as to what is environmentally preferable and technically and economically feasible.

It is anticipated that production in the central and western Gulf of Mexico will continue to use pipelines, and in many cases, only new gathering lines would be required to connect new areas to existing trunk systems. Construction of new pipelines in the extreme western Gulf of Mexico may be required, as well as for any production in the eastern Gulf of Mexico which has no current production. In the eastern Gulf of Mexico, tankering of oil might be utilized if resources do not economically justify pipelines.

In the Atlantic, the choice between tankers and pipelines will also be made based on the amount of resources to be transported. It is likely that due to distance from shore, any oil production would be tankered from the Blake Plateau in the South Atlantic. Likewise, due to distance from refineries and shore, it is considered likely that oil production from Georges Bank in the North Atlantic would also be tankered.

At present, pipelines are used to bring oil and gas ashore in Santa Barbara Channel, although tankers are often employed to transport landed oil to refineries. Pipelines are considered most desirable in California because of air quality effects of tanker terminal use. Pipeline transport is most likely in the Santa Barbara Channel and other portions of Southern California, due to the relative concentration of resources and existing refining infrastructures. This is also the area where air emissions are of greatest concern. Pipelines are also possible in central California in the Santa Maria area. However, tankering of oil may occur in northern California. In general, for the lower 48, production from OCS areas is not expected to pose any major transportation difficulties.

2. Alaska

The following is a discussion of transporting Alaskan oil and gas to shore, and then transporting these resources to the lower 48.

The only offshore oil and gas production in Alaska has been in State waters in Upper Cook Inlet. There is a local system of pipelines connecting these operations with refineries and tanker terminals at Drift River and Nikiski. There is also a 12-inch diameter gas pipeline extending from the Kenai Field to Anchorage. In addition, there is a liquified natural gas (LNG) terminal at Nikiski from which LNG is presently shipped to Japan.

The Trans-Alaskan Pipeline System (TAPS) began transporting crude oil from the Alaskan North Slope (ANS) to Valdez on June 10, 1977. The crude reached Valdez on July 28 and the first tanker departed on August 1. TAPS is a 48-inch diameter line designed to have a potential capacity of 2.0 million barrels per day. In 1981, it was able to deliver 1.5 million barrels per day by crossing an 800 mile route from Prudhoe Bay to an ice free area terminal at Valdez. The terminal 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 with an estimated 9.6 billion barrels of recoverable oil and Kuparuk with an estimated 1.2 to 1.5 billion barrels of recoverable oil. As of the end of 1981, nearly 2 billion barrels of oil have been handled by TAPS. The total Alaska crude oil delivered to lower 48 States is about 1.6 million barrels per day. This level includes 88,000 barrels per day of southern Alaska production which is not expected to expand significantly through the early 1980's. Southern Alaskan Production has been as high as 190,000 barrels per day; however, production has declined over recent years.

With regard to future OCS development, Beaufort Sea OCS operations conceivably could use TAPS to transport crude oil to the lower 48. An analysis of transportation constraints for this area must integrate Alaska North Slope (ANS) and National Petroleum Reserve in Alaska (NPRA) production plans with projected OCS production. Although a number of studies have projected different levels and schedules of ANS production, total production from the Prudhoe Bay, Kuparuk, and possibly Lisburne fields, is likely to peak during the mid-1980's and to decline thereafter. OCS crude could be accommodated in TAPS if there were a decline in ANS crude or if TAPS were expanded to 2.0 million.

The U. S. Maritime Administration estimates that 4.5 million deadweight tons (DWT) of large tankers will be required to transport 1.75 million barrels per day of ANS and South Alaska crude to the lower 48 in the early 1980's. This volume could drop to 4.1 million DWT by 1985, if onshore pipelines to transport west coast crudes to refining centers in PAD Districts II and III are established. (Map of PAD Districts attached.) There is expected to be 4.8 million DWT of non-subsidy large tankers and 1.5 million DWT of subsidy tankers available by the end of 1982. Therefore, there should be no tanker constraints to transporting Alaskan OCS crude by TAPS in the late late 1980's.

The transportation of Alaskan OCS natural gas from the Prudhoe Bay area to the contiguous U.S. could be accommodated by the Alaskan Natural Gas Transportation System. This system as proposed would have the capacity to transport 2.0 billion cubic feet of gas per day (bcfd) by the late 1980s and 2.4 bcfd in the early 1990's. By installation of intermediate compressor stations, the system could be increased to 3.2 bcfd. The system capacity could be further increased by addition to the compressor horsepower at each station.

Recently, Congress has passed legislation to encourage the financing and eventual construction of the Alaska Natural Gas Transportation System. However, there is still no guarantee that the estimated $43 billion project will be undertaken. In the absence of the pipeline being built, industry has the option of reinjecting gas when it enhances oil recovery or is not competitive. Liquefaction or conversion of gas to methanol, for example, may be a feasible way to transport gas from Alaska to demand centers.

Industry indicates that the technology exists to locate an LNG or methanol terminal in Northern Alaska and then use a grounded barge with prefabricated facilities for processing, storage, and utilities. The major problem lies in operating tankers in an ice environment. In relatively ice-free areas, such as in the southern Bering Sea, maneuvering, docking and loading tankers should not be a problem. LNG terminals could be mounted on a platform. 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 tanker is available but has not been proven.

The transportation of crude oil from OCS operations in the Bering Sea and the Gulf of Alaska, Kodiak, and South Aleutian Shelf 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. Supply of tankers should not pose a constraint in this time period.

For the Gulf of Alaska and Kodiak areas, oil could be transported by pipeline to shore and by tanker to demand areas, with offshore storage and loading in selected cases. For the Bristol Basin, there would be a pipeline to the south side of the Aleutians for tanker shipment to demand areas. For the St. George Basin, there would be either offshore storage and loading on tankers to demand areas or for very high production rates, a pipeline to the Aleutians for tanker shipment to demand areas. Oil found on the Navarin Basin would be loaded offshore to ice-breaking tankers; storage would take place either offshore or on an island. Engineering designs for remote offshore loading and storage terminals still need further refinement. Oil found in the Norton Basin and in Hope Basin would be sent by pipeline to shore for storage and by an ice-breaking tanker to demand areas, with a possible tanker transshipment point from an ice-breaking tanker to a normal tanker in Southern Alaska.

As discussed above, OCS operations in the Beaufort Sea should be able to use the TAPS and Alaskan Natural Gas Transportation System. If this is the case, transportation from the Beaufort Sea OCS area should not pose a major constraint, since production would not begin before the late 1980's.

To deliver crude oil from the northwestern Alaska OCS provinces, two major alternatives could be considered—construction of an east-west pipeline from Naokok to the TAPS line, or construction of a north-south pipeline from Naokok to Cape Darby. The former alternative would provide a means for transporting NPRA resources as well as OCS resources, and would have the advantage of making use of presently operating systems. The latter alternative would require the construction of tanker facilities at Cape Darby.

With regard to the ice-breaking tanker alternative, there presently are no marine vessels capable of operating year-round in the Arctic. However, analyses have been conducted on the problem of transporting resources through the Arctic Islands to markets in eastern United States and Canada. Three companies—Dome Petroleum, Ltd., Globetic, and Seatrain Lines, Inc.—have been studying systems to transport crude oil from the area via ice-breaker tankers. All three companies have submitted statements to DOE outlining proposals for the use of such tankers to move ANS crude to the east coast by way of the Northwest Passage.

DOE's conclusions concerning transportation constraints are as follows: In the south Alaskan OCS provinces some delays may be experienced due to the need to construct tanker facilities, although conventional tankers can probably be used.

In the Beaufort Sea OCS, it may be possible to make use of TAPS and the Alaska Natural Gas Transportation System should it be built, provided that pipeline systems to deliver the offshore resource to Prudhoe Bay can be developed in a timely fashion. For the other OCS areas in northern and western Alaska, transportation of OCS resources would require the construction of new onshore pipelines, or development of ice-breaking tankers and tanker facilities. Little analysis has been performed up to this time on the feasibility and costs of new onshore pipelines. There are a number of proposals to use icebreakers in the northern Canadian provinces, and any use of such vessals would provide experience during the 1980's.

Disposition of Additional Supplies of Sour Crude

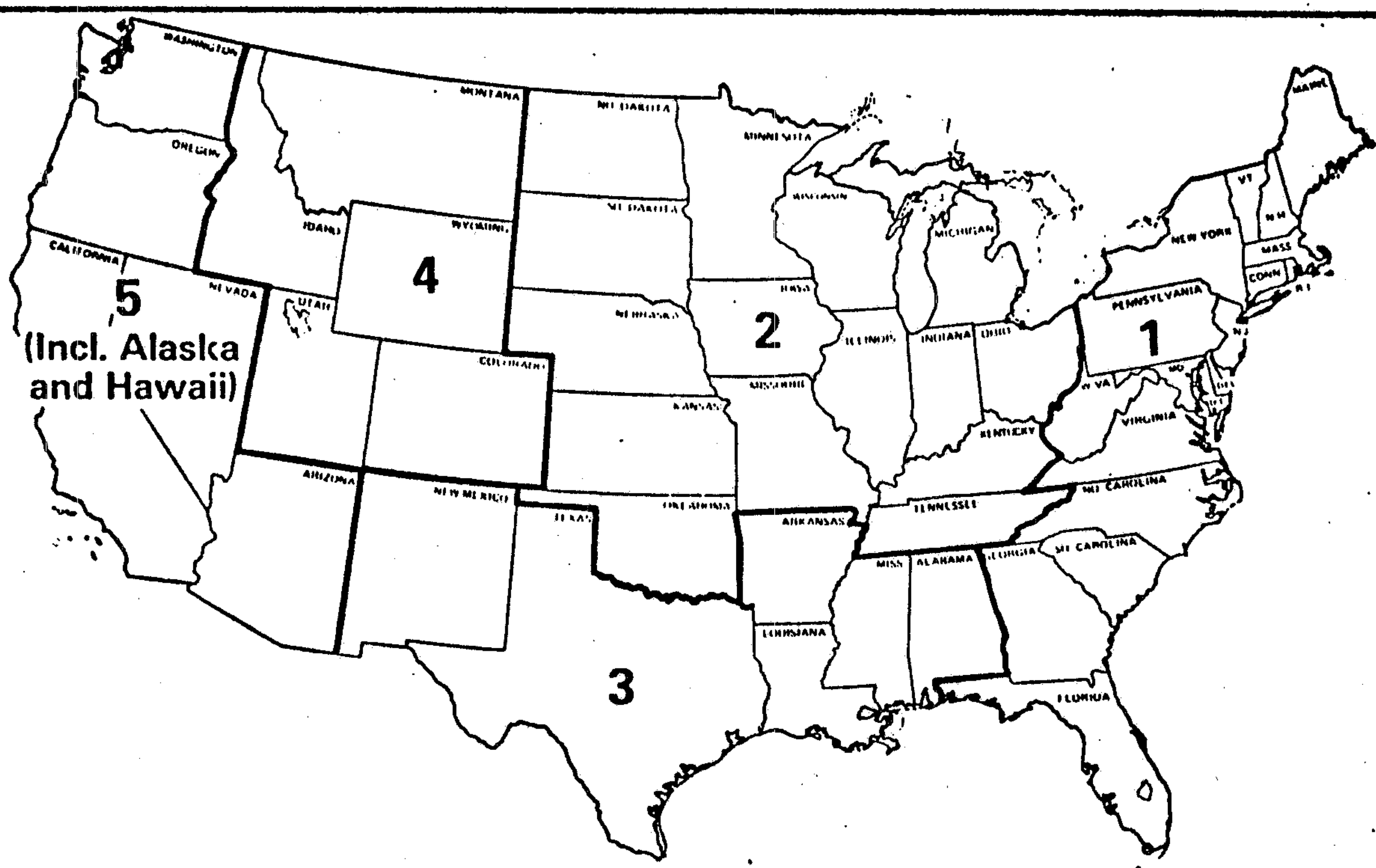
Once supplies reach the lower 48, the question that remains is how will they be transported to refineries capable of handling the sour crude produced. Any sweet crude found could back out west coast imports, whereas, sour crude would need to be transported to either Gulf Coast or mid-west refineries. There is a deficit in refinery capacity to process sour crude on the west coast. The type of crude found in the California OCS and in the Northern Alaskan OCS regions has not been determined, but is expected to be sour. Thus, contingencies for sour crude supplies must be reviewed.

The following analysis of refinery capacity and possible other uses of sour crude supplies has utilized data obtained from the Department of Energy's Energy Information Administration. In considering petroleum refining capacity as a possible constraint to the processing of future OCS crude oil, it is necessary to examine the locations, total capacities and compatibility of these capacities with the OCS crude characteristics. The ability of refineries to process sour crudes (arbitrarily defined in this analysis as crude oil with a sulfur content greater than 0.5% by weight) is the principal parameter to be examined.

Assuming 90 percent refining capacity usage as the maximum practical limit (based on historical usage), refineries operated very close to full capacity in 1981. A significant amount of this capacity was used to refine imported crudes. A total of about 4.2 million of the 12.3 million barrels per day refined during July 1981 was imported. Imports were most significant in PADDs I (Atlantic), II (Mid-West), and III (Gulf), accounting for about 3.5 million barrels per day, or 36 percent of all crude refined in these districts. For this reason, an analysis of refining capacity available for future OCS production must consider the feasibility of substituting this crude for imports.

Total operable capacity is expected to grow from 16.3 million barrels per calendar day in 1981 to 17.6 million barrels per day in 1983. For PADDs I, II, and III, the growth in total operable capacity is expected to be 1.1 million barrels per day. PADD V operable capacity is expected to grow by only about 0.2 million barrels per day between 1981 and 1983.

In analyzing refinery capacity as a potential constraint to future OCS production, it is reasonable to differentiate between capacity on the east coast and Gulf of



1
2
3
4
5
(Incl. Alaska
and Hawaii)
MAINE
VT
N H
MASS
CONN
R I
NEW YORK
PENNSYLVANIA
N J
MD
W VA
VIRGINIA
NO CAROLINA
SO CAROLINA
GEORGIA
FLORIDA
ALABAMA
MISS
TENNESSEE
KENTUCKY
OHIO
INDIANA
ILLINOIS
MICHIGAN
WISCONSIN
MINNESOTA
IOWA
MISSOURI
ARKANSAS
LOUISIANA
NO DAKOTA
SO DAKOTA
NEBRASKA
KANSAS
OKLAHOMA
TEXAS
MONTANA
WYOMING
COLORADO
NEW MEXICO
IDAHO
UTAH
ARIZONA
WASHINGTON
OREGON
NEVADA
CALIFORNIA

Mexico (PADDs I, II, and III) and on the west coast (PADD V). The analysis of PADDs I, II, and III, therefore, pertains principally to OCS production off the Atlantic Coast and the Gulf of Mexico. The analysis for PADD V pertains to OCS production off the Pacific Coast and Alaska.

PADDs I, II, and III: The total operable capacity is expected to grow by 1.1 million barrels per day between 1981 and 1983. Assuming a maximum capacity usage of 90 percent, there is a potential to process an additional 1.0 million barrels per day by 1983. Imported crude presently accounts for about 3.5 million barrels per day of refining capacity, of which about 1.8 million is medium sour to high sulfur. Even under the extremely conservative assumption that all new OCS crude production would be medium to high sulfur, at least 3.1 million barrels per day of this crude (1.1 plus 1.8) could be refined by 1983. Refining capacity does not appear to pose a constraint for these regions in the near future.

PADD V: PADD V operable refining capacity is expected to grow by only about 0.2 million barrels per day between 1981 and 1983. More significantly, there is presently a limit in refining capacity to process sour crude. This problem is potentially relevant to the northern OCS provinces of Alaska and the Pacific Coast provinces since the bulk of estimated resources in these areas may be sour crude. The southern provinces of Alaska contain predominantly sweet crudes and OCS production from these areas can, therefore, be essentially substituted on a one-for-one basis for imported crudes, which presently total about 0.8 million barrels per day.

Crude oil from the ANS began to reach California in large quantities in August 1977 and an ANS production rate of 1.5 million barrels per day was achieved in 1981. Of this amount, an estimated 0.7 million barrels per day was processed by PADD V refineries with the remainder being transported to eastern refineries via the Panama Canal. As of October 1981, the availability of ANS crude had not caused crude oil production to decline appreciably, but it had caused the amounts of imports to drop markedly. For the first ten months of 1981 average imports were down 67.7 percent from 1977 levels. Virtually all of the crude oil still being imported to PADD V is light, and most of it is also sweet.

The present surplus of west coast crude is expected to grow through the early 1980's as new offshore production in California and Alaska becomes available and as production from Naval Petroleum Reserve Number 1 at Elk Hills is marketed. A wide range of estimates has been made by various sources of the amount of surplus expected when additional actions are taken, with the most likely range between 0.6 and 1.3 million barrels per day in 1985. These estimates, made before ANS production actually began, do not reflect the possibility of new transportation and refining capacity to handle the surplus. These possibilities are briefly summarized below:

1. A proposed PacTex project was proposed to move up to 0.7 million barrels per day of ANS crude from Long Beach, California, to Midland, Texas, thereby virtually eliminating the present transshipment of oil through the Panama Canal to PADD III refiners. In early 1979, the PacTex spnsor announced that it was abandoning the project as a result of delays in obtaining permits, as well as anticipated future delays due to pending and prospective litigation. The permitting process was essentially complete at the Federal level and was nearing completion at State and local levels.

2. Another west-to-east pipeline following a northern route was also proposed. By order of the Canadian Government, refiners in the Northern Tier States were to receive reduced amounts of Canadian oil exports. Such a northern pipeline could fulfill three functions:

(a) It could provide crude oil to those refiners in the Northern Tier States which would be affected by the program of crude export curtailment proposed by the Canadian Government.

(b) It could provide crude oil to refiners in the Mid-Continent-Midwest to which pipeline delivery systems are at close to full operating capacity.

(c) It could be used to ship ANS crude oil, surplus to West Coast requirements, to other refining centers more economically than by tanker through the Panama Canal.

To the extent that ANS crude is ever moved through a northern line to the Mid-Continent/Midwest, a substantial volume of foreign crude oil could be "backed out" from the Gulf Coast.

The delivery of crudes from PADD V to PADDs II and III require that timely decisions be made. The Public Utility Regulatory Policies Act of 1978 includes a provision for establishing a process for selecting and expediting issuances of permits for a "northern tier" crude oil transportation system and expediting the issuance of permits for the PacTex project. However, there is still some uncertainty as to whether the Port Angeles terminal site will be acceptable to the State of Washington.

3. ARCO has the ability to transport 0.028 million barrels per day of ANS crude from Long Beach to Four Corners and then to Midland, Texas, via the

Texas-New Mexico pipelines where connections are available to the mid-west and Gulf Coast. ARCO can expand the flow to about 0.15 million barrels per day with increased horsepower. Since the line is fed by tanker deliveries, it will need California's approval to increase delivery.

4. A number of other actions could occur in the early 1980's to offset the remaining surplus. West Coast refiners could rebuild their plants to handle the lower gravity and higher sulfur content of north Alaskan crude. About 60 percent of the refining capacity in PADD V has been able to process sour crude.

Another factor that must be taken into account in assessing the problem is that ANS crude production will eventually decline due to depletion of reserves. Even under the most optimistic projections of production from the Prudhoe Bay, Kuparuk, and Lisburne Pools, production is expected to peak during the mid to late 1980's and to decline thereafter. Any production declines thereafter will free up refining capacity for OCS crudes.

Finally, even if the investments in transportation and refining capacity do not come to pass, reconsideration of present government policy in regard to exports of domestic crude oil is always a possibility. Japan had announced its intentions to diversify sources of petroleum imports and has expressed interst in purchasing ANS crude. Data on Japanese crude purchases indicate that 4.7 to 5.1 million barrels per day were imported in the first half of 1978, of which 1.4 to 1.7 were Saudi light. Since Japanese demand for imports is expected to increase, it is likely that Japan could take as much Alaskan crude as the producers are allowed to sell them without the need for any price discounting. A recent Presidential decision not to export crude oil to Japan for the present has been made.

Any decision to export Alaskan crude would have to be done in compliance with existing legal requirements. Under the Mineral Lands Leasing Act, as amended by the Alaskan Pipeline Act, export of any U. S. domestically-produced oil is not permitted without Presidential authorization subject to congressional veto if at some point it is carried in pipelines over Federal rights-of-way.

In conclusion, refining capacity does not pose a constraint to further OCS production from east coast and Gulf of Mexico provinces. For the Northern Alaskan provinces, there will be a constraint through the early 1980's. However, most production resulting from sales over the next five years are likely not to occur until at least the late 1980's. In addition, the possibility of building greater transportation capacity to deliver crude oil from the west coast to PADDs II and III should economic incentives improve, additional availability of refining capacity in PADD V due to reconfiguration of refineries, and reduction in ANS runs during the mid to late 1980's, and the possibility of reconsidering government policy at that time in regard to exports of domestic crudes can resolve this problem.

APPENDIX 5

Interest of Potential Oil and Gas Producers

On December 31, 1980, the Department of the Interior published a notice in the Federal Register requesting comments on the possible revision or reapproval of the 5-Year OCS oil and gas leasing program. This notice requested, inter alia, ranking of each planning area by oil and gas potential and by interest in exploration and development. The planning areas are shown in the maps in Figures 1 and 2.

Fifteen letters were received from industry in response to this Federal Register notice. Five companies responded specifically to this request. The aggregate of this ranking is shown on table 1. Only two companies ranked areas by interest in exploration and development. We believe this response level is too small to provide a valid ranking.

Three companies provided a numerical ranking of all 19 planning areas, one through nineteen. One company ranked areas "very high," "high," "moderate" and "low." The fifth company ranked areas "high," medium" and "low." These rankings were converted to a common ranking system to develop the consolidated ranking list.

Since the December 31, 1980, notice was published, the boundaries of some of the OCS planning areas have been changed. These changes, which are shown in Figures 3 and 4, make it impossible to apply the industry ranking consistently to areas included in the proposed 5-Year Program.

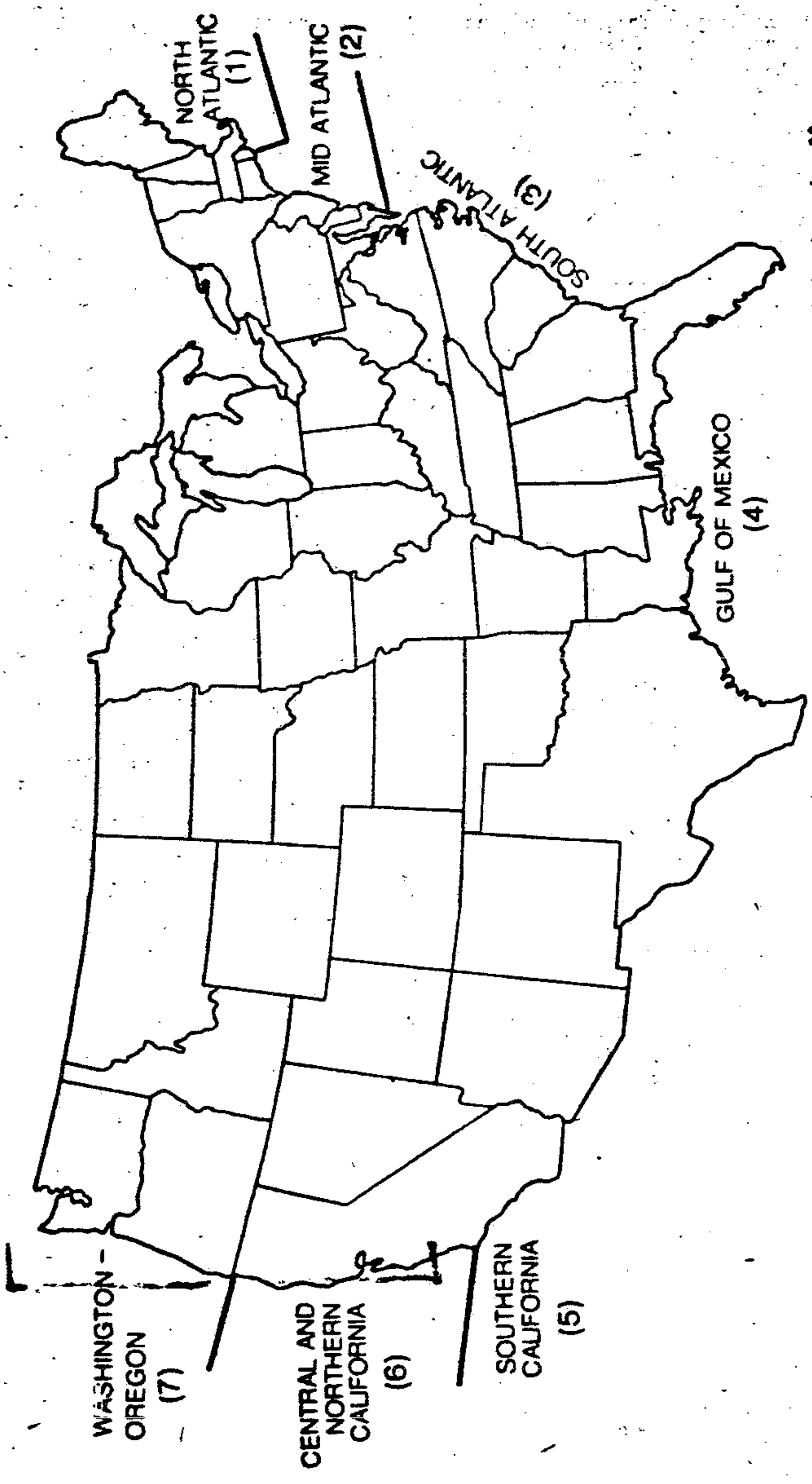
Other comments received in response to the December 31, 1980 Federal Register notice which provide an indication of industry interest are summarized in table 2. Twenty-seven letters from industry were received on the draft proposed program, which was published in the Federal Register on April 17, 1981. Four of these responses provided an indication of industry interest in specific areas. These responses are also summarized in table 2. None of the industry comments on the July 24, 1981, proposed program provided new information on areas of interest.

Table 1

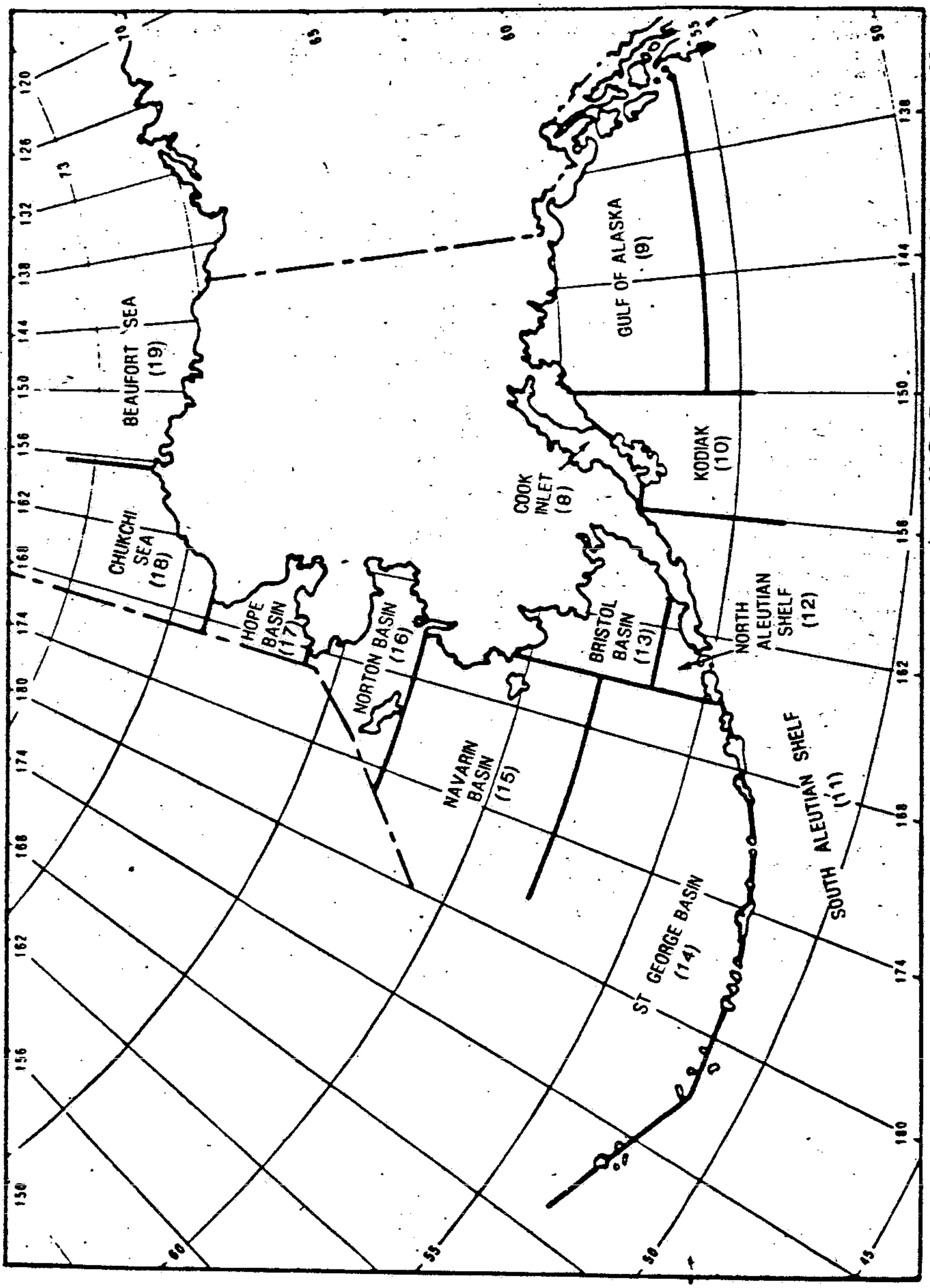
Industry Ranking of Resource Potential

January-February 1981

1. Beaufort Sea
2. Gulf of Mexico
3. Chukchi Sea
4. Navarin Basin
5. Southern California
6. St. George Basin
7. Central and Northern California
8. North Atlantic
9. Norton Basin
10. Bristol Bay
11. North Aleutian Shelf
12. Mid-Atlantic
13. South Atlantic
14. Gulf of Alaska
15. Hope Basin
16. Cook Inlet
17. Washington-Oregon
18. Kodiak
19. South Aleutian Shelf



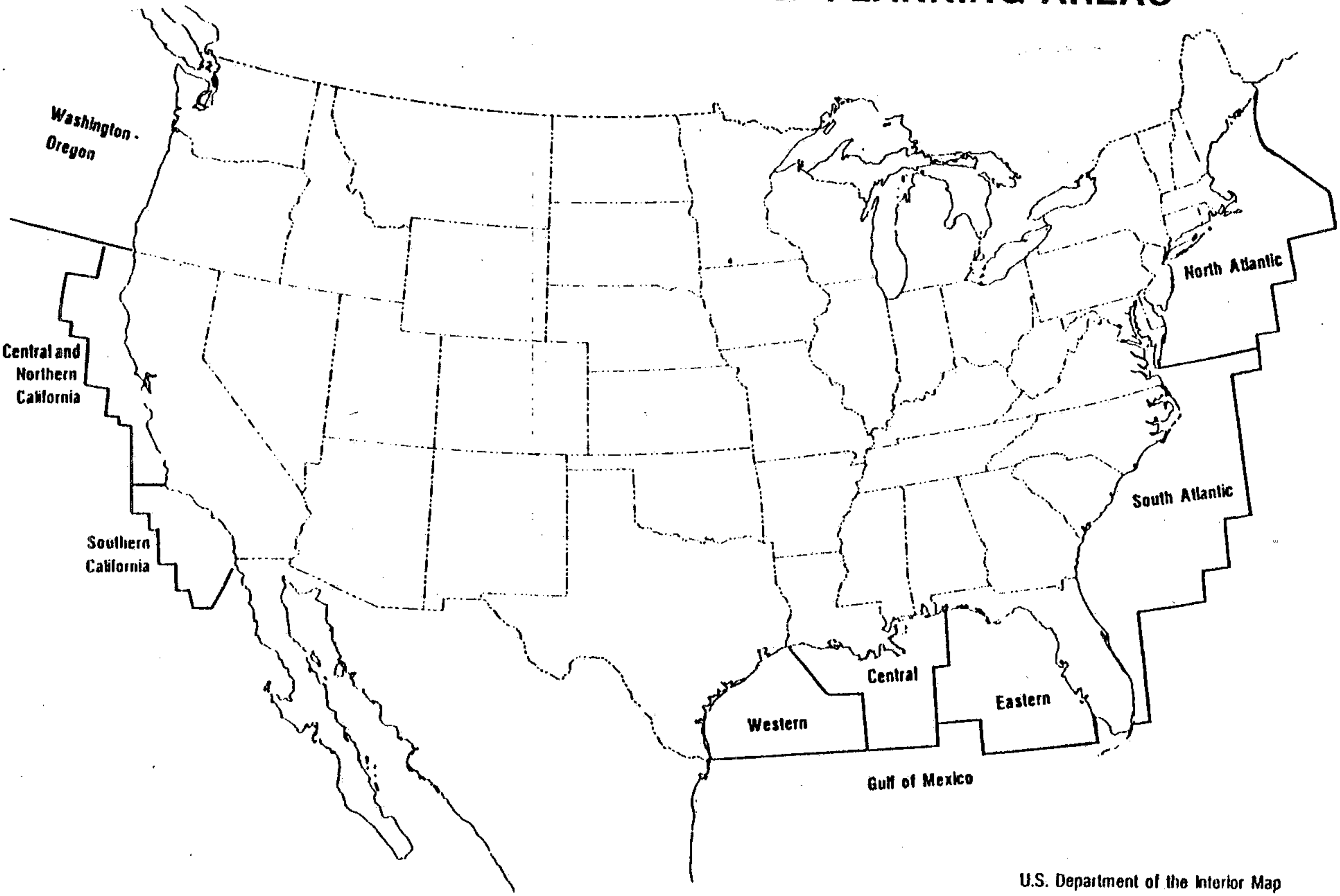
U.S. Department of the Interior Map



U.S. Department of the Interior Map

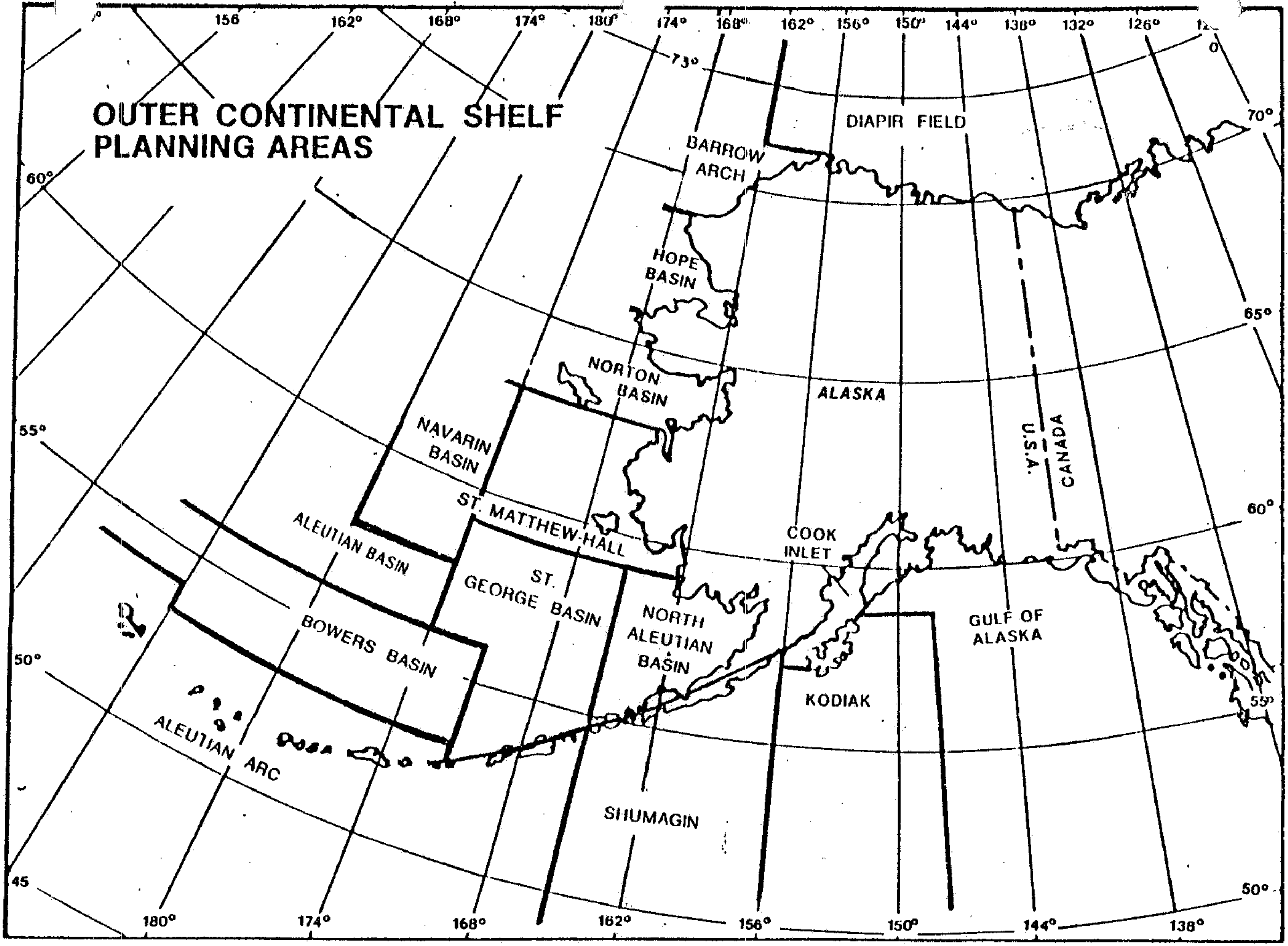
BILLING CODE 4310-10-C

OUTER CONTINENTAL SHELF PLANNING AREAS



U.S. Department of the Interior Map

Figure 4



U.S. Department of the Interior Map

Table 2

1. Responses to 12/31/80 Federal Register Notice

Chevron:

Add - Norton Sea - portion covered in EIS but not included in sale 57

- Beaufort Sea - offshore NPRA and offshore Arctic National Wildlife Range
- Bristol Bay - schedule for August 1984

Pennzoil:

Follow existing schedule

Gulf:

For 1985 & 1986, add:

- Beaufort Sea - east of 1979 leased area
- Northern & Central California - particularly Eel River Basin
- Washington and Oregon

Cities Service:

Follow existing schedule

Amoco:

- Favor more frequent sales in frontier areas
- Hold a sale in the near term in Bristol Bay - combine it with N. Aleutian Shelf, sale 75
- Accelerate, preferably to 1983

  80 - California

  83 - Navarin

  85 - Chukchi

  86 - Hope

- Ranking of other areas: 1. Gulf of Mexico

  2. Mid-Atlantic

  3. North and South Atlantic

Mobil:

- Change emphasis from excessive reliance on Gulf of Mexico to frontier areas, particularly Alaska: "The nation could derive a much greater return on it's [sic] increasingly scarce petroleum technicians and their equipment if emphasis were shifted to the Alaskan frontier where potential exists for discovery of much larger hydrocarbon accumulations."

ARCO:

Provided ranking table, which is included in the table 1 aggregate ranking.

Exxon:

Provided ranking table, which is included in the table 1 aggregate ranking.

- Of frontier areas, St. George and Navarin should be leased and explored first; timing for Chukchi sale (in 6/80 program) seems about right.

- Recommend early evaluation of Central and Northern California, North Aleutian Shelf/Bristol Basin, and Norton.

- Basins in low potential category should receive little or no emphasis as would divert industry from more promising areas.

- Sale recommendations:

  1. St. George early in 1982 and in 1985

  2. Add Beaufort Sea sale in 1984

  3. N. Aleutian Shelf sale in late 1982

  4. Navarin sale in early 1983

5. Postpone Kodiak and Hope beyond the schedule

Shell:

- Provided ranking table, which is included in the table 1 aggregate ranking.
- Sales 60 and 61 Cook Inlet and Kodiak should be cancelled
- Current schedule for other areas is O.K. Proposed Alaska schedule:

Norton	1982, 1983
St. George	1982, 1983, 1984, 1985
Beaufort	1982, 1983, 1984, 1985
N. Aleutian Shelf	1983, 1984, 1985
Chukchi	1984, 1985
Hope	1985

Diamond Shamrock:

Provided ranking table, which is included in the table 1 aggregate ranking.

Champlin:

Provided comments on existing information on each area and ranking table, which is included in the table 1 aggregate ranking.

Union Oil:

- Changes needed only for Alaska sales, to integrate anticipated NPRA sales, State of Alaska sales, and California OCS sales into an overall schedule:

  Bristol Bay - 1984

  Norton - delay to 3rd quarter of 1983

  Chukchi - delay to 4th quarter of 1985

  Hope - delay to 2nd quarter of 1986

Pogo:

Accelerate Alaska sales

2. Responses to April 1981 draft proposed program

ARCO: Immediate attention not warranted on

St. Matthew-Hall

Hope Basin

Bowers Basin

Shumagin

Aleutian Arch

Kodiak

Aleutian Basin

Chevron: Kodiak has greater potential than St. Matthew-Hall

Exxon: Drop St. Matthew-Hall, add 2nd sale in Navarin

Shell: Kodiak, Shumagin, Aleutian Arch, Aleutian Basin and Bowers Basin should be offered last

APPENDIX 6

Comments

Eighty-three letters were received on the July 1981 proposed program. This was the fourth opportunity for public comment since the annual review of the 5-year program was started in December 1980. Comments on the proposed program fall into three general groups--comments on size, timing and location of sales on the schedule; comments on streamlining the leasing process; and general comments on compliance with section 18 of the OCS Lands Act and other topics.

Size, Timing and Location of Leasing

Planning Area - Specific Comments

Alaska--Governor Hammond opposes the pace and magnitude of the proposed program. He recommends postponing the North Aleutian Basin and St. George Basin sales until after completion of the Cooperative Management Plan mandated by section 1203 of the Alaska National Interest Lands Conservation Act and of CZM planning in affected areas. The Whale Center recommends coordinating all phases of lease sales with CZM plans of Alaskan communities. For St. George Basin, Alaska suggests that tract deletion might be a suitable alternative or complement to postponement. Alaska also recommends delaying sales in Navarin, Norton and Hope Basins until 1984-1985, to allow completion of local CZM plans and development of exploration and development techniques, transportation methods, and mitigation measures. These deletion and delay recommendations are analyzed as Alternative IV-1 in the SEIS and as Alternative IV in the SID. Alaska also recommends coordination of Federal OCS leasing with Federal onshore leasing and the State leasing program. The United Fishermen of Alaska also recommend deleting North Aleutian Shelf, St. George Basin, and other lease sales that affect Bristol Bay and Southeastern Bering Sea fisheries. The same group requests delay of Kodiak and Norton Sound sales. One private individual also requests that sale #57 - Norton Basin be changed. The North Slope Borough opposes the increase in pace and scope of sales in the Beaufort and Chukchi Seas. The Borough also questions statements by the Department about availability of environmental information as a controlling factor in determining timing of re-entry sales. Alaska recommends indefinite postponement of sales in Barrow Arch and the offshore pack ice zone of Diapir Field, until there is a comprehensive environmental data base for development of appropriate regulatory mechanisms and more advanced technology for Arctic waters. The Natural Resources Defense Council (NRDC) opposes leasing in Bristol Basin and part of Chukchi Sea. The Alaska Eskimo Whaling Commission opposes acceleration of leasing in the Arctic. Deletion of arctic sales is analyzed as Alternative IV-2 in the SEIS and as Alternative V in the SID.

Mobil requests changes in the dates of three sales to take into account winter and summer seismic seasons. Marathon objects to delays in Alaska sales beyond the timeframe in the proposed program. Shell believes that sale #70--St. George Basin and ARCO that sale #75--North Aleutian Basin should not be delayed beyond the timeframe in the proposed program. Chevron and BP support changes that were made between the draft and the proposed program based on arctic weather windows and planned COST wells. Congressman Gejdenson believes that "South Alaska" is too large for State and local government planning.

California--State and local officials, Congressmen, and environmental groups have questioned the size and timing of sales off California. The State recommends deletion, on the basis of risks outweighing benefits, of the following areas: Santa Cruz, Point Arena, Bodega and Eel River Basins; all tracts north of Pt. San Luis in Santa Maria Basin; all tracts in the Santa Barbara Ecological Preserve and Buffer Zone; Santa Monica Bay; the area offshore San Diego County; all tracts within the Channel Islands and Point Reyes/Farallon Islands National Marine Sanctuaries; tracts within access routes to the Ports of Los Angeles, Long Beach and San Luis; basins offshore San Mateo and Mendocino; Humboldt Basin; and Santa Barbara North Coast. California also recommends deletion of the Santa Barbara Channel because it has already been leased twice and most leasable tracts have been offered. California also recommends deletion of deepwater tracts due to unproven technology. Finally, California advises the Secretary that it is State policy for OCS development to occur only in areas where the resources justify pipeline transportation.

Deletion recommendations from Marin and Santa Cruz Counties, SANDAG and the Whale Center overlap with those from the State. The Whale Center also recommends deletion of all tracts in the Santa Maria Basin within 6 miles of Point Buchon, Morro Rock, Lion and Pecho Rocks and the Nipomo Dunes; the California Sea Otter Range; all areas previously deleted from other sales in the Santa Barbara Channel and the southern California Bight. California, Marin County, and Representatives Panetta, Fazio, Miller, Mineta, Phillip Burton, John Burton, and Lantos believe the California planning areas are too large. California and Humboldt County recommend limiting sales to one sedimentary basin.

ARCO recommends that California sales remain in mid-year (as in the June 1980 program) because the limited supply of west coast seismic boats is in Alaska in the summer months and in California in the winter months, in time for a mid-year California sale. Marathon objects to delays in California sales beyond the timeframe in the proposed schedule.

Gulf of Mexico--Alabama strongly urges that tracts in or adjacent to the area in litigation between the State and the Federal Government be excluded from the 5-year program.

South Atlantic--South Carolina and Florida oppose the timing of sale #78--South Atlantic because in their opinion it will not allow experience gained from exploration of sale #56 tracts to be considered. The Outer Banks Chamber of Commerce opposes any leasing off the Outer Banks.

North Atlantic--Maine, New Hampshire and Massachusetts object to consolidation of the North and Mid-Atlantic planning areas. Maine recommends that sale #90 be designated Mid-Atlantic and sale #96 should be North Atlantic. Maine also recommends that if drilling from the most recent South Atlantic sale proves promising, an additional sale could be scheduled there in the next revision of the program. New York asks that the boundary between the North and South Atlantic planning areas be moved to Cape Hatteras. Suffolk County, New York, believes that consolidation of the North and Mid-Atlantic planning areas can be advantageous to New York as impacts from the two areas can be treated comprehensively, but is concerned that State comments on the broader area may not be given as much weight. New Jersey believes there are too many sales offshore New Jersey in too few years to assess fully the effects on New Jersey. NRDC opposes the schedule change for Georges Bank. Representatives Studds, Mavroules, Schneider and Markey; Senators Kennedy and Tsongas; and the Natural Resources Council of Maine believe sale #52--North Atlantic is scheduled too soon.

General Size, Timing and Location Comments

Many commentators object to area-wide offerings. The most common basis for this objection is that area-wide offerings do not meet the "as precisely as possible" requirement of section 18 (Maine, New Hampshire, Massachusetts, California, Alaska, North Slope Borough). New Hampshire believes area-wide offerings would make balancing impossible. The North Slope Borough believes area-wide offerings improperly delegate section 18(a)(3) responsibility to private industry. Another common basis for objection is that area-wide offerings would inhibit State and local participation in the OCS program (California, Marin County, Representative Edwards, Senator Dodd, one private citizen) and would place impossible burdens on industry and local, State and Federal Government evaluation and planning (North Slope Borough, Humboldt County, Senator Dodd, Nantucket Land Council, Natural Resources Council of Maine). Marathon comments that small and medium size companies will not have the resources to evaluate so much acreage and to bid effectively. Maine, New Hampshire, Marathon and a private citizen believe area-wide offerings will diffuse exploration efforts into areas with less merit and thus will delay discovery of oil and gas.

Several commentators object to area-wide offerings on environmental grounds, either because they believe that assessment of adverse effects will be impossible (Representatives Studds, Mavroules, Schneider, and Markey; Senators Kennedy and Tsongas) or because they believe areas with sensitive environmental resources but no hydrocarbon potential should not be offered at all (Maine, New Hampshire, Massachusetts). New Hampshire and Maine believe that including areas with no hydrocarbon potential in area-wide offerings will lead to needless controversy, and that sedimentary basins with the greatest potential for oil and gas deposits should be the focus of consideration. Humboldt County believes area-wide offerings will decrease environmental protection and exacerbate coastal land use conflicts. The California Department of Conservation is concerned about the difficulty in providing detailed information about available gas reserves, geologic hazards, environmental effects, and secondary impacts for larger bidding areas. They also believe that the geologic diversity of large areas presents varied problems. Friends of the Earth believes that area-wide offerings would present difficulties in lease management, and several environmental groups believe they could endanger safe operations by industry and the ability of the Department of the Interior to assure safety of operations (NRDC, Sierra Club, Whale Center). Senator Dodd, Representative Gejdenson and the Washington State Department of Ecology recommended smaller offerings.

Florida believes that area-wide offerings will not speed exploration in frontier areas; Washington and the North Slope Borough believe they will not speed exploration anywhere. Senators Weicker, Mitchell, Cohen, Cranston and Hollings; Representative Gejdenson; Washington and Florida are also concerned that the government may not receive adequate monetary return with area-wide offerings. North Carolina believes area-wide offerings are not appropriate for the South Atlantic, where a limited, "high interest" tract selection offering should be used. North Slope Borough believes area-wide offerings are inappropriate for the Arctic, where sales should be based on environmental factors.

ARCO expresses support for increasing acreage offered. Shell and Exxon suport either area-wide or areas of hydrocarbon potential offerings. Marathon recommends offering six compact (3 million acres) areas each year.

California requests that RS-2 be deleted, and NOAA and NRDC oppose reoffering sales generally.

Finally, several commentators express the view that 2 years between repeat sales in an area is not enough time for evaluation of existing operations and environmental information, and for public and private planning (Maine, New Hampshire, Massachusetts, California, Humboldt County, Representative Gejdenson). Senators Weicker, Cohen, Mitchell, Cranston and Hollings believe 2 years between sales will limit the Department's ability to develop environmental safeguards for each sale area. California believes that the timing of lease sales does not comply with the Court of Appeals decision. The North Slope Borough believes that environmental and coastal zone considerations did not receive adequate attention in timing decisions.

Streamlining

General - New Jersey and North Carolina express qualified support for the streamlining procedures. Other commentators are concerned that streamlining would reduce environmental safeguards (North Slope Borough, Los Angeles City Attorney), increase uncertainty (NOAA), and prevent the Secretary from meeting his statutory duty to protect marine, coastal and human environments (Senators Weicker, Cohen, Mitchell, Cranston and Hollings, NRDC). NOAA believes it will be difficult to identify biologically sensitive or geophysically hazardous tracts under the proposal and suggested an alternative streamlining proposal. Suffolk County sees little reason for streamlining since only a small portion of potential tracts has been leased. Representative Gejdenson agrees, noting that 39% of the tracts leased between 1954 and 1979 were never drilled.

Environmental Impact Statements - Many commentators express concern about the amount of time and information that will be available for EIS preparation. The general concern is that area-wide EIS's and NEPA documents prepared for repeat sales in an area would not provide enough information for decisionmakers or to meet legal requirements (Maine, New Hampshire, New York, New Jersey, South Carolina, Washington, North Slope Borough, Marin County, San Francisco, Friends of the Earth, NRDC, Nantucket Land Council). Representatives Panetta, Fazio, Miller, Mineta, Lantos, John Burton and Phillip Burton, and New Hampshire recommend retaining tract-specific environmental assessments. New Jersey finds the lack of tract-specific analysis unacceptable. Marin County, San Mateo County, Santa Cruz County, and Suffolk County believe area-wide EIS's will discount the significance of localized environmental impacts. Connecticut recommends focusing EIS's on areas most likely to be affected, using USGS pre-sale resource estimates. The Whale Center believes that assessing entire planning areas is an inefficient use of limited resources.

Maine, New Hampshire and Masschusetts support various aspects of the streamlined EIS preparation process, but recommend early review of information developed during the pre-Call period by the States and the Regional Technical Working Groups. Maine advises that discussion of socio-economic effects must be included in lower 48 as well as Alaska sale EIS's. The American Planning Association recommends extending the DEIS and FEIS review periods.

Environmental Studies Program - Much concern has been expressed about the ability of the environmental studies program to provide information sufficient to support the accelerated program (Massachusetts, North Carolina, South Carolina, Florida, California, Marin County, Santa Cruz County, San Francisco, Senators Weicker, Cohen, Mitchell, Cranston and Hollings, Sierra Club, Friends of the Earth, NRDC, Whale Center). Several commentators focus on problems they foresee in conducting detailed studies post- rather than pre-sale (Massachusetts, New Jersey, San Mateo County, Suffolk County, Natural Resources Council of Maine). Massachusetts is particularly concerned that 2 years between sales is not enough time for environmental studies information to be developed for planning and decisions on future sales. Florida recommends that a 5-year studies plan accompany the 5-year leasing program. California requests preservation of the present studies program.

Geohazards - Several commentators request that pre-sale, site-specific geohazards studies be continued (New Jersey, California, Marin County, Santa Cruz County, Humboldt County, San Francisco). Suffolk County is concerned that conducting only post-sale geohazards studies may not be in the public interest.

Resource Estimates - New Jersey supports elimination of two USGS estimates. Many other commentators oppose elimination of pre-sale, site-specific resource estimates (California, Santa Cruz County, Suffolk County, Senator Dodd), either on fair market value grounds (Washington Department of Ecology, Representative George Miller) or on "balancing" grounds (Marin County, Representative Gejdenson).

Fair Market Value - Comments on this topic fall into three general categories. First, several commentators believe that the program itself--the increased size of offerings and streamlined procedures--will result in less competition and lower revenues (New Jersey, California State Lands Commission, Los Angeles, Los Angeles City Attorney, Representative Gejdenson, Senators Dodd, Weicker, Cohen, Mitchell, Cranston and Hollings, NRDC, Whale Center). Second, differing views are expressed on the reliability of the competitive market to assure receipt of fair market value. New Hampshire believes overall that current bids for leases represent fair market value and pre-evaluation of all leases is not required. Marathon and Shell believe that Department of the Interior bid evaluation is unnecessary to assure fair market value and that all high bids above a stated minimum should be accepted, regardless of the number of bids on a tract. The California State Lands Commission believes the OCS lease market is not competitive enough to assure receipt of fair market value. The California Department of Conservation believes evaluation of fair market value should be based differently. New Hampshire supports evaluation of a random 5 percent of tracts receiving more than 3 bids, but believes only 50 percent rather than all of the tracts receiving less than 3 bids should be evaluated. New York believes a statistically significant percentage of bids should be evaluated. Representative Gejdenson believes that post-sale fair market value evaluations won't work because of insufficient time for the type of analysis required. On a related topic, New York questioned raising the minimum bid on the grounds that this might restrict exploration in high risk areas.

Planning Milestones -

1. Call for Information: Massachusetts and the American Planning Association suggest requiring oil companies to provide an indication of the extent of their interest in areas. Santa Cruz County suggests that the Call should evaluate local resource conflicts identified by local governments. The California Air Resources Board believes it will be difficult to participate effectively in the Call. Humboldt County recommends 60 rather than 30 days for response to the Call.

2. Tract Selection: Opposition to elimination of tract selection is expressed by California, Washington, Alaska, Marin County, Santa Cruz County, San Mateo County, Los Angeles City Attorney, Representative Edwards, NOAA, NRDC, the American Planning Association, and two private citizens. Washington, Marin County, Santa Cruz County, San Mateo County, and Los Angeles City Attorney believe that tract selection is an important opportunity for State and local participation which will be lost under streamlining. Sierra Club, Friends of the Earth and NOAA believe that elimination of tract selection will preclude identification of hazardous or sensitive tracts. On this point, New York recommends that the program include sale planning procedures to insure that tracts are identified and deleted where serious environmental conflicts may occur. The Washington Department of Ecology is concerned that it may be illegal and is certainly unconscionable to delete tracts after industry has invested in them. Representatives Panetta, Fazio, Miller, Mineta, Phillip and John Burton, and Lantos recommend publishing the tract list earlier.

3. Proposed Notice of Sale: New Jersey supports simultaneous issuance of the proposed Notice of Sale and final EIS; Humboldt County opposes it. New Hampshire believes the proposed notice should be issued at least 30 days after the final EIS, to give Interior and other affected parties time to consider the alternatives analyzed in the EIS before final tract selection, establishment of bidding systems and proposed stipulations. NRDC believes the timing of the proposed Notice of Sale allows insufficient time for information assessment. Representatives Panetta, Fazio, Miller, Mineta, Phillip Burton, John Burton, and Lantos oppose what they see as the proposed elimination of the proposed Notice of Sale stage.

Section 18 and General Comments

Section 18--Many commentators express the general view that the proposed program does not meet the requirements of section 18 (Massachusetts; Washington Department of Ecology; California Department of Conservation, Air Resources Board and Coastal Commission; North Slope Borough; San Mateo County; Los Angeles; Senators Dodd, Weicker, Cohen, Mitchell, Cranston, Hollings, Kennedy and Tsongas; Representatives Panetta, Fazio, Miller, Mineta, Phillip Burton, Lantos, John Burton, Studds, Mavroules, Schneider, Markey, and Gejedenson; Sierra Club; NRDC; Whale Center; Nantucket Land Council). Maine believes that all areas cannot be offered because oil and gas benefits cannot always outweigh other values. Maine also recommends that the program clearly explain how balancing will be done at the lease sale stage and how the program will maximize oil and gas benefits and minimize the possibility of damage to other values. Massachusetts believes that in regions with potential for oil and gas, it may be necessary to delete some areas, based on section 18(a)(2) requirements. North Carolina recommends that the effects of transportation be considered in the section 18 risk/benefit analysis.

On a related topic, a number of commentators offer interpretations of the D.C. Circuit Court opinion in California v. Watt, No. 80-1894. For example, California believes the court opinion requires a demonstration of how area-by-area cost-benefit analyses will be used to determine the location and timing of lease sales. Alaska and the North Slope Borough provide interpretations of how the court opinion should be used to develop a new 5-year program. Alaska, Senators Kennedy and Tsongas, and Representatives Studds, Mavroules, Schneider and Markey believe the proposed program contains the same infirmities that the court found in the June 1980 program. Alaska believes the court opinion requires issuance of a new draft program; North Slope Borough and NRDC believe it requires issuance of a new proposed program. Massachusetts and Alaska provide information on marine productivity for use in complying with the court opinion.

Industry Capability--New York, New Jersey, the Washington Department of Ecology, Representatives Miller and Gejdenson, NRDC, and the Natural Resources Council of Maine believe industry may not be capable of utilizing increased lease offerings. Many of these comments focus on the belief that there are shortages of industry personnel, equipment and capital. API and Shell, on the other hand, express confidence that industry has the capability to carry out the proposed schedule. API cites technology developed for North Sea, deep water and ice conditions; the number of existing and planned rigs; domestic shipyard expansion to produce rigs and foreign construction of of rigs for U.S. waters; increase in tubular goods production; increase in number of drilling companies; training of additional specialists; in-hand geophysical surveys; and ongoing geophysical work. Shell asserts that industry has already developed technology for production in frontier regions up to 100 feet water depth in ice-covered areas and 3,000 feet in other areas which is adequate for almost all the areas to be leased in the next few years.

General Environmental Concerns--Several commentators expressed concern about environmentally sensitive areas. Massachusetts recommends that environmentally sensitive areas that cannot be protected with the best available technology should not be offered, unless the Secretary can show that he has weighed the risks of damage and the potential for oil and gas discovery and that all necessary mitigating measures will be required. The California Air Resources Board recommends excluding environmentally sensitive areas from the OCS planning process. The American Planning Association recommends limiting early sales to the least sensitive ecological areas. Alabama is encouraging industry to coordinate their activities in Federal and State waters to mitigate any impacts that may result in the Alabama coastal area.

Shell believes the program can be conducted in an environmentally safe manner; environmental safeguards are built into the system and the history of the OCS program demonstrates its safety.

Several commentators focused on specific resources of concern. California and Marin County believe the program provides inadequate protection for onshore air quality. The United Fishermen of Alaska believe the program reduces protection of fishing grounds. They request re-evaluating the sections of the EIS related to fishery impacts and review of the Fishermen's Contingency Fund. Other resources or effects which commentators believe are inadequately considered are:

- -- oil spills (California Department of Conservation, Marin County, Santa Cruz County, North Slope Borough--particularly concerned about effects on bowhead whale)
- -- coastal and marine environments (Washington Department of Ecology)
- -- onshore facilities (California Department of Conservation)
- -- marine sanctuaries (California Coastal Commission)

-- anadramous fish (Washington Department of Ecology)

-- cumulative effects (North Slope Borough, Marin County--sales 73 and 91, California Coastal Commission)

-- secondary effects (California Coastal Commission)

-- inflation (Washington Department of Ecology)

The Washington Department of Ecology and NRDC believe the program will have serious environmental consequences. Louisiana is concerned that present knowledge of the central Gulf may be inadequate to insure an adequate evaluation of the environment if there is a significant increase in the level of OCS development.

Several comments focus on EIS or NEPA issues. Los Angeles believes the plan would violate NEPA. They and the North Slope Borough find the DSEIS inadequate. California and the North Slope Borough call for a new 5-year program DSEIS. Maine and Massachusetts recommend including socio-economic impact analysis in EIS's outside of Alaska. Finally, the California Department of Conservation believes environmental considerations are not incorporated into decisionmaking early enough.

Coastal Zone Concerns--The North Slope Borough comments that a June 15, 1981, memorandum on the proposed program and the DSEIS are inconsistent in their conclusions about coastal zone effects. Oregon believes OCS leasing activities directly affect the coastal zone. The Washington Department of Ecology believes that rewriting section 307 of the Coastal Zone Management Act is an attempt to prevent States from participating. They also note that the program calls for additional support bases and fabrication sites in Oregon and Washington. They believe the proposed program should include a statement that these will be located where there would be the least coastal zone impact, because if they cannot obtain coastal zone approval, the program will be hindered.

Federal Funding--Maine, New Hampshire, Massachusetts, Connecticut, New York, Senators Weicker, Cohen, Mitchell, Cranston and Hollings, and the Natural Resources Council of Maine are concerned about the level of funding and staffing available for the Department to implement the proposal. Of particular concern is funding for the Environmental Studies Program. although some of these commentators focused on other aspects of the OCS program as well.

State and Local Government Participation--Maine, New Hampshire, Connecticut, New York and Washington believe that the State's ability to participate in the OCS program will be severely affected by cutback or elimination of Federal assistance to States (e.g., CEIP, CZM). Humboldt County believes that Federal assistance (CZM, CEIP, LWCF) must be provided so that net local benefit from any projects will be assured. A more general concern expressed by commentators is the program may be burdensome or costly for State and local governments (NOAA, Whale Center, Los Angeles City Attorney). Representatives Panetta, Fazio, Miller, Mineta, Phillip Burton, Lantos and John Burton believe the proposal will jeopardize the environmental economies of coastal areas. Representative Edwards believes the program will create coastal management problems. Representatives Lagomarsino and Clausen believe the program should be more sensitive to locally expressed concerns. Representatives Panetta, Fazio, Miller, Phillip Burton, Lantos, and John Burton, Friends of the Earth and the Natural Resources Council of Maine believe the program will inhibit State and local participation.

Planning Area Name Changes--Friends of the Earth and a private citizen oppose renaming planning areas.

General--Maine, New Hampshire, Massachusetts, Virginia and Florida express support for the objectives of the proposed program, although all express some concerns about environmental protection. Alabama believes the program should help accelerate development of domestic oil and gas reserves and provide for collection of data necessary to protect the environment. Louisiana totally supports the Department's effort to emphasize leasing of high potential areas. Texas believes the program is consistent with national goals. The Departments of Justice and Energy have no objection to the program. Getty, Chevron, BP Alaska Exploration, Shell, Champlin, API, and Exxon support the proposed program. Marathon generally concurs with the timing of sales and with efforts to eliminate delays. API notes that differences between competing companies about optimal size and scheduling of sales reflect differing financial and technical resources and exploration strategies. The important issue is directional change, and proposed program is moving in the right direction. API, Chevron, Shell and Exxon include analysis of the effectiveness of proposed changes, and Chevron analyzes the defects of the present leasing process. Champlin believes the program should be strictly adhered to once adopted because reliability and predictability are imperative for effective planning.

Washington supports the current program, which it believes offers predictability. Washington also notes that the proposed program does not include adequate information to evaluate its merits, how natural systems will be protected or how program will contribute to increased production. They believe the proposed program ignores the crude surplus, suspension of drilling activity and relinquishment of leases where results have been disappointing, the existence of 3.7 million acres of unexplored, leased lands, and litigation over sale 53--Central and Northern California involving the interpretation of direct effect on the coastal zone. They also question the wisdom of expediting leasing where clean-up technology, critical environmental information and offshore experience are lacking. North Slope Borough believes the June 1980 and July 1981 programs contain the same flaws, which must be corrected. Senators Weicker, Cohen, Mitchell, Cranston and Hollings and Representative Edwards believe the program would lead to further litigation. Whale Center believes that valuable and fundamental economic activities are ignored in the haste to cater to the hydrocarbon industry and that the 1980 program should be reconstructed to address recent court findings and congressional attempts to insure consistency with State goals. The Natural Resources Council of Maine opposes the increase in the number of sales and acreage. NRDC believes the program will not inventory OCS resources. A private citizen believes there is no proof of an acute energy shortage and that less environmentally damaging alternatives exist. Humboldt County recommends adoption of something similar to the June 1979 Department of Energy OCS leasing schedule, which they believe concentrates offerings in areas of high potential, maximizes economic value, makes efficient use of manpower and equipment, assures competition, and gives low priority to economically marginal areas.

Industry provides a number of specific comments on topics of concern. Marathon recommends lease blocks in deepwater of hostile areas be no bigger than four contiguous OCS tracts. They believe this would assure diversity of ownership and geologic interpretations as well as adequate competition if their recommendation for 3-million acre sale limit is adopted. Marathon, BP Alaska Exploration, and Champlin recommend 10-year lease terms with no additional work commitment clauses for lease sales in deepwater or hostile environments. Champlin believes this policy should be announced concurrently with approval of 5-year program, to encourage companies that otherwise would not bid to go out and collect and evaluate data they will need to bid. BP Alaska Exploration believes the cash bonus/fixed royalty bidding system is most compatible with areawide offerings.

Representative Miller recommends delaying program changes until an improved royalty collection system is in place and developing a more thorough process for fulfilling due diligence requirement of OCSLA. Maine recommends considering computer mapping of planning area information. New Hampshire and Maine believe that information should be provided to States as early as possible. Alaska recommends considering North Aleutian Basin and St. George lease sales in section 1203 plan, and utilizing the findings of studies required under section 1203 of the Alaska National Interest Lands Conservation Act, to the maximum extent possible, in decisions on lease sales. Louisiana is concerned that, because of a history of objections and delays to leasing outside the Gulf of Mexico, industry may concentrate on the proven area of central Gulf. They believe this would create severe economic and environmental impacts for Louisiana and lead to a major rate of depletion. Louisiana recommends that the program be amended to safeguard against this and ensure other OCS areas receive their fair share of exploration and development.

List of Commentators on Proposed 5-Year Program

State

Governor Edward King, Massachusetts
Governor Hugh Carey, New York
Governor Jay Hammond, Alaska
Governor Harry Hughes, Maryland
Governor William Clements, Texas
Governor Hugh Gallen, New Hampshire
Governor Edmund Brown, California
Governor Bob Graham, Florida
Governor Richard Riley, South Carolina
Governor James Hunt, North Carolina
Governor Victor Atiyeh, Oregon
Governor Brendan Byrne, New Jersey
Governor John Spellman, Washington
Governor William Winter, Mississippi
Governor Joseph Brennan, Maine
Governor Fob James, Alabama
Mark Chittum, New Hampshire
David Carlson, Virginia
Frank Ashby, Louisiana
Charles Colgan, Maine
Joseph Belanger, Connecticut
California Air Resources Board
California Coastal Commission
California Department of Conservation
California Department of Fish and Game
California State Lands Commission
Robert Flacke, New York
James Souby, Alaska
Maurice Rowe, Virginia
Donald Moos, Washington
Deni Greene, California

Local

Robert Blodgett, Bering Strait Coastal Resource Service Area Planning Board
Bruce Terris & James Hecker, transmitting comments of North Slope Borough
Joan Martin, San Diego Association of Governments (SANDAG)
Jan Chatten-Brown, Office of City Attorney, Los Angeles
Danny Walsh, County of Humboldt
Warner Chabot, Marin County
Paul Koenig, San Mateo County
Gary Patton, Santa Cruz County
Dan Forbus, Association of Monterey Bay Area Governments
Dean Macris, San Francisco

Environmental

Elizabeth Kaplan, Friends of the Earth
Shirley Taylor, Sierra Club National Coastal Committee
Sarah Chasis & Frances Beinecke, Natural Resources Defense Council (consolidated comments of NRDC, Center for Environmental Education, National Audubon Society, Conservation Law Foundation of New England, Environmental Policy Center, Defenders of Wildlife, and Sierra Club)
Myrt Jones, Mobile Bay Audubon Society
Jerry Bley, Natural Resources Council of Maine
Pamela Ferris-Olson, Whale Center

Federal

Jan Mares, Department of Energy
William Matuszeski, Department of Commerce
William Baxter, Department of Justice

Industry

S. F. Peterson, Getty Oil
R. R. Burke, Marathon Oil
Charles DiBona, American Petroleum Institute
D. H. Hutchinson, Mobil Oil
R. H. Nanz, Shell Oil
L. C. Soileau, Chevron
James Maytum, Champlin
P. Hardwick, BP Alaska Exploration
E. F. Livaudais, ARCO
J. D. Langston, Exxon

Congressional

Sen. Edward Kennedy
Sen. Paul Tsongas
Sen. Christopher Dodd
Sen. William Cohen
Sen. George Mitchell
Sen. Lowell Weicker
Sen. Alan Cranston
Sen. Ernest Hollings
Rep. Gerry Studds
Rep. Nicholas Mavroules
Rep. Claudine Schneider
Rep. Edward Markey
Rep. George Miller
Rep. Don Edwards
Rep. Robert Lagomarsino
Rep. Don Clausen
Rep. Vic Fazio
Rep. Leon Panetta
Rep. Norman Mineta
Rep. Phillip Burton
Rep. John Burton
Rep. Tom Lantos
Rep. Sam Gejdenson

Other

Mary Preston
Patrick Dobey, Petroleum Geologist
Florence Ungerman
Theresa Pederson, Research Consultant
S. Lynn Sutcliffe, Counsel to the Alaskan Eskimo Whaling Commission
James Watson, American Planning Association, New England Chapter
Rodger Painter, United Fishermen of Alaska
Harold O'Briant, The Outer Banks Chamber of Commerce
John Roe, Nantucket Land Council, Inc.

APPENDIX 7

Estimated Appropriations and Staff Requirements for Tentative Proposed Final 5-Year Leasing Program

Format

The following tables provide estimates of appropriations and full-time equivalent staff (FTE) necessary to support each of the alternative leasing programs discussed in the SID.

The alternatives are:

Alternative I-1:	July 1981 Proposed Program with Area-wide Offerings (July 1981)
Alternative I-2:	July 1981 Proposed Program with December 1981 Refinement of Area-wide Offerings
Alternative II:	April 1981 Draft Proposed Program
Alternative III-1:	June 1980 Program with Traditional Size Sales
Alternative III-2:	June 1980 Program with Larger Offerings
Alternative IV-1:	July 1981 Proposed Program with Delay or Deletion of Certain Alaska Sales and Area-wide Offerings (July 1981)
Alternative IV-2:	July 1981 Proposed Program with Delay or Deletion of Certain Alaska Sales and December 1981 Refinement of Area-wide Offerings
Alternative V:	July 1981 Proposed Program with Deletion of Arctic Sales

With the exception of Alternative III, these estimates are for the period from FY 1982 through FY 1987. Alternative III, the June 1980 Program, estimates cover the period from FY 1982 through FY 1985. These estimates cover only that work required for sales on the schedule in question. That is, they do not cover planning and studies activities for sales which might occur in years following the end of the schedule. The estimates for pre-sale appropriations and staff requirements therefore decline toward the end of the 5 years. Of course, the addition of sales in subsequent years would modify that pattern. It should be noted that these are initial estimates; while they represent a careful effort to project the requisite resources, they have not been evaluated through either internal or Office of Management and Budget processes and are subject to refinement, especially during the annual budget preparation process.

The estimates include a new organization--the Minerals Management Service (MMS) which is responsible for a number of functions previously carried out by the USGS. In some areas, the division of budgetary resources between MMS and USGS has not yet been decided. These are noted on the tables.

The data are displayed in accordance with section 18(b) of the OCS Lands Act, as amended, which requires estimates for four specific activities. A fifth category, General Administrative Activities, was added to cover those activities not specifically listed in section 18(b) but necessary in order to fully reflect the cost of managing the program. These five categories of activities are described below.

1. Obtain resource information and any other information required to prepare the leasing program (18(b)(1)). This includes the work performed by the USGS and Minerals Management Service (MMS) in preparing area-wide oil and gas resource assessments, specific evaluations for lease sale decisions and assessments for bid acceptance decisions. MMS estimates for this activity for Alternatives I and IV are higher for area-wide offerings (July 1981) than for the December 1981 refinement of area-wide offerings. Also included is the biological resource information provided by FWS.

2. Analyze and interpret exploratory data and any other information that may be acquired under the OCS Lands Act, as amended (18(b)(2)). This activity covers the MMS operation of the OCS oil and gas information program mandated by the OCS Lands Act, as amended.

3. Conduct environmental studies and prepare environmental statements (18(b)(3)). This activity covers costs, including contract costs, for the BLM environmental studies program (e.g., socio-economic, endangered species, resource conflicts) and for preparation of NEPA documents. These estimates reflect the full costs of pre-sale, post-sale and monitoring studies currently planned for the sales in the 5-year program as well as sales recently held for which monitoring and/or postsale studies are ongoing or planned. The increase in FY 1984 for this activity will support post-sale monitoring experiments to measure the effects of OCS production on at least two significantly different ecosystems. One of the experiments will be done in a frontier area where some production has begun and the other in an area of historic OCS development and production. The purpose of this program is to determine whether OCS activity is causing any significant effects on the marine environment. Data from this program and from fates and effects studies should provide a sound technical basis for resource management decisions and should reduce the need for many of the large-scale reconnaissance studies currently supported by the Environmental Studies Program.

USGS and MMS funds and staff, in combination with industry data, are used for 1) regional and area assessments of geologic hazards used in summary reports, 2) oil spill trajectory analysis used in environmental statements, and 3) post-sale evaluation of geologic hazards which may occur on leased tracts.

4. Supervise lease operations (18(b)(4)). This is a function of the MMS. It involves review of exploration, development, production and pipeline plans and operations, and inspections of rigs and platforms to insure safety of operations and compliance with regulations.

Preliminary to exploration drilling, the MMS requires the lessee to submit information on the geologic structure, the drilling vessel, the well locations, environmental conditions, and onshore effects. Except for the more mature Gulf of Mexico area, the MMS requires similar detailed information for development, production, and pipeline plans for the life of the field. Petroleum technicians conduct inspections of both the drilling and production operations with a frequency designed for the activity to assure operational safety and pollution prevention. Petroleum engineers, geologists, and geophysicists review the plans and permits and administer the total regulatory program.

Personnel requirements over the next few years are not expected to vary greatly. The four field OCS regions are staffed to meet the workload demands of today. When centers of activity change, personnel can be shifted accordingly.

Penalties and more competent personnel through training will serve to improve the enforcement program in such a way that additional activity can be administered without increasing staffing. Also, more effective personnel and programming will lead to greater efficiency in inspections; by example, troublesome areas identified by computer can be made aright through a concentration of inspections. While doing this, the areas with a good safety record can be bypassed.

5. General administrative activities. For the BLM, examples of general administrative activities include: preparing, issuing, and analyzing responses to the call for information; preparing decision material for area identification; holding public hearings on environmental statements; preparing sale decision documents; conducting the post-sale analysis of bids to assure receipt of fair market value; supporting the Intergovernmental Planning Program for Leasing, Transportation and Facilities Siting; analyzing and approving rights-of-way applications; and other lease administration activities.

Examples of GS activities include analytical support and participation in most of the steps and activities mentioned in the preceding paragraph, and special support activities such as estuarine and coastal geologic investigations related to onshore impacts of OCS development. In addition, the MMS R&D program provides assurances to the public and supports regulatory personnel regarding best and safest technologies as industry commences operations in frontier areas including the Arctic and North Atlantic. The increase in this activity shown in 1984 and continuing to the end of the program is to provide an appropriate level of support as work in frontier areas increases.

The Fish and Wildlife Service, the National Park Service, the Office of the Solicitor and the Office of OCS Program Coordination all participate in the management of the OCS program and all their costs other than the gathering and analyzing resource information by FWS are included in this activity.

Occasionally, other organizational units of the Department of the Interior, such as the Bureau of Indian Affairs, participate in the OCS program. However, since they do not have a continuing role and do not have specific staff and financial resources dedicated to the management of the OCS program, estimates for them are not included in this analysis.

Assumptions

The costs of the OCS program are a function of many variables, the most important of which are the number, size, and geographic distribution of sales in any year and over the five-year schedule, and the type and extent of workload generated by past and current sales in a specific area. These cost estimates have been prepared using past experience in the program, e.g., knowledge of data needed to support the program, the costs and timing of data acquisition and average workload generated by a sale, the resources needed to supervise lease operations, as general guidelines. The bureaus can estimate from past experience what is likely to be required to support a sale in a particular sale area. For example, in Alaska, common depth point seismic data, acquired under contract, can cost up to twice as much as common depth point seismic data in the Atlantic; weather conditions might seriously affect the environmental studies program in Alaska whereas off the contiguous 48 States weather conditions would not be as serious a constraint on data gathering. Costs of supervising are particularly subject to uncertainty since they depend on the level of exploration, development and production activities which will result during the 5-year period, both from sales on the proposed schedule and from earlier sales.

Estimated Appropriations and Staff Requirements for Alternative I with Area-wide Offerings
(July 1981) 5-Year Leasing Program

Activity	FY 1982 A/		FY 1983		FY 1984		FY 1985		FY 1986		FY 1987	
	$ mil.	FTE	$ mil.	FTE	$ mil.	FTE	$ mil.	FTE	$ mil.	FTE	$ mil.	FTE
Resource Info:												
USGS	10.8 B/	265 B/	11.8 B/	256 B/	19.4	256	19.4	256	19.4	256	19.4	256
MMS	29.4 B/	401 B/	32.9 B/	398 B/	43.6	550	44.6	570	45.6	580	46.8	590
FWS	.2	5	.2	5	.2	5	.2	5	.2	5	.2	5
Total	40.4	671	44.9	659	63.2	811	64.2	831	65.2	841	66.4	851
Exploration Data:												
MMS	2.3	5	2.3	5	2.5	6	2.7	6	2.7	6	2.9	6
Environ. Statements and Studies:												
BLM	35.0	141	38.0	164	41.6	168	29.4	153	22.1	143	16.5	103
USGS	8.6	137	9.1	134	9.3	138	9.3	138	9.3	138	9.3	138
MMS/USGS C/	--	--	--	--	4.3	8	4.0	8	4.5	8	2.5	4
Total	43.6	278	47.1	298	55.2	314	42.7	299	35.9	289	28.3	245
Supervise Lease Ops:												
MMS	30.6	472	29.8	443	32.9	453	34.8	480	36.8	505	36.8	510
Gen. Admin. Activities:												
BLM	4.7	147	5.9	179	6.2	189	5.0	188	4.4	178	3.1	168
USGS	1.4	40	1.4	39	1.4	39	1.4	39	1.4	39	1.4	39
MMS	1.6	3	1.6	3	5.0	6	4.7	6	4.5	5	4.2	5
FWS	.1	1	.1	1	.1	1	.1	1	.1	1	.1	1
POCS	.5	10	.5	10	.5	10	.5	10	.5	10	.5	10
SOL	.3	8	.3	9	.3	9	.4	9	.4	9	.4	9
NPS	.1	2	.1	2	.1	2	.1	2	.1	2	.1	2
Total	8.7	211	9.9	243	13.6	256	12.2	255	11.4	244	9.8	234
Summary:												
BLM	39.7	288	43.9	343	47.8	357	34.4	341	26.5	321	19.6	271
USGS	20.8	442	22.3	429	30.1	433	30.1	433	30.1	433	30.1	433
MMS	63.9	876	66.6	849	84.0	1015	86.8	1062	89.1	1096	90.7	1111
MMS/USGS C/	--	--	--	--	4.3	8	4.0	8	4.5	8	2.5	4
FWS	.3	6	.3	6	.3	6	.3	6	.3	6	.3	6
POCS	.5	10	.5	10	.5	10	.5	10	.5	10	.5	10
SOL	.3	8	.3	9	.3	9	.4	9	.4	9	.4	9
NPS	.1	2	.1	2	.1	2	.1	2	.1	2	.1	2
Total	125.6	1632	134.0	1648	167.4	1840	156.6	1871	151.5	1885	144.2	1846

Estimated Appropriations and Staff Requirements for Alternative I with December 1981 Refinement of Area-wide Offerings 5-Year Leasing Program

Activity	FY 1982 A/ $ mil.	FY 1982 A/ FTE	FY 1983 $ mil.	FY 1983 FTE	FY 1984 $ mil.	FY 1984 FTE	FY 1985 $ mil.	FY 1985 FTE	FY 1986 $ mil.	FY 1986 FTE	FY 1987 $ mil.	FY 1987 FTE
Resource Info:												
USGS	10.8 B/	265 B/	11.8 B/	256 B/	19.4	256	19.4	256	19.4	256	19.4	256
MMS	29.4 B/	401 B/	32.9 B/	398 B/	37.3	550	38.3	570	38.3	580	40.5	590
FWS	.2	5	.2	5	.2	5	.2	5	.2	5	.2	5
Total	40.4	671	44.9	659	56.9	811	57.9	831	57.9	841	60.1	851
Exploration Data:												
MMS	2.3	5	2.3	5	2.5	6	2.7	6	2.7	6	2.9	6
Environ. Statements and Studies:												
BLM	35.0	141	38.0	164	41.6	168	29.4	153	22.1	143	16.5	103
USGS	8.6	137	9.1	134	9.3	138	9.3	138	9.3	138	9.3	138
MMS/USGS C/	--	--	--	--	4.3	8	4.0	8	4.5	8	2.5	4
Total	43.6	278	47.1	298	55.2	314	42.7	299	35.9	289	28.3	245
Supervise Lease Ops:												
MMS	30.6	472	29.8	443	32.9	453	34.8	480	36.8	505	36.8	510
Gen. Admin. Activities:												
BLM	4.7	147	5.9	179	6.2	189	5.0	188	4.4	178	3.1	168
USGS	1.4	40	1.4	39	1.4	39	1.4	39	1.4	39	1.4	39
MMS	1.6	3	1.6	3	5.0	6	4.7	6	4.5	5	4.2	5
FWS	.1	1	.1	1	.1	1	.1	1	.1	1	.1	1
POCS	.5	10	.5	10	.5	10	.5	10	.5	10	.5	10
SOL	.3	8	.3	9	.3	9	.4	9	.4	9	.4	9
NPS	.1	2	.1	2	.1	2	.1	2	.1	2	.1	2
Total	8.7	211	9.9	243	13.6	256	12.2	255	11.4	244	9.8	234
Summary:												
BLM	39.7	288	43.9	343	47.8	357	34.4	341	26.5	321	19.6	271
USGS	20.8	442	22.3	429	30.1	433	30.1	433	30.1	433	30.1	433
MMS	63.9	876	66.6	849	77.7	1015	80.5	1062	81.8	1096	84.4	1111
MMS/USGS C/	--	--	--	--	4.3	8	4.0	8	4.5	8	2.5	4
FWS	.3	6	.3	6	.3	6	.3	6	.3	6	.3	6
POCS	.5	10	.5	10	.5	10	.5	10	.5	10	.5	10
SOL	.3	8	.3	9	.3	9	.4	9	.4	9	.4	9
NPS	.1	2	.1	2	.1	2	.1	2	.1	2	.1	2
Total	125.6	1632	134.0	1648	161.1	1840	150.3	1871	144.2	1885	137.9	1846

Estimated Appropriations and Staff Requirements for Alternative II 5-Year Leasing Program

Activity	FY 1982 A/ $ mil.	FY 1982 A/ FTE	FY 1983 $ mil.	FY 1983 FTE	FY 1984 $ mil.	FY 1984 FTE	FY 1985 $ mil.	FY 1985 FTE	FY 1986 $ mil.	FY 1986 FTE	FY 1987 $ mil.	FY 1987 FTE
Resource Info:												
USGS	10.8 B/	265 B/	11.8 B/	256 B/	26.0	256	19.4	256	19.4	256	19.4	256
MMS	29.4 B/	401 B/	32.9 B/	398 B/	51.5	550	52.5	570	53.8	580	55.5	590
FWS	.2	5	.2	5	.2	5	.2	5	.2	5	.2	5
Total	40.4	671	44.9	659	77.7	811	72.1	831	73.4	841	75.1	851
Exploration Data:												
MMS	2.3	5	2.3	5	2.5	6	2.7	6	2.7	6	2.9	6
Environ. Statements and Studies:												
BLM	35.0	141	38.0	164	41.6	168	29.4	153	22.1	143	16.5	103
USGS	8.9	140	9.1	138	16.0	138	16.3	138	16.3	138	16.3	138
MMS/USGS C/	--	--	--	--	4.3	8	4.0	8	4.5	8	2.5	4
Total	43.9	281	47.1	302	61.9	314	49.7	299	42.9	289	35.3	245
Supervise Lease Ops:												
MMS	30.6	472	29.8	443	28.9	453	31.2	480	31.7	505	32.3	510
Gen. Admin. Activities:												
BLM	4.7	147	5.9	179	6.2	189	5.0	188	4.4	178	3.1	168
USGS	1.4	40	1.4	39	1.4	39	1.4	39	1.4	39	1.4	39
MMS	1.6	3	1.6	3	5.0	6	4.7	6	4.5	5	4.2	5
FWS	.1	1	.1	1	.1	1	.1	1	.1	1	.1	1
POCS	.5	10	.5	10	.5	10	.5	10	.5	10	.5	10
SOL	.3	8	.3	9	.3	9	.4	9	.4	9	.4	9
NPS	.1	2	.1	2	.1	2	.1	2	.1	2	.1	2
Total	8.7	211	9.9	243	13.6	256	12.2	255	11.4	244	9.8	234
Summary:												
BLM	39.7	288	43.9	343	47.8	357	34.4	341	26.5	321	19.6	271
USGS	21.1	445	22.3	433	43.4	433	37.1	433	37.1	433	37.1	433
MMS	63.9	881	66.6	849	87.9	1015	91.1	1062	92.7	1096	94.9	1671
MMS/USGS C/	--	--	--	--	4.3	8	4.0	8	4.5	8	2.5	4
FWS	.3	6	.3	6	.3	6	.3	6	.3	6	.3	6
POCS	.5	10	.5	10	.5	10	.5	10	.5	10	.5	10
SOL	.3	8	.3	9	.3	9	.4	9	.4	9	.4	9
NPS	.1	2	.1	2	.1	2	.1	2	.1	2	.1	2
Total	125.9	1640	134.0	1652	184.6	1840	167.9	1871	162.1	1885	155.4	1671

Estimated Appropriations and Staff Requirements for Alternative III-1 5-Year Leasing Program

Activity	FY 1982 A/		FY 1983		FY 1984		FY 1985	
	$ mil.	FTE	$ mil.	FTE	$ mil.	FTE	$ mil.	FTE
Resource Info:								
USGS	10.8 B/	265 B/	11.8 B/	256 B/	14.3	256	13.3	256
MMS	29.4 B/	401 B/	32.9 B/	398 B/	29.9	550	30.9	570
FWS	.2	5	.2	5	.2	5	.2	5
Total	40.4	671	44.9	659	44.4	811	44.4	831
Exploration Data:								
MMS	2.3	5	2.3	3	2.4	5	2.4	5
Environ. Statements and Studies:								
BLM	35.0	141	28.0	121	25.2	101	22.0	80
USGS	8.9	140	9.1	138	13.2	138	13.2	138
MMS/USGS C/	--	--	--	--	4.3	8	4.0	8
Total	43.9	281	37.1	259	42.7	247	39.2	226
Supervise Lease Ops:								
MMS	30.6	472	29.8	443	32.9	453	34.8	480
Gen. Admin. Activities:								
BLM	4.7	147	5.8	175	5.0	149	4.5	120
USGS	1.4	40	1.4	39	1.4	39	1.4	39
MMS	1.6	3	1.6	3	5.0	6	4.7	6
FWS	.1	1	.1	1	.1	1	.1	1
POCS	.5	10	.5	10	.5	10	.5	10
SOL	.4	13	.5	14	.5	14	.6	14
NPS	.1	2	.1	2	.1	2	.1	2
Total	8.8	216	10.0	244	12.6	221	11.9	192
Summary:								
BLM	39.7	288	33.8	296	30.2	250	26.5	200
USGS	21.1	445	22.3	433	28.9	433	27.9	433
MMS	63.9	881	66.6	847	70.2	1014	72.8	1061
MMS/USGS C/	--	--	--	--	4.3	8	4.0	8
FWS	.3	6	.3	6	.3	6	.3	6
POCS	.5	10	.5	10	.5	10	.5	10
SOL	.4	13	.5	14	.5	14	.6	14
NPS	.1	2	.1	2	.1	2	.1	2
Total	126.0	1645	124.1	1608	135.0	1737	132.7	1734

Estimated Appropriations and Staff Requirements for Alternative III-2 5-Year Leasing Program

Activity	FY 1982 A/		FY 1983		FY 1984		FY 1985	
	$ mil.	FTE	$ mil.	FTE	$ mil.	FTE	$ mil.	FTE
Resource Info:								
USGS	10.8 B/	265 B/	11.8 B/	256 B/	14.3	256	13.3	256
MMS	29.4 B/	401 B/	32.9 B/	398 B/	32.5	550	33.5	570
FWS	.2	5	.2	5	.2	5	.2	5
Total	40.4	671	44.9	659	47.0	811	47.0	831
Exploration Data:								
MMS	2.3	5	2.3	3	2.4	5	2.4	5
Environ. Statements and Studies:								
BLM	35.0	141	28.0	121	25.2	101	22.0	80
USGS	8.9	140	9.1	138	13.2	138	13.2	138
MMS/USGS C/	--	--	--	--	4.3	8	4.0	8
Total	43.9	281	37.1	259	42.7	247	39.2	226
Supervise Lease Ops:								
MMSS	30.6	472	29.8	443	32.9	453	34.8	480
Gen. Admin. Activities:								
BLM	4.7	147	5.8	175	5.0	149	4.5	120
USGS	1.4	40	1.4	39	1.4	39	1.4	39
MMS	1.6	3	1.6	3	5.0	6	4.7	6
FWS	.1	1	.1	1	.1	1	.1	1
POCS	.5	10	.5	10	.5	10	.5	10
SOL	.4	13	.5	14	.5	14	.6	14
NPS	.1	2	.1	2	.1	2	.1	2
Total	8.8	216	10.0	244	12.6	221	11.9	192
Summary:								
BLM	39.7	288	33.8	296	30.2	250	26.5	200
USGS	21.1	445	22.3	433	28.9	433	27.9	433
MMS	63.9	881	66.6	847	72.8	1014	75.4	1061
MMS/USGS C/	--	--	--	--	4.3	8	4.0	8
FWS	.3	6	.3	6	.3	6	.3	6
POCS	.5	10	.5	10	.5	10	.5	10
SOL	.4	13	.5	14	.5	14	.6	14
NPS	.1	2	.1	2	.1	2	.1	2
Total	126.0	1645	124.1	1608	137.6	1737	135.3	1734

Estimated Appropriations and Staff Requirements for Alternative IV-1 5-Year Leasing Program

Activity	FY 1982 A/ $ mil.	FY 1982 A/ FTE	FY 1983 $ mil.	FY 1983 FTE	FY 1984 $ mil.	FY 1984 FTE	FY 1985 $ mil.	FY 1985 FTE	FY 1986 $ mil.	FY 1986 FTE	FY 1987 $ mil.	FY 1987 FTE
Resource Info:												
USGS	10.8 B/	265 B/	11.8 B/	256 B/	17.0	256	17.0	256	17.3	256	17.3	256
MMS	29.4 B/	401 B/	32.9 B/	398 B/	41.6	550	42.6	570	43.1	580	44.8	590
FWS	.2	5	.2	5	.2	5	.2	5	.2	5	.2	5
Total	40.4	671	44.9	659	58.8	811	59.8	831	60.6	841	62.3	851
Exploration Data:												
MMS	2.3	5	2.3	5	2.4	5	2.4	5	2.5	6	2.7	6
Environ. Statements and Studies:												
BLM	35.0	141	33.1	160	37.4	160	27.2	145	21.2	135	16.2	110
USGS	8.9	140	9.1	138	15.5	138	15.5	138	16.0	138	16.0	138
MMS/USGS C/	--	--	--	--	4.3	8	4.0	8	4.5	8	2.5	4
Total	43.9	281	42.2	298	57.2	306	46.7	291	41.7	281	34.7	252
Supervise Lease Ops:												
MMS	30.6	472	29.8	443	32.9	453	34.8	480	36.8	505	36.8	510
Gen. Admin. Activities:												
BLM	4.7	147	5.8	184	6.2	192	5.0	191	4.4	181	3.1	171
USGS	1.4	40	1.4	39	1.4	39	1.4	39	1.4	39	1.4	39
MMS	1.6	3	1.6	3	5.0	6	4.7	6	4.5	5	4.2	5
FWS	.1	1	.1	1	.1	1	.1	1	.1	1	.1	1
POCS	.5	10	.5	10	.5	10	.5	10	.5	10	.5	10
SOL	.3	8	.3	9	.3	9	.4	9	.4	9	.4	9
NPS	.1	2	.1	2	.1	2	.1	2	.1	2	.1	2
Total	8.7	211	9.8	248	13.6	259	12.2	258	11.4	247	9.8	237
Summary:												
BLM	39.7	288	38.9	344	43.6	352	32.2	336	25.6	316	19.3	281
USGS	21.1	445	22.3	433	33.9	433	33.9	433	34.7	433	34.7	433
MMS	63.9	881	66.6	849	81.9	1014	84.5	1061	86.9	1096	88.5	1111
MMS/USGS C/	--	--	--	--	4.3	8	4.0	8	4.5	8	2.5	4
FWS	.3	6	.3	6	.3	6	.3	6	.3	6	.3	6
POCS	.5	10	.5	10	.5	10	.5	10	.5	10	.5	10
SOL	.3	8	.3	9	.3	9	.4	9	.4	9	.4	9
NPS	.1	2	.1	2	.1	2	.1	2	.1	2	.1	2
Total	125.9	1640	129.0	1653	164.9	1834	155.9	1865	153.0	1880	146.3	1856

Estimated Appropriations and Staff Requirements for Alternative IV-2 5-Year Leasing Program

Activity	FY 1982 A/ $ mil.	FY 1982 A/ FTE	FY 1983 $ mil.	FY 1983 FTE	FY 1984 $ mil.	FY 1984 FTE	FY 1985 $ mil.	FY 1985 FTE	FY 1986 $ mil.	FY 1986 FTE	FY 1987 $ mil.	FY 1987 FTE
Resource Info:												
USGS	10.8 B/	265 B/	11.8 B/	256 B/	17.0	256	17.0	256	17.3	256	17.3	256
MMS	29.4 B/	401 B/	32.9 B/	398 B/	35.8	550	36.8	570	37.3	580	39.0	590
FWS	.2	5	.2	5	.2	5	.2	5	.2	5	.2	5
Total	40.4	671	44.9	659	53.0	811	54.0	831	54.8	841	56.5	851
Exploration Data:												
MMS	2.3	5	2.3	5	2.4	5	2.4	5	2.5	6	2.7	6
Environ. Statements and Studies:												
BLM	35.0	141	33.1	160	37.4	160	27.2	145	21.2	135	16.2	110
USGS	8.9	140	9.1	138	15.5	138	15.5	138	16.0	138	16.0	138
MMS/USGS C/	--	--	--	--	4.3	8	4.0	8	4.5	8	2.5	4
Total	43.9	281	42.2	298	57.2	306	46.7	291	41.7	281	34.7	252
Supervise Lease Ops:												
MMS	30.6	472	29.8	443	32.9	453	34.8	480	36.8	505	36.8	510
Gen. Admin. Activities:												
BLM	4.7	147	5.8	184	6.2	192	5.0	191	4.4	181	3.1	171
USGS	1.4	40	1.4	39	1.4	39	1.4	39	1.4	39	1.4	39
MMS	1.6	3	1.6	3	5.0	6	4.7	6	4.5	5	4.2	5
FWS	.1	1	.1	1	.1	1	.1	1	.1	1	.1	1
POCS	.5	10	.5	10	.5	10	.5	10	.5	10	.5	10
SOL	.3	8	.3	9	.3	9	.4	9	.4	9	.4	9
NPS	.1	2	.1	2	.1	2	.1	2	.1	2	.1	2
Total	8.7	211	9.8	248	13.6	259	12.2	258	11.4	247	9.8	237
Summary:												
BLM	39.7	288	38.9	344	43.6	352	32.2	336	25.6	316	19.3	281
USGS	21.1	443	22.3	433	33.9	433	33.9	433	34.7	433	34.7	433
MMS	63.9	881	66.6	849	76.1	1014	78.7	1061	81.1	1096	82.7	1111
MMS/USGS C/	--	--	--	--	4.3	8	4.0	8	4.5	8	2.5	4
FWS	.3	6	.3	6	.3	6	.3	6	.3	6	.3	6
POCS	.5	10	.5	10	.5	10	.5	10	.5	10	.5	10
SOL	.3	8	.3	9	.3	9	.4	9	.4	9	.4	9
NPS	.1	2	.1	2	.1	2	.1	2	.1	2	.1	2
Total	125.9	1640	129.0	1653	159.1	1834	150.1	1865	147.2	1880	140.5	1856

Estimated Appropriations and Staff Requirements for Alternative V 5-Year Leasing Program

Activity	FY 1982 A/ $ mil.	FY 1982 A/ FTE	FY 1983 $ mil.	FY 1983 FTE	FY 1984 $ mil.	FY 1984 FTE	FY 1985 $ mil.	FY 1985 FTE	FY 1986 $ mil.	FY 1986 FTE	FY 1987 $ mil.	FY 1987 FTE
Resource Info:												
USGS	10.8 B/	265 B/	11.8 B/	256 B/	17.5	256	17.0	256	17.5	256	17.5	256
MMS	29.4 B/	401	32.9 B/	398 B/	36.6	550	37.6	570	38.1	580	39.8	590
FWS	.2	5	.2	5	.2	5	.2	5	.2	5	.2	5
Total	40.4	671	44.9	659	54.3	811	54.8	831	55.8	841	57.5	851
Exploration Data:												
MMS	2.3	5	2.3	5	2.4	5	2.6	5	2.6	5	2.7	5
Environ. Statements and Studies:												
BLM	35.0	141	35.4	160	40.0	160	27.7	145	21.0	135	16.0	110
USGS	8.9	140	9.1	138	16.0	138	15.5	138	16.0	138	16.0	138
MMS/USGS C/	--	--	--	--	4.3	8	4.0	8	4.5	8	2.5	4
Total	43.9	281	44.5	298	60.3	306	47.2	291	41.5	281	34.5	252
Supervise Lease Ops:												
MMS	30.6	472	29.8	443	32.9	453	34.8	480	36.8	505	36.8	505
Gen. Admin. Activities:												
BLM	4.7	147	5.8	184	6.2	192	5.0	191	4.4	181	3.1	171
USGS	1.4	40	1.4	39	1.4	39	1.4	39	1.4	39	1.4	39
MMS	1.6	3	1.6	3	5.0	6	4.7	6	4.5	5	4.2	5
FWS	.1	1	.1	1	.1	1	.1	1	.1	1	.1	1
POCS	.5	10	.5	10	.5	10	.5	10	.5	10	.5	10
SOL	.3	8	.3	9	.3	9	.4	9	.4	9	.4	9
NPS	.1	2	.1	2	.1	2	.1	2	.1	2	.1	2
Total	8.7	211	9.8	248	13.6	259	12.2	258	11.4	247	9.8	237
Summary:												
BLM	39.7	288	41.2	344	46.2	352	32.7	336	25.4	316	19.1	281
USGS	21.1	445	22.3	433	34.9	433	33.9	433	34.9	433	34.9	433
MMS	63.9	881	66.6	849	76.9	1014	79.7	1061	82.0	1095	83.5	1105
MMS/USGS C/	--	--	--	--	4.3	8	4.0	8	4.5	8	2.5	4
FWS	.3	6	.3	6	.3	6	.3	6	.3	6	.3	6
POCS	.5	10	.5	10	.5	10	.5	10	.5	10	.5	10
SOL	.3	8	.3	9	.3	9	.4	9	.4	9	.4	9
NPS	.1	2	.1	2	.1	2	.1	2	.1	2	.1	2
Total	125.9	1640	131.3	1653	163.5	1834	151.6	1865	148.1	1879	141.3	1850

A/ MMS estimates for FY 82 include general administrative expense costs. These are the only estimates that include such costs.

B/ Distribution of funds between MMS and USGS for FY 1982 and 1983 may change depending on yet-to-be resolved issues. The total will not change.

C/ Development and production EIS's (section 25(e)(1)) will be funded from resources allocated to both USGS and MMS, although this work relates primarily to MMS functions. No resources are now specifically identified for such EIS's in the FY 1982 appropriation or the FY 1983 budget.

APPENDIX 8

APPENDIX 8

ESTIMATES OF EXTERNAL COSTS

Summary

A quantitative analysis was made of some of the potential external costs* which might be associated with development of the recoverable hydrocarbon resources in each of the OCS planning areas. While the estimated external costs are associated with the development of the resources of each of the planning areas, they must be viewed as costs to the nation as a whole. This is so since the costs do not necessarily accrue to the residents living in areas adjacent to the planning areas on a one to one basis.

Of the potential OCS oil and gas damages that could occur, the analysis was restricted to those for which cost data (in dollars) exist and, in the judgment of the staff of the Interior Department, 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 are described in the FEIS, SEIS and in the SID. These descriptions, along with this external cost analysis, will allow the Secretary to consider variations in potential environmental damage and adverse coastal zone impacts from planning area to planning area in selecting the "timing and location of leasing."

In this analysis, estimates related to oil spills of 1000 barrels or more were made for potential ecological damages, tourism and recreation losses, commercial fishing losses, real property losses, legal expenses, subsistence life-style losses, the value of oil spilled, research and surveillance expenses, spill control and clean-up costs. Estimates were also made for potential air quality losses and onshore habitat losses. Damages from oil spills less than 1000 barrels and damages associated with transport of gas were not estimated for lack of data useful to this analysis. These damages, however, are expected to be modest in comparison to those estimated.

Estimates of the costs in each category of damage were based on data and judgments derived from the results of a literature search, the FEIS and final SEIS, the Appendix 10 analysis of relative environmental sensitivity and relative marine productivity, knowledge of the value of other uses of the sea, the estimated amount of oil and gas production, the likelihood of resulting damage in each area and a number of other factors. A description of the expected external cost analysis is presented in Appendix 8 and is summarized in Tables 8 and 9 below.

* External costs include environmental and socio-economic costs which are not normally included in the costs of operations involved in OCS oil and gas exploration, development, production and transportation.

Table 1 shows that the estimates associated with the development of the expected resource in each planning area range from a net total external benefit of $920 million to a net total external cost of $2.2 billion for the Central Gulf of Mexico and Diapir Field, respectively. Table 1 shows that external benefits are expected to result from the development of resources in the Central and Western Gulf of Mexico. This is the case since production of oil from these areas is piped to market and thus substitutes for or "backs out" imported oil which would otherwise be tankered to the United States and causes significantly greater expected oil spill damage.

Because the total expected external cost is a function of the amount of resource produced, the development of a planning area with a small amount of estimated hydrocarbon resources, such as Hope Basin or Shumagin, will in general, result in a relatively small total expected external cost. The converse is also generally true, with some exceptions which will be explained in the discussion of Table 2 below.

A comparison of the first column of Table 2 with Table 1 shows a number of differences between the ranking of the leasing areas by expected external costs per barrel of oil equivalent (BOE) compared to the total expected external costs. The Central and Western Gulf of Mexico are ranked lowest by both measures. Moreover, these two areas are expected to provide 92 cents and 45 cents per BOE, respectively, of external benefits to the nation as a whole. On the other hand, the estimated resources of the Eastern Gulf of Mexico and Central and Northern California would be expected to be the most expensive to develop with respect to the expected external costs per BOE accruing to the nation as a whole (53 cents and 44 cents per barrel, respectively).

The following observations can be made from the analysis of this Appendix as summarized by Table 2. If none of the area's oil resources are expected to be transported by tanker (e.g., Central and Western Gulf of Mexico), an external benefit is expected to result rather than an expected external cost. For an area in which a small percent of the hydrocarbon resources is expected to be oil, the expected external costs per BOE are relatively low even if all the oil is transported by tanker (e.g., Hope Basin--see 1st and 2nd columns of Table 2). Likewise, even if the percent of hydrocarbons which are expected to be oil is high, the expected external costs per BOE are expected to be relatively low if a large portion of the oil is not transported by tanker (e.g., Southern California). For an area in which a high percent of the estimated hydrocarbon resources is expected to be oil, and all the oil is expected to be transported by tanker, the expected external cost per BOE is expected to be relatively high (e.g., Eastern Gulf of Mexico--see 1st and 2nd columns of Table 2). These observations help demonstrate that of the potential damages examined in the analysis, the dominating influence in determining the expected external cost per BOE is the expected damage from transportation of oil by tanker. The analysis shows that about twenty times more oil per barrel transported is expected to be spilled from tankers than from pipelines. As such, the external costs associated with damage from oil spills from tankers far overshadow all other sources of damage considered in the analysis.

Table 1
OCS Planning Areas Ranked by
Total Expected External Costs
(Environmental and Socio-Economic) in $ Billion
Associated with Development of All the
Resources In Each Planning Area

	Expected External Costs of Development of Expected Recoverable Resources ($billions)
1. Central Gulf of Mexico	- .92 *
2. Western Gulf of Mexico	- .45 *
3. Hope Basin	.01
4. Shumagin	.06
5. Cook Inlet	.08
6. Norton Basin	.12
7. North Aleutian Basin	.14
8. North Atlantic	.18
9. Kodiak	.25
10. Gulf of Alaska	.27
11. St. George Basin	.34
12. South Atlantic	.38
13. Southern California	.40
14. Navarin Basin	.45
15. Central and Northern California	.46
16. Barrow Arch	.55
17. Eastern Gulf of Mexico	.69
18. Diapir Field	2.22
(Old North Atlantic)	(.02)
(Old Mid-Atlantic)	(.13)
(St. Matthew-Hall)	(-)

* A negative expected external cost, e.g. -$.92 billion dollars, indicates a gain rather than a loss in those resources and values analyzed. Such net benefits result and accrue to the nation as a whole when the external costs associated with development of the area's resources are less than the oil spill costs foregone from "backing out" foreign crude oil imported in tankers. For further explanation of costs foregone from foreign imports see Appendix 8-D-0.

Table 2

OCS Planning Areas Ranked by Expected External Cost In $ Per Barrel of Oil Equivalent (BOE)

		External Cost in Dollars Per BOE	Percent of BOE Which Is Oil	Percent of Oil Transported At Least Part of Route By Tankers
1.	Central Gulf of Mexico	-.10 *	34	0
2.	Western Gulf of Mexico	-.07 *	24	0
3.	North Atlantic	.03	57	67
4.	Southern California	.17	76	50
5.	Hope Basin	.20	29	100
6.	South Atlantic	.24	60	100
7.	Navarin Basin	.24	47	100
8.	Norton Basin	.32	42	100
9.	Shumagin	.33	44	100
10.	Cook Inlet	.36	43	100
11.	Kodiak	.36	49	100
12.	St. George Basin	.37	50	100
13.	Gulf of Alaska	.39	50	100
14.	North Aleutian Basin	.40	54	100
15.	Diapir Field	.41	51	100
16.	Barrow Arch	.43	55	100
17.	Central and Northern California	.44	80	75
18.	Eastern Gulf of Mexico	.53	83	100
	(Old North Atlantic)	(.01)	(58)	(67)
	(Old Mid-Atlantic)	(.03)	(57)	(67)
	(St. Matthew-Hall)	(-)	(-)	(-)

* A negative expected external cost, e.g. -10 cents per BOE, indicates a gain rather than a loss in those resources and values analyzed. Such net benefits result and accrue to the nation as a whole when the external costs associated with development of the area's resources are less than the oil spill costs foregone from backing and foreign crude oil imported in tankers. For further explanation of costs foregone from foreign imports see Appendix 8-D-0.

This Appendix also demonstrates that of the potential expected external costs which were measured, the greatest portion is expected to be attributable to possible ecological damage from large oil spills reaching the coastal zone. In fact, potential ecological costs are expected to be several times greater than external socio-economic costs.

Ecological losses from oil spills are generally expected to be higher per barrel of oil when tankers are used to transport oil to shore and when spills are more likely to hit a coastal area with valuable, oil-sensitive ecological resources. This is so, due to the expected spill rate for tankers and because ecological damage, should a spill occur, is expected to be greater nearshore and onshore than in the open ocean and greater in coastal areas with economically valuable, oil-sensitive resources than for areas with relatively barren shores and nearshore waters. Also, the amount of oil spilled is expected to be roughly proportional to the amount of oil produced and transported. Thus, the expected amount of the oil resource, the distance of the oil platform from shore, the value and sensitivity of potentially threatened ecological resources, and the mode and route of transport are four of the prime factors which determine the magnitude of expected external costs of spills over 1000 barrels in this analysis.

Ecological costs per barrel of oil spilled for spills over 1000 barrels from platforms are expected to be relatively low for Navarin Basin and the North Atlantic due to the relatively low occurrence of sensitive, valuable habitats and the relatively low chance of spills reaching them. The corresponding ecological costs are expected to be moderate for the South Atlantic and moderate to high for all the other planning areas (See Appendix 8-C-1). However, when the total expected ecological costs of production are considered, the development of the resources of Central and Western Gulf of Mexico are expected to result in lowest costs of all the planning areas because no tankers are anticipated to be used for transport of these resources. The North Atlantic and Southern California are expected to have moderate total ecological costs due in part to use of pipelines rather than tankers for transport of some of the estimated oil resources. The other planning areas are expected to have moderate to high total ecological costs on a relative basis. (See Appendix 8-C-1).

Expected socio-economic costs, while small relative to ecological costs, vary considerably depending on the leasing area. For instance, recreation losses caused by oil spills from platforms are expected to be relatively high per barrel for Southern California, relatively low in the Alaskan areas and moderate elsewhere. Also, expected losses to subsistence life-styles are significant in some areas of Alaska but assumed to be negligible outside Alaska. The expected cost of oil spill control and clean-up varies considerably from area to area, too. (See Appendix 8-C-1.)

Losses per barrel due to air pollution were assumed to be negligible in all the Alaskan areas except Norton Sound, where they are estimated to be very low. Air pollution losses in areas of the contiguous 48 States range from relatively low to moderate except for the California areas, where they are expected to be relatively high per barrel, due in large part to the concentrated coastal population and the climate. (See Appendix 8-C-2.)

Wetland habitat losses from onshore development are expected to be relatively large for Barrow Arch and somewhat less for all the other areas except the North Atlantic, the Central and Western Gulf of Mexico and the California areas, for which such losses are expected to be quite small on a relative basis. The key determinants of these estimates are the percent of onshore support areas expected to be located in wetlands, the degree to which support facilities exist, and the amount and duration of onshore support activity. (See Appendix 8-C-2.)

The above discussion and the estimates given in this Appendix must be considered in light of two important points. First, the estimates may largely overstate the costs, and second, due to the high uncertainty, the estimates must be used cautiously. The estimates were made to comply with Section 18 of the OCSLA and the opinion of the Circuit Court of Appeals of the District of Columbia in California vs. Watt, dated October 6, 1981. They were made using an "uneasy calculus" as the Court recognized might be necessary.

When judgments were needed on the dollar value to use for damages or how an area's environmental resources should be rated, the practice was always made to err on the high side. For instance, ecological damages are difficult to assess and even more difficult to value in terms of dollars. The same is the case for subsistence losses. As explained below, in attempting to solve these difficult quantification problems, costs probably have been overstated.

Another and vitally important reason that the estimates of expected external costs are likely overstated is that development of the United States' OCS oil and gas resources is conducted in an exceedingly safe and environmentally sound manner. The program has, compared to other developmental programs, an outstandingly low record of personnel and mechanical failures which have resulted in environmental damage or adverse coastal zone impacts. Advances in technology have lowered and can be expected to continue to lower the chance of such damage and impacts. The substantial OCS oil and gas scientific program of the Department of the Interior 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 Interior Department have mitigated and will continue to mitigate many of the potential damages. Furthermore, the compensation provisions of the OCS Lands Act (while not reflected in this external cost analysis) provide a means to compensate those who are adversely affected in the event that damage occurs.

As indicated above, the other important point which must be kept in mind in assessing the results of this analysis is 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 and opinion, the external cost estimates should be considered, at best, as an order of magnitude approximation. As such, prudent use of these estimates would only make distinctions between differences from area to area if they are approximately an order of magnitude in size (that is, one estimate is more than or less than 10 times the other). For instance, it would be reasonable to regard the development of the resources of the Hope Basin, Shumagin, Cook Inlet, Norton Basin, North Aleutian Basin and the North Atlantic as having significantly lower total external costs than development of the resources of Diapir Field. Such a conclusion is reasonable because the external cost estimates differ by two orders of magnitude (e.g., $12 million vs. $2 billion - see Table 1). On the other hand, to presume that the total external costs associated with the development of the resources of Eastern Gulf of Mexico will be significantly higher than those associated with the Gulf of Alaska would be, at best, a marginally credible presumption.

Analytical Approach

The basic approach used for the expected external cost analysis was as follows:

(1) First, generic ranges and averages for measurable damages from spills of 1000 barrels or greater in $ per barrel were developed (see Appendices 8-A and 8-B). Then estimates were made of specific values for spill damages for each of the planning areas. These estimates are given in dollars per billion barrels of oil expected to be produced. Estimates of air pollution and wetland habitat losses were also made. These estimates are given in dollars per billion barrels of oil equivalent (BOE)* expected to be produced. Appendices 8-A, and 8-B, 10, the EIS, as well as other source information, were used in estimating regional variations in costs per barrel. These costs per barrel were then organized into tables, giving all cost data in dollars adjusted to present value estimated for July 1981, (see Appendices 8-C-1 and 8-C-2).

(2) The data were then adusted to present value estimated for July 1982. Then, these adjusted values wre combined with data on expected hydrocarbon resources (see Appendix 2) to calculate total expected external costs associated with exploration and production of all the expected resources estimated to be in each planning area. The result was a "common-base" total expected external cost table (see Appendix 8-D-0) constructed on the hypothesis that all the resources of each leasing area would be leased in mid-1982. The hypothesis is an analytical necessary to compare planning areas and to serve as a base for comparing the estimated external costs of leasing schedule alternatives.

(3) Total expected external costs given in Appendix 8-D-0 were then adjusted to reflect each leasing schedule alternative. See Appendices 8-D-1 through 8-D-6.

---

* One BOE equals one barrel of oil which equals 42 U.S. gallons of oil which equals the fuel equivalent of 5620 cubic feet of gas. To convert cubic fee of gas in trillions to barrels of oil in billions, divide the volumne gas by 5.62.

Explanation of External Costs

Expected external costs are estimates of the costs of development of the hydrocarbon resources which are not reflected in the market cost of OCS oil and gas operations. They are estimates of the environmental and socio-economic costs expected to result if the estimated resources were developed and brought to shore. These costs are viewed from a national perspective, not a local perspective and thus the total expected costs borne by a region are not explicitly indicated in this analysis. For example, potential costs of spills from tankers transporting Alaskan oil to California would be expected external costs associated with development of the resources of the Alaskan planning area, but would be borne by citizens of Alaska and California and to a lesser degree Washington and Oregon.

Even if damages occur in the region in which the hydrocarbon resources are discovered, they are not necessarily borne by the citizens of that region. If, for example, the affected region receives compensation from a national oil spill liability fund, other elements within the nation may pay the cost of clean-up. Finally, external cost estimates do no include the cost of equipment for development of the resources, nor the cost of labor, nor any losses caused by a shortage of labor in a competing industry such as commercial fishing where wages may not be as high as those paid by oil and gas development industries.

Method of Calculation

The method used to estimate oil spill costs on a per barrel basis is explained step by step in Appendix 8-C-1. The results are then used in Appendix 8-C-2 and 8-D-0 to estimate the total oil spill costs expected for each leasing area using the hypothetical assumption that all the estimated oil and gas resources were leased in mid-1982 and then developed.

Similarly, the methods used to estimate air quality losses and habitat losses from onshore activities on a per barrel basis are shown in Appendix 8-C-2. The results are then used in Appendix 8-D-0 to estimate total air quality losses and total habitat losses expected for each leasing area if all the estimated resources were developed.

The estimates of per barrel costs and total costs for each leasing area are summarized in Tables 1 and 2 of this Summary.

Sources of Data and Information for Estimates

The data and information used as a basis for making these estimates was taken from:

the FEIS;

the final supplemental to the FEIS;

the relative environmental sensitivity of OCS planning areas (Appendix 10);

relative marine productivity of OCS planning areas (Appendix 10);

a Fish and Wildlife Service memorandum entitled "Request for Assistance, Generic Damage Assessment" (Appendix 8-A);

- a "Social and Economic Impact Matrix" developed by the Bureau of Land Management (Appendix 8-B);
- a variety of other references, many of which are cited in subsequent sections of this Appendix; and
- opinions by experts in the Department of Interior.

The initial estimates derived from the above sources were reviewed by specialists from the Bureau of Land Management, the Fish and Wildlife Service and the staff of the Assistant Secretary for Policy, Budget and Administration and modified where necessary so that the external cost data represents the Interior Department's best professional judgement.

Reliability of External Cost Estimates

A thorough search of the literature shows that very little source data exist on external costs associated with OCS oil and gas development. In particular, very little data exist on the costs of large oil spills associated with development of the OCS resources of the United States, mainly because there have been few such spills. There are even less source data available which show how OCS oil and gas related external costs vary from planning area to planning area and from one coastal zone area to another. Nevertheless, Section 18(a)(3) requires that the Secretary ...

> "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 reviewing this and the other requirements of Section 18, the Circuit Court of Appeals of the District of Columbia acknowledged that the OCS Lands Act Amendments require the Secretary to prepare a 5-year program in a manner which may require use of an "uneasy calculus" potentially competing economic, environmental and coastal state concerns. The calculus did indeed prove to be "uneasy". Nevertheless a quantification of the "potential for ... environmental damage [and] impact on the coastal zone" was deemed desireable in order to provide the Secretary with another tool to be used "to obtain a proper balance". The estimates of some of the external costs of OCS oil and gas development in this analysis were developed to be considered by the Secretary along with the FEIS, SEIS, and other parts of SID to assist him in obtaining that balance. However, scientific and statistical methods needed to provide highly reliable estimates of external costs could not be used in most cases given the paucity of hard information and data. Furthermore, since external costs are by and large a function of development and production, the uncertainty in estimates of external costs increases with the uncertainty of the resource estimates.

The net effect of the uncertainty was to force Interior Department experts to supplement source data with their best professional judgement in order to make the estimates needed to satisfy the requirements of Section 18. Also, whenever a lack of sufficient data required that an assumption be made as to the dollar value of an external cost, estimates were made to err on the high side. As such, the estimates likely overstate the external costs.

As mentioned earlier in the Summary, the external cost estimates of this analysis should be considered only as order of magnitude estimates. Presumptions about differences which are much less than an order of magnitude may lead to marginally reliable conclusions.

APPENDIX 8-A

Generic Damage Assessment
Ecological and Habitat Impacts

ADDRESS ONLY THE DIRECTOR, FISH AND WILDLIFE SERVICE

United States Department of the Interior

FISH AND WILDLIFE SERVICE
WASHINGTON, D.C. 20240

JAN 20 1982

Memorandum

To: Assistant Secretary - Policy, Budget, and Administration

Through: Assistant Secretary for Fish and Wildlife and Parks FEB 1 1982

From: Director, Fish and Wildlife Service Robert A. Jantzen

Subject: Request for Assistance, Generic Damage Assessment

In response to your request, the Fish and Wildlife Service's Office of Biological Services prepared the attached report which attempts to document the damages of oil spills and the unit costs of those damages based upon a review of the existing literature. This report supplements the assistance which OBS provided to BLM and PBA in determining the relative marine productivity and environmental sensitivity of OCS planning areas. In order to meet your December 24 deadline, an advance copy of this report was forwarded to staff in PBA.

Please let me know if you have any questions concerning this report, or if you desire further assistance.

Attachment

Introduction

On December 4, 1981, the Assistant Secretary, PBA, requested assistance from the Fish and Wildlife Service's Office of Biological Services (OBS) to provide information relating to environmental damages and costs associated with offshore oil and gas production on the Outer Continental Shelf (OCS). Following that request, Service staff have worked directly with staff of BLM, POCS, and PPA to define and identify marine productivity and environmental sensitivity. In addition, OBS was asked to review relevant information on the damages of oil spills and other aspects of OCS development upon biological resources, and determine, describe and quantify, if possible, the measurable and immeasurable costs. The information on damages and their costs was requested for no later than December 24, 1981. This report is a summary of the results of that task.

The review of environmental damages and costs was directed toward complying with certain specific requirements of the OCS Lands Act (OCSLA), as amended in 1978, and the recent opinion of the Appellate Court regarding the Department's 5-year OCS oil and gas lease program. In complying with the request, we performed the following tasks:

i) We initiated and are continuing a literature review on damages resulting from oil spills and other aspects of OCS oil and gas production.

ii) We relied in part upon data from experts to augment the literature review. Specifically, we sought data from persons with specific knowledge of oil spills, the oil spill literature, and of marine and coastal ecosystems. We utilized personnel from NOAA, Department of Energy, EPA and academia, as well as BLM and Service personnel in our review and quantification.

iii) Based on these sources and data, we have attempted to focus on the extent of damages associated with OCS oil and gas production. We have attempted to describe damages in three ways:

(a) a qualitative description of spill and non-spill damages by resource,

(b) a quantitative description of damages, where available, by resource, and

(c) a quantitative description of damages by spill.

This is obviously a complex undertaking and there are no simple answers to the questions asked. There are great controversies and differences of opinion regarding the effects of oil operations on biological resources. In addition, the task of quantifying damages, even if accurately described, is also subject to great differences of opinion. There are no commonly accepted techniques or results for such efforts. Therefore, a large amount of uncertainty or imprecision is inherent in the conclusions. The report which follows is only a summary of the results and important basic assumptions presented in a brief, almost telegraphic style.

Basic Assumptions

During the course of our review - and central to any ultimate balancing of costs and benefits - several assumptions were made. These include:

1. The estimated or projected oil spill and non-spill damage from OCS oil and gas operations will be a function of several factors, including (among others):

    - the volume of oil produced (which will affect the probability of a spill, the amount spilled, and the number of platforms, pipelines, and other structures).

    - the statistical means for projecting the frequency and size of spills.

    - the statistical means for projecting trajectories if a spill occurs.

    - the type of oil (toxicity and weathering/dispersion vary with different crudes).

    - abiotic factors, such as the distance offshore, the season, and the region of the spill (which affect the weathering of oil, its dispersal, biological recovery rates, likelihood of hitting coastal areas, etc.).

    - the kinds of resources struck by oil or affected by non-spill activities.

    Our task has been limited to just the last factor: identifying, describing, and assessing the damages to specific resources in as quantitative terms as possible.

2. Given that there is uncertainty or imprecision involved in each of the factors above, it is unnecessary and undesirable to

attempt to describe or delimit one factor in terms which are orders of magnitude more precise than other factors. In other words, given large uncertainty in several of the steps, increasing the level of precision in one factor will not significantly enhance the accuracy of the final product.

3. In reporting damage, we have attempted to rely on published scientific reports, and to avoid speculative or non-documented assertions of damage or non-damage. Where there is valid documentation of damage, but uncertainty as to cause (i.e., a causal relationship between death and an oil spill has not been firmly established), we have tended to be conservative and include such damages in establishing the range of damage.

4. Because the data are so sparse, we have included impact data from oil spills from tankers and from spills of refined products as well as crude. We recognize that the impacts of different refined products on biological resources vary, as do the impacts of different crudes, but we feel that they can be helpful in establishing a range of potential impacts.

5. It is probable that damage has been underreported. This is because:

   i) Some damage will be masked by natural variations of species, population size and distribution. The inability to measure damage does not mean it has not occurred: it reflects more accurately on the inadequacy of our sampling methods and background knowledge.

   ii) Dead organisms are hard to sample. Small forms decompose rapidly, and may be carried far from spilled oil by subsurface currents, or sink to lower water levels.

   As a general rule, the Service has concluded that for each dead bird counted or identified in a pollution incident, two more have died and will never be found. Similar ratios might be expected for fish and marine mammals.

6. In order to assess damages or costs, the extent of damage, its duration (time to recovery) and the value of the resource(s) affected must all be considered. Losses must be discounted to reflect present value.

Conclusions

1. For a variety of reasons (described by many authors), the assessments of oil and gas related damages vary considerably. This variation reflects differences in spill conditions (biotic and abiotic);

in understanding of background (pre-damage) conditions; in analytical design and approach (post-spill assessments); and other complicating factors. Thus, it is difficult to describe any damage with any degree of certainty, and even more difficult to generalize the results of such incidents to future situations.

2. Although the effects of spills a) vary greatly, b) are disputed widely, and thus c) are difficult to generalize, they are no less imprecise than other factors which affect the potential for damage (i.e., USGS's estimates of oil reserves, the projected spill trajectory and chance of hitting resources if a spill occurs, etc.). Because there is no value in providing greater precision at this time, certain generalizations can be made and disputes over exact quantification of damage can be avoided. Greater precision regarding damages is unnecessary for this purpose.

3. There has been no significant impact from OCS oil and gas operations identified on commercial or recreational fish, other fish, plankton, and the oceanic habitat in general. We have examined both negative and positive (artificial reef effect) impacts from spills and operations, and have concluded that any effects are localized and short-term, with rapid biological recovery. Whatever effects have occurred have been masked by natural variation.

   Fishing - not fish - has been affected both by spills and non-spill operations. This, however, is a socio-economic impact, not biological, and should be addressed elsewhere.

4. The spill effects increase in shallow waters and low-energy environments, particularly in enclosed estuarine systems.

5. Spills may cause dramatic, large-scale and widespread mortality in seabirds and waterfowl. The Santa Barbara blowout killed about 25% of the local population of seabirds resident at the time of the spill, and some earlier reports approach 90% mortality of colonies. There is some indication that breeding success may be depressed (30% reduction 2 years after the spill in Torrey Canyon), but in general the populations seem to rebound rapidly (2 years or less) (See Tables 1 and 2).

6. Damage from oil spills may be severe and long-term in low energy intertidal environments such as tidal flats, salt marshes, and mangroves. Spills can effectively destroy the habitat and associated fauna, and biological recovery may exceed 2 to 10 years or longer (Table 3). It is probable that recovery is in the higher part of this range (7 years or more).

7. Depending on tidal cycle and other factors, coral reefs may be significantly affected by spills, which can directly cause mortality

TABLE 1

Summary of Some Incidents of Oil Spills and Bird Kills
(Updated from Kash, et al., 1973)

Date	Source	Location	Product (BBL's)	Birds Killed	Species	Birds/BBL Spilled
1907	Tanker	England	50,000 crude	up to 100,000	Puffins	2
1937	Tanker	San Francisco	70,000 crude	10,000	Shorebirds & Murres	0.14
1952	Tankers	Massachusett	150,000 "oil"	up to 30	Eiders	2
1966-67	75 incidents	Alaska	1,000 "oil"	1,200-2000	Ducks	1.2-2.0
1966	Tanker	England	10,000 crude	2772	20 Spp.	0.28
1967	<u>Torrey Canyon</u>	England	700,000 crude	at least 30,000	Auks, Razorbills, Puffins, Gulls, Cormorants	0.04
1969	Rig blowout	Santa Barbara	70,000-140,000	at least 3600 (25%)	Grebes, Cormorants Mergansers, Pelicans and Loons	0.06-0.03
1969	Tanker	Scotland	1,000 + crude	20,000	Eiders, Scotors, Auks, others	20
1971	Tankers	San Francisco	20,000 Bunker C	7,000	Sea and Shore-birds	0.35
1976	<u>Argo Merchant</u>	Massachusetts	180,000 No. 6 oil	at least 540	-	0.003
1976	<u>Barge STC-101</u>	Chesapeake Bay	6,000 No. 6 oil	10,312 counted (30,936 estimated)	-	1.72 (5.16)
				range	0.003 - 20 birds killed/ BBL Spilled	

Discarding high and low extremes, range = 0.03 - 5.16

Table 2
SUMMARY OF IMPACTS OF
MAJOR OIL SPILLS ON LIVING RESOURCES

RESOURCE	EFFECTS
Plankton - oceanic (phytoplankton & zooplankton)	- some localized and temporary contamination possible - mortalities and deformed embryos reported from Argo Merchant - natural variation and patchiness in distribution exceeds that caused by oil. - very fast recuperation due to natural distribution and reproduction - possibly significant in constricted areas with highly seasonal growth (i.e., open leads in Arctic ice). (0% loss)
Plankton - coastal & estuarine	- expect effects to be more significant than in oceanic areas, concentrated by shallow depth, mixing throughout water column, and constricted circulation - recuperation for most species within one year (5% loss of affected resources for 1 year)
Fish & Shellfish - oceanic	- some localized contamination reported: Argo Merchant - no reported mortality - fast recovery (0% loss)

Table 2
(Continued)

Fish & shellfish - coastal & estuarine	- some contamination and mortality, particularly in shallow water shellfish (*Amoco Cadiz*; West Falmouth) - duration of impacts usually short for fish, slightly longer for shellfish, especially if sediments are contaminated - shellfish may concentrate contaminants - non-lethal contamination of shellfish may persist 7-10 years (West Falmouth: refined product); organisms live, but non-edible (i.e., socio-economic impact) (15% loss, 1 year)
Pelagic seabirds Waterfowl Coastal birds	- may have widespread contamination and mortality, especially to diving birds and those which float on surface. - recovery usually within 1-2 years (60% loss of affected population for 1 year, 30% for 2 years)
Marine mammals and Endangered Species	- varies greatly by species (sea otter - loss of 100% affected individuals for 25 years whales - no probable loss turtles - 70% loss of eggs on oiled beach 20% loss of adults for 7 years)

(Note: Estimates in parentheses are based on relative impacts. May vary within one order of magnitude)

Table 3
SUMMARY OF IMPACTS OF MAJOR
OIL SPILLS ON HABITATS

Oceanic - benthic & pelagic Coastal - pelagic	Oil widely distributed and diluted; impacts very short-term primarily to surface species (especially waterfowl); recovery rapid.
Coastal - benthic	Small-to-large fractions of oil may settle upon or be entrained into bottom sediments; impacts generally short-term, recovery rapid.
Subtidal Seagrasses	Little damage reported, recovery very rapid.
Coral reefs	Effects especially varied; may be acute, particularly to shallowest reefs. High mortality, recovery 2-10 years. Oiling may greatly increase susceptibility to other stresses (Loya and Rinkevich, 1980).
High Energy Intertidal: rocky shores and cobble beaches	Damage may be widespread, but recovery usually rapid. Long-term changes (5-7 years) in community structure may result (Torrey Canyon: crude and emulsified).
Medium Energy Intertidal: Sand and gravel beaches	Damage may be widespread, recovery usually rapid. 80-95% of surf clams destroyed, but recovery within one year (Ixtoc).
Medium - Low energy exposed tidal flats and sheltered rocky shores	Damage may be widespread, recovery moderate (1-5 years).
Low-energy intertidal sheltered tidal flats, salt marshes, mangroves	Damage may be widespread and large-scale, with oil and its effects very persistent. Maximum damage may not be apparent for 2 years. Recovery 2-10 years or longer (Metula, Zoe Colocotroni, Amoco Cadiz).

and also increase the susceptibility of reef organisms to death from other stress sources. Recovery may exceed 5-7 years (Table 3).

8. It is difficult to generalize the effects of spills on endangered species; each must be individually assessed. In general, the effects will be greater on species which rely on fur for insulation (sea otter, polar bears, fur seals) than on those relying on blubber (whales, manatees, sea lions). Because of several factors, sea otters would appear to be particularly susceptible to spills; whales do not seem susceptible; whales and manatees may be able to detect and avoid oiled waters. Turtles are also particularly susceptible to oil, especially nests on beaches. It may be safe to assume 100% mortality for sea otters and sea turtles contaminated by oil (Table 2).

9. Some species, such as migrating pelagic seabirds, are particularly vulnerable at certain times of the year when essentially the entire population of a species is grouped and passing through a particular location at the same time. Calculations of risk for these species should address the high risk for such periods of time.

10. Non-spill impacts of particular consideration are:

    a. Support operations: crew boats and helicopters cause noise which affects bird and marine mammal rookeries.

    b. Platform placement and discharges:

       Mackin reported decreased plankton diversity around brine discharges in the Gulf of Mexico, and recent reports show a decline in biological diversity and productivity around platforms in the North Sea. These represent localized effects (3-5 km radius), resulting in 10-50% loss of planktonic and benthic resources, for a long period of time (30 years or life of platform). Coral reefs would be particularly susceptable.

    c. Dredging for access canals, pipelines, and support facilities, causes loss of wetlands, changes in freshwater/salt water patterns, and turbidity. Estimates as high as one half of the annual wetland loss (about 25,000 acres per year) in Louisiana have been attributed to oil and gas activities. Of this amount no more than about 10-15% (1200 to 1800 acres per year) may be the result of OCS oil and gas activities.

    d. Seismic Surveys - some concern has been expressed about the impacts on endangered species, particularly seals and polar bears. There is also some speculation that it may have behavior impacts on whales, and could be especially important when they are concentrated, such as during migration.

e. Chronic discharges of oil - due to a lack of solid baseline information it is generally difficult to assess the impacts of chronic spills. At least in coral reefs (in the Red Sea) the impacts of chronic small spills seem to be more significant than those of major spills.

11. Once impacted, some habitats, particularly coral reefs and marshes and mangroves, may never recover to the same community structure. We can not quantify changes in communities (loss of one resource and replacement by another).

12. Given the levels of uncertainty and imprecision in the other factors affecting spill risk - particularly the oil and gas resource estimates and the spill trajectory projections - we recommend that the effects of oil spills on resources (other than endangered species), and on specific habitats be treated as a constant for purposes of regional comparisons. We recognize that the effects of oil spills and extent of damage on cod, salmon, king crab, and menhaden, for example, would all be different; yet the magnitude of the differences will be less than the magnitude of uncertainty regarding, for one example, OCS resources (and thus spill probability). Similarly, the biological damage to a salt marsh could be assumed to be identical whether the marsh were in California, Florida, or Maine.

    This generalization will simplify the regional comparisons by avoiding having to quantify impacts on a species by species basis (impossible given existing knowledge). Thus, regional comparisons can be made solely on the basis of a) estimated reserves, b) spill probability, c) strike (trajectory) probability, d) the quantity of biological resources or habitat available and e) the value of those resources.

13. As indicated, there are no commonly accepted means of evaluating biological resources. We suggest the following:

    Fish and Shellfish:

    Value based on ex-vessel value, summed for all species caught in the region.
    Since not all commercially valuable fish are caught, use the NOAA FCMP data to project total population size and total value (foreign and domestic).
    Apply same value ($/ton) to (a) unharvested individuals of commercially valuable species based on FCMP data, and (b) unharvested species.

    Plankton: Aggregate total production by tons, and use 1/10th of the commercial fish value on an equivalent per weight basis.

    Birds: Use table of values (Table 4) generated by FWS for STC-101 spill, augmented by endangered species values (Table 5).

    (NOTE: BLM is compiling data on population estimates)

TABLE 4

ESTIMATED COST FOR LOST WATERFOWL

AS A RESULT OF THE CHESAPEAKE BAY OIL SPILL

Species	Number of birds counted (note a)	Estimated cost per bird (note b)	Total cost
Grebe (note c)	4,686	$ 10	$ 46,860
Loon (note c)	216	10	2,160
Oyster Catcher (note c)	1	10	10
Ringbill Gull (note c)	3	10	30
Herring Gull (note c)	43	10	430
Cormorant (note c)	10	10	100
Great Blue Heron	2	25	50
Sea Gulls (note c)	2	10	20
Old Squaw Duck	4,079	25	101,975
Ruddy Duck	117	40	4,680
Bufflehead Duck	177	75	13,275
Goldeneye Duck	111	75	8,325
Coot	1	20	20
Surf Scoter	586	25	14,650
Whitewing Scoter	8	75	600
American Scoter	20	75	1,500
Widgeon	2	25	50
Canvasback Duck	12	75	900
A. Merganser	16	25	400
Red Breasted Merganser	2	25	50
Whistling Swan	63	200	12,600

TABLE 4
(continued)

Species	Number of birds counted (note a)	Estimated cost per bird (note b)	Total cost
Black Duck	12	$ 25	$ 300
Bluewing Teal	3	15	45
Pintail Duck	1	10	10
Canada Geese	8	25	200
Black Brant	2	50	100
Red Bead Duck	40	25	1,000
Greater Scaup	24	35	840
Greenwing Teal	1	15	15
Rail	2	25	50
Mallard Duck	1	10	10
Unknown (note c)	61	10	610
Total	10,312	-	$211,865
Using weight factor (note d)	x 3	-	x 3
	30,936	-	$635,595

a/Bird count by Water Control Board, Commonwealth of Virginia.

b/Estimated cost by Fish and Wildlife Service, Department of the Interior.

c/For species which did not have a fair market value or cost of replacement, we used the least amount for which a fair market value and/or replacement cost was determined.

d/Wildlife experts from the National Audubon Society and the Fish and Wildlife Service estimated birds killed by the spill would be three times the actual count; i.e., for every bird counted, two birds would (1) die or not be washed ashore, (2) be eaten by predators before they could be counted, or (3) wash or crawl into inaccessible areas.

(Source: U.S. General Accounting Office. 1977. Total costs resulting from two major oil spills. Report of the Comptroller General of the United States. CED-77-71. June 1, 1977).

(Value in 1977 (?) dollars).

TABLE 5

BLACK MARKET VALUES OF SELECTED ENDANGERED SPECIES (1981)

Bald Eagle	$300
Peregrine Falcon	500-1000 domestic 5000-10,000 international
Leatherback, Green, Ridley and Hawksbill Sea Turtles	200-500
Alligator	200-400
Crocodile	200-400
Sea Otter	300-600
Polar Bear	2000-4000
Walrus	400-600
Seals	30-50

Marine Mammals and Endangered Species:

These are probably the hardest to evaluate. One simple measure (not related to biological value, but reflecting scarcity) is the black market value, where it exists. Table 5 provides estimates provided by FWS Law Enforcement.

Bowhead Whales could be valued at cost of replacing food, or actual whaling expenditures:

(a) Average bowhead yields 14,000 lbs meat, valued at $5/lb = $70,000/whale;
(b) 100 whaling boats at $10,000 annual cost, to harvest 24 whales = $42,000/whale.

Habitats:

Coral Reefs - user willingness to pay or actual expenses.
Others - See Table 6

14. Some spills have been subjected to rigorous - though controversial - economic analyses of environmental damage. A summary of these is provided in Table 7. The range of damages, based on estimates and court awards, is $22-2074 (1979) per barrel of oil spilled.

TABLE 6

Values of Coastal Habitats

Type	Year	Basis	$/Acre	Reference
coastal marsh	1974	total life support	4,100 per annum	Gosselink, et al., 1974
coastal marsh	1977	economic return	500 per annum	Rapheal and Jaworski, 1979
coastal marsh	1981	total goods and services	3,000-30,000	Lynne et al., 1981
coastal marsh	1979	gross primary production	500-700 per annum	Costanza, 1981
mangroves	1977-1980	creation	2,800-534,000	Lewis, 1981
bays and estuaries	1979	gross primary production	40 per annum	Costanza, 1981
bays and estuaries	1973	commercial fisheries	500	Tihansky and Meade, 1976
aquatic beds	1980	creation	2,000-50,000	Thorhaug, 1980
barrier islands and beaches	1965	creation	11,700-62,500	Seneca, 1980; U.S. Army, 1981
rocky shores	1981	creation	82,500-1,650,000	U.S. Army, 1981
reefs (oyster)	1978	creation	4,200	Lea, 1978

Literature Cited in Table 6

Costanza, R. Natural resource valuation and management: toward an integrated approach. Unpubl. Manuscript. CWR-LSU. Baton Rouge, LA

Gosselink, J.G., E.P. Odum, and R.M. Pope. 1974. The value of tidal marshes. CWR-LSU, Baton Rouge, LA. 30 pp.

Lea, Z. 1978. Prospectus for a ten acre oyster farm in Mississippi Sound. Sea Grant Advisory Service. Biloxi, MS.

Lewis, R.R. 1981. Economics and feasibility of mangrove restoration. In. Proc. USFWS Workshop - Coastal Ecosystems of the Southeastern United States. FWS/OBS-80/59. p. 88-94.

Lynne, G.D., P. Conroy, and F.J. Prochaska. Economic valuation of marsh areas for marine production processes. J. of Env. Econ. Manage. 8:175-186. (1981).

Raphael, C.N., and E. Jaworski. Economic value of fish, wildlife, and recreation in Michigan's coastal wetlands. CZMJ 5(3):181-194. (1979).

Seneca, E.D. 1980. Dune community creation along the Atlantic coast in J.C. Lewis and E.W. Bunce, eds. 1980. Rehabilitiation and creation of selected coastal habitats: Proceedings of a workshop. U.S. Fish and Wildlife Service, Biological Services Program, Washington, D.C. FWS/OBS-80/27. 162 pp.

Thorhaug, Anitra. Techniques for creating seagrass meadows in damaged areas along the east coast of the U.S.A. in Rehabilitation and Creation of Selected Coastal Habitats: Proceedings of a Workshop. USFWS. FWS/OBS-80/27. 1980. p. 105-116.

Tihansky, D.P., and N.F. Meade. 1976. Economic contribution of commercial fisheries in valuing U.S. estuaries. CZMJ 2(4):411-421.

U.S. Army. 1981. Personal communication, coastal engineering section, New Orleans District, Corps of Engineers.

TABLE 7

Summary of Economic Costs of Selected Spills
(Modified from OECD, in press)

Source of Spill	Santa Barbara	Zoe Colocotroni	STC 101	Amoco Cadiz	A. Gramsis
	California, 1969	Puerto Rico, 1973	Virginia, 1976	Brittany, 1978	Baltic 1979
Amount spilled (bbls)	70,000 - 140,000	38,500	6,000	1,540,000	35,000
Ecological damage (millions \$, 1979)	20-100	10	.64	34-107	72.6
Ecological damage (1979 \$/bbl. spilled)	143-1430	260	107	22-69	2074

range 22-2074 1979 $/bbl. spilled

APPENDIX 8 - B

Generic Damage Assessment of Social and Economic Impacts

Generic Damage Assessment of Potential Social and Economic Impacts

This matrix addresses issues considered to be unavoidable adverse impacts in the EIS Evaluation. While the EIS addresses a worst case scenario, the estimates here should be viewed as expected but erring somewhat on the side of overestimation. Most assessments have been summarized by region rather than planning areas. This is due to uncertainties as to the exact location of impacts. When impacts can be closely identified by planning area, the results are shown as such. Supporting textual explanations are attached. The ratings and dollar amounts represent damage in 1981 dollars expected to be caused per barrel spilled for spills of 1000 barrels or greater assuming potential impacts occur.

It is very difficult to assess the costs of most of these impacts, due to the nature of the impact and the uncertainty as to whether the impacts will occur at all or to what extent they will occur. In following ratings, low implies a relatively small likelihood of the impacts occuring, moderate implies that the impacts are likely to occur but is not expected to be severe, high indicates that a relatively severe level of impacts might occur.

Categories of Social & Economic Impact	Atlantic	Gulf	Pacific	Alaska
SOCIOECONOMIC SYSTEMS				
Economic growth from Oil and Gas development followed by some decline after Oil & Gas operations are phased down. (Boom - bust occurence)	moderate (This is an unavoidable problem for any type of economic development which relies upon a fixed amount of resources. If major development occurs, other industries may be attracted permanently, thus lessening the impacts.)	moderate	moderate	moderate
Temporary shortages of goods and services due to rapid growth from Oil & Gas development. (Infrastructure stress)	low	low	Central & Northern CA - moderate Southern CA - low	moderate
Use of resources by decisionmakers due to uncertainty of Oil & Gas development.	moderate	moderate	moderate	moderate
Use conflicts with subsistence fishing, hunting and gathering.	--	--	--	Barrow Arch, Norton Basin, - moderate to high St. George, Diapir Field, Hope Basin - moderate All other areas - low to moderate
Impacts on subsistence cultures.	--	--	--	low - moderate (enclave development expected to mitigate impacts)
Oil spill impacts on subsistence activities. $1981/barrel spilled	--	--	--	$0 - 20

.REATION

Temporary disruption of recreation areas by pipeline burials. Competition for land between recreation and OCS related activities. Degradation of the aesthetic environment conducive to recreation.	-- Moderate impacts could occur in most of the regions, except possibly upper Alaska where few recreation activities take place. Most of these impacts can be mitigated by careful site selection and by timing construction with non-peak recreation seasons.			
Use conflicts with recreation	moderate - relatively high	Eastern Gulf - moderate - high Central & Western Gulf - low - moderate	moderate - relatively high	Cook Inlet, Gulf of Alaska, Kodiak, Shumagin, N. Aleutian Shelf, St. George Basin - moderate Norton Basin, Hope Basin - low - moderate Other - low
Oil spill impacts, non-market impacts to recreationists. $1981/barrel spilled	$0 - 161	Eastern Gulf - $0 - 161 Central & Western Gulf - $0 - 127	$0 - 161	Cook Inlet, Gulf of Alaska, Kodiak, Shumagin, N. Aleutian Shelf, St. George Basin, Norton Basin, Hope Basin - $0 - 127 Other - $0 - 113
IMPACTS TO TOURISM				
Oil spill impacts $1981/barrel spilled	$0 - 22	Eastern Gulf - $0 - 22 Central & Western Gulf - $0 - 16	$0 - 22	Cook Inlet, Gulf of Alaska, Kodiak, Shumagin, N. Aleutian Shelf, St. George Basin, Norton Basin, Hope Basin - $0 - 16 Other - $0 - 11
COMMERCIAL FISHING				
Interaction with fishing industry. Damage to fishing gear. Competition for shore facilities.	North Atlantic - moderate Other - low - moderate	moderate	moderate - relatively high	St. George Basin - moderate - high N. Aleutian Basin, Kodiak - moderate Gulf of Alaska, Cook Inlet, Shumagin - low - moderate Other - low
Impacts from oil spills, loss of wages and return of capital from inability to fish, or tainting of fish. $1981/barrel spilled	$0 - 32	$0 - 32	$0 - 32	St. George, N. Aleutian Basin, Kodiak, Shumagin, Cook Inlet, Gulf of Alaska - $0 - 32 Other $0 - 11

(losses to fishermen due to oil & gas activities can be compensated, either by the financially responsible party, or by the Fishermen's Contingency Fund)

NAVIGATION & SHIPPING				
Interference to navigation.	moderate	low	moderate	Cook Inlet - moderate Other - low
HISTORICAL RESOURCES				
Damage by Oil and Gas activities and oil contamination.	low	low	low	low
LAND USE				
Impacts and conflicts from new or enlarged support bases.	low	low	Northern & Central CA - moderate Southern CA - low	moderate
OTHER USES OF THE OCS				
Military Uses	North & Mid Atlantic - low - moderate South Atlantic - moderate	Eastern Gulf - moderate Other - low	Southern CA - moderate Northern & Central CA - low	low
	(Can be mitigated by operational restrictions on both military and Oil & Gas operations.)			
Disturbance of toxic wastes dumped in the ocean.	low	low	low	low
	(Will be mitigated by avoiding known dumping sites)			
Communications Cables	low - moderate	low	low - moderate	low
AIR QUALITY				
Degradation of air quality in the vicinity of onshore transhipment and processing facilities, or from near offshore production sites. Costs of air pollution in $1981/barrel or mcf produced	low $0	low $0	Southern CA - moderate - relatively high oil production costs to air quality $.061 $1981/barrel produced gas production costs to air quality $.024 $1981/mcf produced	low $0
Degradation due to pipeline leaks and blowouts.	low	low	low	low

WATER QUALITY				
Degradation of onshore water quality from construciton, increased sewage, and operations.	low	low	Northern & Central CA - moderate Southern CA - low	moderate - high
OTHER ECONOMIC COSTS FROM OIL SPILLS $1981/barrel spilled				
Cost of oil control and cleanup	$18 - 416	$18 - 416	$18 - 416	$18 - 416
Cost of surveillance and research	$ 7 - 23	$ 7 - 23	$ 7 - 23	$ 7 - 23
Real property losses	$ 0 - 56	$ 0 - 42	$ 0 - 47	$ 0 - 24
Legal expenses	$ 1 - 4	$ 1 - 4	$ 1 - 4	$ 1 - 4
Value of oil spilled		SEE APPENDIX 8-C		

Attachment to

APPENDIX 8 - B

Generic Damage Assessment
of Social and Economic Impacts

I. Cost of Oil Control and Cleanup

This includes damages compensated by oil companies, cost of bird cleanup, water cleanup, oil containment.

4 Oil spills were analyzed. The results were as follows:

Spill	Location	barrels	$1981/ barrel	Comments
Barge STC-101	Chesapeake Bay	5,592	$150.22	31,000 birds killed damaged 27 miles shore
Santa Barbara		71,429	$415.91	oil well spill, boom in harbor 1 month.
Argo Merchant	Atlantic Ocean	178,571	$17.74	tanker spill, 540 birds killed, oil did not reach shore.
Amoco Cadiz	Brittany	1,562,000	$98.59	tanker spill, reached shore

According to Norman Mead, economist at NOAA, in general:

> Cost per barrel is generally higher for oil well spills, than for tanker spills, which are both more expensive than pipeline spills.

This is because of the relative difficulties of controlling the spill. A well can continue to spill, month after month. A tanker can only lose as much oil as is on board. Pipeline spills generally are small, or are detected and fixed before much oil has been released.

As can be noted from the above data, and was confirmed by Norman Meade there is an economy of scale for larger spills. This means that as the number of barrels spilled increases, the dollar cost of cleanup per barrel decreases. In the case of a small spills, all the cost of mobilization of eqipment is incurred, even though not many barrels of oil need to be collected or contained. This translates into a higher (relative to large spills) $/barrel cost.

As also can be noted above, the spill which did not reach shore was far less expensive. Much of the cleanup and containment costs are related to protecting or cleaning up the shoreline.

I. Cost of Oil Control and Cleanup (continued)

The type, size and location of the spill will be the primary factors in cleanup costs, with regional considerations secondary in influence. There should be little regional difference in spills which do not reach shore. For spills which reach shore, it will depend on what is hit, whether there is recreational, commercial, or residential facilities, and the extent of damage which is done. Since it is unknown exactly where a spill may hit it is difficult to calculate the value of damage. There may also be more difficulties in controlling oil spills in icy waters in Alaska, but it is not known at this time how that will be reflected in cost.

Since it is difficult to identify what the regional cost differences might be, and that location, type, and size of spill would be the primary factors, it is reasonable to use the same cost estimates for all regions.

The following matrix attempts to translate to numbers the discussion above. The split between spills less than 100,000 barrels and 100,000 barrels is based upon observation of the 4 spills, the costs of the two spills less than 100,000 barrels are significantly higher than those of the two larger spills. This is due to the economy of scale described earlier. The matrix also assumes that oil well spills are generally more expensive than tanker spills, and also that cleanup costs are generally less if the oil does not reach shore.

	Less than 100,000 Barrels	100,000 Barrels or Greater
Oil well spill		
Hits shore	High	Medium
Does not hit shore	Medium	Low
Tanker spill		
Hits shore	Medium	Low
Does not hit shore	Low	Lowest

This applied, using the four actual observations of $416, $150, $99, and $18:

	Less than 100,000 Barrels	100,000 Barrels or Greater
Oil well spill		
Hits shore	$416	$150
Does not hit shore	$150	$99
Tanker spill		
Hits shore	$150	$99
Does not hit shore	$99	$18

II. Cost of Surveillance and Research

This includes the cost of state and Federal supervision, research, monitoring, etc..

4 Oil spills were analyzed. The results were as follows:

Spill	Location	barrels	$1981/ barrel	Comments
Barge STC-101	Chesapeake Bay	5,592	$13.36	31,000 birds killed damaged 27 miles shore
Santa Barbara		71,429	$22.84	oil well spill, 21 months to control, boom in harbor 1 month.
Argo Merchant	Atlantic Ocean	178,571	$7.28	tanker spill, 540 birds killed, oil did not reach shore.
Amoco Cadiz	Brittany	1,562,000	$3.59	tanker spill, reached shore

The discussion in Section I., Cost of Oil Control and Cleanup, applies to Cost of Surveillance and Research in respect to size, type and location of the spill being the primary factors in cost. The result then, is to use the same matrix as in Section I., using the data above for the high, medium low and lowest as values for all regions. This applied, using the four actual observations of $23, $13, $7, and $4, and substituting these values as high, medium, low and lowest in the matrix in Section I.:

	Less than 100,000 Barrels	100,000 Barrels or Greater
Oil well spill		
Hits shore	$23	$13
Does not hit shore	$13	$7
Tanker spill		
Hits shore	$13	$7
Does not hit shore	$7	$4

III. Commercial Fishing Losses

This includes the loss of return on capital and wages for the fishing industry. It includes costs for inability to fish when harbors are blocked and when water is too oily to fish.

2 Oil spills were analyzed. The results were as follows:

Spill	Location	barrels	$1981/ barrel	Comments
Santa Barbara		71,429	$31.58	oil well spill, 21 months to control, boom in harbor 1 month.
Amoco Cadiz	Brittany	1,562,000	$29.58	tanker spill, reached shore

The Santa Barbara number represents the impact on 300 boat owners and crew. It includes the loss of expected return on capital for the boats and equipment (at 18% per annum), and the loss of wages for 2 months while the harbor was blocked and the fish were tainted. This is a function of duration of the spill, and commercial fishing activity where the spill hit. The impacts would have been much less had the spill not hit shore forcing the boats to stay in the harbor.

According to the EIS and information from the OCS field offices, impacts to commercial fishing could be moderate in the Pacific and the St. George Basin, the Gulf of Mexico, North Atlantic, N. Aleutian Basin and Kodiak; low to moderate in the Mid and South Atlantic, Gulf of Alaska, Cook Inlet, Shumagin; and low in the remaining planning areas of Alaska.

As the dollars per barrel spilled are not significantly different for the Santa Barbara spill of 71,429 barrels and the Amoco Cadiz of 1,562,000 barrels, one an oil well spill the other a tanker spill, no attempt will be made to differentiate between size and type of spill.

This matrix for this discussion is:

	Spill hits shore	Spill does not reach shore
Pacific, St. George Gulf of Mexico, N. Atlantic, N. Aleutian Basin Kodiak	moderate	low
Mid & South Atlantic Gulf of Alaska, Cook Inlet, Shumagin	low - moderate	low
Remainder of Alaska	low	low

III. Commercial Fishing Losses (continued)

Using the numbers and matrix from the previous page, high - moderate will be estimated at $32; moderate, and low - moderate at $30; and low at $11, ($11 is roughly one third the high, an approximation of what the low impacts might be). A lower range of zero for each category is included as there may be no cost to the commercial fishing industry at all if fishermen are not blocked into the harbor and can fish elsewhere.

IV. Real Property Losses

This attempts to estimate losses in property values due to spills. The only quantitative information for this was by Philip Sorenson for the Santa Barbara Spill.

Spill	Location	barrels	$1981/ barrel	Comments
Santa Barbara		71,429	$46.97	oil well spill, 21 months to control, boom in harbor 1 month.

Sorenson performed a fairly rigorous analysis of property values in the Santa Barbara area. He concluded that a 20% loss in value occured in the first year but that the loss was only temporary and declined gradually to zero over 5 years. He represented this cost as a decline in rental value in properties, present valued over the 5 years.

This cost would only be incurred if the oil reaches shore. To the extent that the coast line affected has similar property values, the costs would be expected to similar. The density and quality of housing would be an important function. The areas with less coastal development and population would probably have less severe impacts. The information is not available to weight the relative property values in each region.

Below is 1975 information on population density per square mile for counties in coastal regions. 1/

Atlantic	406
Pacific	187
Gulf of Mexico	114

Alaska in general, would be significantly less, due to a low population density.

Based on the above information, in comparison to the Pacific region (where Sorenson made his estimates), areas in the Gulf might incur slightly less damage, areas in the Atlantic area likely to incur significantly more damage, and Alaska significantly less. To estimate these differences, the Pacific regions will be estimated at the above value of $47, the 3 Atlantic regions at a 20% higher value, the Gulf at a 10% lower value, and Alaska at a 50% lower value.

As only one estimate of property value was available, no conclusions will be made on size or type of spill. However, it will be assumed that no property value damage is done if the oil does not reach shore.

IV. Real Property Losses (continued)

The discussion on the previous page is summarized as follows:

Spill reaches shore -	3 Atlantic regions	$56
	3 Gulf regions	$42
	2 Pacific regions	$47
	All Alaska regions	$24

Spill does not reach shore - $0

1/ Source: "Environmental Statistics 1978", Council on Environmental Quality, cosponsored by USGS & EPA, p. 23

V. Non Market Losses to Recreationists

This excludes monetary damages to recreational equipment. It is an attempt to estimate the loss in satisfaction due to the beach being closed, the water being contaminated, etc. to the persons who use the coast for recreation.

2 Oil spills were analyzed. The results were as follows:

Spill	Location	barrels	$1981/ barrel	Comments
Santa Barbara		71,429	$123.60	oil well spill, 21 months to control, boom in harbor 1 month.
Amoco Cadiz	Brittany	1,562,000	$33.16	tanker spill, reached shore

Both studies based their results on the amount of shore usage and surveys of willingness to pay. The willingness to pay surveys try to get respondents to equate satisfaction with coastal usages with paid recreation activities such as going to the movies.

The Santa Barbara study valued beach use at $2.60 per user day in 1969, or roughly 6.50 per day for user's with highest value. The following distribution of activities for the residents was collected in the survey:

Of residents surveyed for the period of one month:

- 64.9% had walked on a local beach
- 12.7% had gone swimming
- 12.7% had gone sailing or boating
- 8.1% had gone fishing in the ocean

The 6.50 per user day seems low compared to some other statistics:

A study in the southeastern United States (Horvath, 1975) discovered that recreational fishermen would have required payments averaging $55 to give up a day of fishing in 1973. 1/ ($1981 = $110 using CPI)

A 1981 study estimated user day values for California beachs as follows:

- $8.30 for beach use
- $25.00 for boating
- $49.00 for sportfishing from a boat
- $24.00 for sportfishing from manmade structures on the shoreline. 2/

1/ Howard P. Brokaw, Editor, "Wildlife and America", Council on Environmental Quality, US FWS, NOAA, US FS 1978

2/ "Inventory and Evaluation of California Coastal Recreation and Aesthetic Resources, The Granville Corp. 1981, BLM CTO-63, p. I-16.

V. Non Market Losses to Recreationists (continued)

Norman Meade, economist at NOAA who performed the analysis on the Amoco Cadiz stated that numbers from the above two surveys are not unreasonable, but that they would certainly be the upper bound from his experience.

It is very difficult to assess the proper values and how the information is to be weighted. If the Granville Study numbers were to be used, the cost would probably fall between the $8.30 and $25.00 per recreation days due to the predominance of beach use over fishing and boating in California. $8.30 is approximately 30% more than the $6.50 used in the Santa Barbara. The range for the high will be increased to 30% to account for possible undervaluing of user days, to $161 per barrel. The potential impacts upon recreation has been estimated as moderate to high in the Atlantic, Eastern Gulf, and Pacific regions according to the EIS. The impact in the Central & Western Gulf, Cook Inlet, Gulf of Alaska, Kodiak, Shumagin, North Aleutian Basin, St. George Basin, Norton Basin, and Hope Basin are expected to be low to moderate. The impact on the remainder of Alaska is expected to be low.

These impacts would be fairly insignificant if the spill does not go near shore, will assume value $0.

Based on the discussion above, a rating of moderate to high impact will be valued at the newly calculated high of $161 per barrel; low to moderate impact will be evaluated at the Santa Barbara value of $124; and low will be valued at the Amoco Cadiz value of $33. Taking into account economies of scale and type of spill (see Section I.) the recreation matrix is as follows:

	Less than 100,000 bbls	100,000 bbls or more
Oil well spill hits shore		
Atlantic	$161	$124
E. Gulf	$161	$124
C. & W. Gulf	$124	$ 33
Pacific	$161	$124
1/ Lower Alaska	$124	$ 33
2/ Upper Alaska	$ 33	$ 33
Tanker spill hits shore		
Atlantic	$124	$ 33
E. Gulf	$124	$ 33
C. & W. Gulf	$ 33	$ 33
Pacific	$124	$ 33
Alaska	$ 33	$ 33
Spill does not hit shore	$ 0	$ 0

1/ Cook Inlet, Gulf of Alaska, Kodiak, Shumagin, N. Aleutian Basin, Norton Basin, Hope Basin, St. George Basin.

2/ Remaining planning areas in Alaska.

VI. Tourism Losses

This is to measure the loss to the industries related to tourism to the country, not to the local region. See discussion below.

2 Oil spills were analyzed. The results were as follows:

Spill	Location	barrels	$1981/ barrel	Comments
Santa Barbara		71,429	negligable	oil well spill, 21 months to control, boom in harbor 1 month.
Amoco Cadiz	Brittany	1,562,000	$10.76	tanker spill, reached shore

In each study an attempt to measure net costs was made. In the Santa Barbara study it was found that although tourism losses were reported in the the spill area, areas outside the spill area reported gains. These net losses to the local area appeared to have be counterbalanced by close to identical gains, therefore making the overall cost to tourism negligable.

In the Amoco Cadiz study, Meade found a net outflow out of the country.

It is reasonable to assume tourism and recreation impacts are associated as they generally involve use of the same facilities. The same regional impact assumptions will be made for tourism as were made for recreation in section V.

Assuming there may have been some economies of scale in the Amoco Cadiz spill, will assume the value for small oil well spills is twice as much or $22, and that a "medium" value (re. the matrix in section I.) and estimate it will be 50% higher than the Amoco Cadiz or $16. Impacts will only be significant if the oil reaches shore.

VI. Tourism Losses (continued)

Based on the discussion above and the assumptions for recreation in section V., the matrix (see Section I.) for tourism is as follows:

	Less than 100,000 bbls	100,000 bbls or more
Well spill hits shore		
Atlantic	$22	$16
E. Gulf	$22	$16
C. & W. Gulf	$16	$11
Pacific	$22	$16
1/ Lower Alaska	$16	$11
2/ Upper Alaska	$11	$11
Tanker spill hits shore		
Atlantic	$16	$11
E. Gulf	$16	$11
C. & W. Gulf	$11	$11
Pacific	$16	$11
Alaska	$11	$11
Spill does not hit shore	$ 0	$ 0

1/ Cook Inlet, Gulf of Alaska, Kodiak, Shumagin, N. Aleutian Basin, Norton Basin, Hope Basin, St. George Basin.
2/ Remaining planning areas in Alaska.

VII. Legal Expenses

Legal expenses are very difficult to estimate. The only figure available in the 4 spills studied was $2/barrel for the Santa Barbara spill. These represent expenses incurred by Santa Barbara county. Conversation with Norman Meade at NOAA, indicated that no legal expenses are included in the Amoco Cadiz study because of inability to estimate, but that they are substantial.

In absence of information, and to acknolwedge there are more costs incurred than just for Santa Barbara county, an estimate of $4/bbl will be used for all regions.

Much smaller legal costs will be incurred if the oil does not reach shore, and can assume some economies of scale. It would be impossible to distinguish regional variations as it has not been possible to identify legal costs related to a single spill.

Based on the above discussion, the matrix (see Section I.) for legal expenses is:

	Less than 100,000 bbls	100,000 bbls or more
Well spill hits shore	$4/bbl	$3/bbl
Tanker spill hits shore	$3/bbl	$2
Spill does not hit shore	$1/bbl	$1/bbl

VIII. Value of Oil Lost

Estimated in Appendix 8-C.

IX. Cost to subsistence activities

In Alaska, a significant proportion of the state is partially dependent on subsistence activities. It is then, especially important to consider oil spill impacts to subsistence activities in Alaska.

There are no estimates of spill impacts on Alaskan subsistence activities as there have been no major spills in Alaska. The fishing industry is somewhat related.The Santa Barbara study estimated that 300 fishermen lost 2 months wages (and return on capital for boatowners) due to the spill due to the inability to fish.

Due to the lack of spill impact information for subsistence activities, we have assumed the impact might be similar to Santa Barbara and that 300 households might be hindered from participating in fishing and hunting subsistence activities. a set of data on subsistence activities indicate that the value of a household's subsistence hunting and fishing, plus the revenue from sales of fish and furs, is worth approximately $29,000 per year (see attachment). At this rate, the value for 300 households, for 2 months would be $1.5 million dollars. Dividing through by the number of barrels of oil in the Santa Barbara Study, a dollar amount of $20 per barrel is indicated.

This value is probably extremely high. Many communities do not have 300 households, and it is unlikely that all subsistence activities would be halted. In many cases, subsistence activities may not be affected at all. If the spill does not reach shore, it is likely that there would be few to no impacts.

Phone conversation, 12/11/81
Chuck Smythe, Alaska OCS Office
Sociocultural Specialist, SESP
8-907-276-2955

Results from Yukon Delta Study on Sociocultural Systems
by Robert Wolfe (future SESP Technical Report #72)

Study results in $1981 (study period June 1980 - May 1981)

Cost to maintain a full complement of fishing gear $3,648/year

mean household size 5.9 members
mean age of household head 47.3 years of age

mean household income (monetary income) $17,512

90.5% earned -	41.5%	commercial fishing
	5.7	commercial sale of furs
	40.7	wage employment
	2.6	retirement/social security

9.5% food stamps and other transfer payments

average household consumed 4,597 pounds dressed weight of meat products (average - 783 lbs/household member/per year)

valued at $4.62/pound - based upon purchase price of comparable meats if had to purchase

total value $21,238/household/year

6 villages surveyed

one sold average 10,447 lbs salmon/household for $7,966

one sold average 2,196 lbs herring/household for $439

Total	21,238	
	7,966	
	439	
	29,643	or $29,000

Summary Statistics from 4 oil spills in 1981 dollars/barrel

	STC-101 1/	Santa Barbara2/	Argo Merchant1/	Amoco Cadiz3/
Barrels spilled	5,592	71,429	178,571	1,562,000
Hit Shore	yes	yes	no	yes
Cleanup & Damages	150.22	415.91	17.74	98.59
Surveillance & Research	13.36	22.84	7.28	3.59
Commercial Fishing Losses	-	31.58	-	29.58
Real Property Losses	-	46.97	-	incl. above
Non-Market Losses to Recreationsists	-	123.60	-	33.16
Tourism Losses	-	negligable	-	10.76
Legal expenses	-	2.24	-	-
Value of oil lost	21.17	5.10	21.17	-
TOTAL	184.75	648.24	46.19	175.68

1/ "Total Costs Resulting From Two Major Oil Spills", U.S. Coast Guard, Dept. of Transportation, report to the Comptroller General of the U.S., GAO Rpt. #CED-77-71. Numbers were in 1976 dollars, have been inflated using a factor of 1.6 derived from the Consumer Price Index.

2/ Philip Sorensen, Walter Mead, " The Economic Cost of the Santa Barbara Oil Spill", Santa Barbara Oil Symposium, December 1970. Numbers were in 1969 dollars, have been inflated using a factor of 2.5 derived from the CPI. In June 1980, Sorenson wrote a letter to Ken Reinfeld, indicating that the cost had been increased by $2 million (1969 dollars). Since the increased costs were not broken out, they have been distributed envenly throughout the above figures and were inflated by a factor of 2.5

3/ Norman Meade, NOAA. Preliminary figures, final to be published by NOAA winter 1982. Numbers were in 1978 dollars, have been inflated using a factor of 1.4 derived from the CPI.

December 17, 1981 phone conversation
BLS, Consumer Price Index
Pat Jackman, Chief
Pat Pratico, CPI Specialist
202-272-5064

CPI- All Items, U-All Workers, U.S. City Average
(1967 = 100)

			Multiplier to Convert to 1981 dollars (1981 index/yr index) (calculated)
1960	88.7		3.1
1961	89.6		3.0
1962	90.6		3.0
1963	91.7		3.0
1964	92.9		2.9
1965	94.5		2.9
1966	97.2		2.8
1967	100.0		2.7
1968	104.2		2.6
1969	109.8		2.5
1970	116.3		2.3
1971	121.3		2.2
1972	125.3		2.2
1973	133.1		2.0
1974	147.7		1.8
1975	161.2		1.7
1976	170.5		1.6
1977	181.5		1.5
1978	195.4		1.4
1979	217.4		1.3
1980	246.8		1.1
1981	Jan.	260.5	
	Feb.	263.2	
	Mar.	265.1	
	Apr.	266.8	
	May	269.0	
	June	271.3	
	July	274.4	
	Aug.	276.5	
	Sept.	279.3	
	Oct.	279.9	
	Nov.	281.2 *	
	Dec.	282.5 *	
	81 AVG.	272.5	(calculated simple average)

*Approximation-Pat Jackman expects December to be under 283, recommended 282.5. November approximated at midway between 279.9 and 282.5.

CPI figures from Dept. Labor, BLS, calculations by C. Anderson

APPENDIX 8-C-1

Calculation of Expected
External Costs Per Barrel
of Spilled Oil for Spills
Over 1000 Barrels in Size

Appendix 8-C-1

Expected External Costs Per Barrel of Spilled Oil for Spills Over 1000 Barrels

Leasing Area	Costs are associated with spills from platforms, tankers, or pipelines as indicated for each row below	Ecological Damages	Tourism Losses	Recreation Losses	Commercial Fishing Losses	Real Property Losses	Legal Expenses	Subsistence Losses	Value of Spilled Oil	Research and Surveillance	Oil Spill Clean-up and Control	Total costs in 1981 $ per barrel of oil spilled	Percent of oil produced by platform or moved by transport mode	Expected bbl spilled per billion bbl produced x percent factor x cost per bbl spilled for spills over 1000 bbls	Total cost of spilled oil in $ millions per billion bbl produced
North Atlantic	Platform	200	2	25	8	2	2	-	33	14	200	486	100	8	
	Pipeline	600	9	60	18	8	3	-	33	16	80	827	33	13	
	Tanker	700	11	65	20	10	3	-	33	16	110	968	67	577	598
South Atlantic	Platform	400	4	30	8	6	3	-	34	15	240	740	100	12	
	Pipeline	NA	NA	NA	NA	NA	NA	-	NA	NA	NA	NA	NA	NA	
	Tanker	900	10	75	18	14	4	-	34	17	120	1192	100	1061	1073
Eastern Gulf of Mexico	Platform	700	9	60	12	25	3	-	33	18	405	1265	100	21	
	Pipeline	1000	14	100	18	35	4	-	33	20	115	1339	100	63	
	Tanker	1200	16	110	20	40	4	-	33	20	145	1588	100	1413	1497
Central Gulf of Mexico	Platform	800	6	50	20	12	2	-	35	16	390	1331	100	22	
	Pipeline	1200	10	75	28	18	2	-	35	18	110	1496	100	71	
	Tanker	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	93
Western Gulf of Mexico	Platform	700	7	50	12	15	2	-	34	15	350	1165	100	20	
	Pipeline	1100	10	85	18	28	2	-	34	17	105	1399	100	66	
	Tanker	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	86
Southern California	Platform	1200	18	135	16	40	4	-	33	22	415	1883	100	31	
	Pipeline	1300	20	150	18	43	4	-	33	23	120	1711	50	40	
	Tanker	1400	22	160	20	45	4	-	33	23	150	1857	50	826	897
Central & Northern California	Platform	1500	16	65	11	32	4	-	34	21	415	2098	100	35	
	Pipeline	1500	17	70	12	40	4	-	34	22	120	1819	25	22	
	Tanker	1600	18	70	14	43	4	-	34	22	150	1955	75	1305	1362
Gulf of Alaska	Platform	1300	-	2	10	2	3	8	27	18	350	1720	100	29	
	Pipeline	1500	1	4	14	3	3	10	27	18	110	1690	100	80	
	Tanker	1550	10	118	16	23	4	5	27	20	135	1908	100	1698	1807
Kodiak	Platform	1000	-	2	20	2	3	8	27	20	375	1457	100	24	
	Pipeline	1300	1	4	26	3	3	12	27	20	110	1506	100	71	
	Tanker	1450	10	118	23	23	4	6	27	21	140	1822	100	1622	1717
Shumagin	Platform	1000	1	2	12	2	2	13	26	16	350	1424	100	24	
	Pipeline	1300	1	4	12	3	2	15	26	16	110	1489	100	71	
	Tanker	1450	10	118	16	23	3	8	26	19	135	1808	100	1609	1704
Cook Inlet	Platform	1600	2	9	14	5	3	4	27	20	415	2099	100	35	
	Pipeline	1700	2	9	14	5	3	4	27	20	120	1904	100	90	
	Tanker	1600	11	120	16	24	4	2	27	21	150	1975	100	1758	1883
North Aleutian Basin	Platform	1200	-	-	12	1	2	10	27	18	400	1670	100	28	
	Pipeline	1400	-	1	14	2	2	14	27	18	115	1593	100	75	
	Tanker	1500	10	116	16	23	3	7	27	20	145	1867	100	1662	1765
St. George Basin	Platform	1300	-	1	20	-	3	15	27	16	300	1682	100	28	
	Pipeline	1600	-	1	22	-	3	17	27	16	100	1786	100	85	
	Tanker	1600	10	116	20	22	4	9	27	19	125	1952	100	1737	1850
St. Matthew Hall	Platform	400	-	-	2	1	2	18	27	12	350	812	100	14	
	Pipeline	1100	-	1	3	2	2	24	27	12	115	1281	100	61	
	Tanker	1350	10	115	10	23	3	12	27	17	135	1702	100	1515	1590
Navarin Basin	Platform	100	-	-	2	-	1	1	24	10	250	388	100	6	
	Pipeline	800	-	1	3	-	2	3	24	10	85	928	100	44	
	Tanker	1200	10	115	11	22	3	2	24	16	105	1508	100	1342	1392
Norton Basin	Platform	1600	-	-	3	1	1	16	24	14	400	2059	100	34	
	Pipeline	1800	-	1	4	2	2	20	24	14	120	1987	100	94	
	Tanker	1700	10	115	12	23	3	10	24	18	150	2065	100	1838	1966
Hope Basin	Platform	900	-	-	2	1	1	18	21	18	400	1361	100	23	
	Pipeline	1100	-	1	3	2	2	24	21	18	120	1291	100	61	
	Tanker	1350	10	115	11	23	3	12	21	20	150	1715	100	1527	1611
Barrow Arch	Platform	800	-	-	3	1	1	9	26	18	400	1258	100	21	
	Pipeline	900	-	1	4	2	2	14	26	18	120	1087	100	51	
	Tanker	1250	10	115	10	23	3	7	26	20	150	1614	100	1437	1509
Diapir Field	Platform	1500	-	-	3	1	1	10	28	18	400	1961	100	33	
	Pipeline	1500	-	1	4	2	2	12	28	18	120	1685	100	80	
	Tanker	1550	10	115	11	23	3	6	28	20	150	1916	100	1705	1818
Old North Atlantic	Platform	100	3	20	10	3	2	-	33	16	200	387	100	6	
	Pipeline	400	7	50	20	8	3	-	33	16	88	625	33	10	
	Tanker	600	8	60	30	9	3	-	33	19	100	872	67	520	536
Old Mid Atlantic	Platform	300	5	40	12	5	3	-	33	16	200	614	100	10	
	Pipeline	600	9	60	15	9	4	-	33	16	88	834	33	13	
	Tanker	700	10	70	20	10	4	-	33	19	110	976	67	582	605

NA = Not Applicable

Description of Appendix 8-C-1
Expected Unit External Costs Related to Oil Spills Over 1000 Barrels in Size

Expected external costs were estimated for the potential impacts from oil spills over 1000 barrels for which reasonably acceptable economic loss data could be obtained and used in this analysis. External costs not addressed here are covered by the FEIS and SEIS.

Leasing areas in the table on the preceding page are listed on the left side and external costs form the column headings across the top. Entries are expressed in dollars per barrel of oil spilled for the costs caused by expected oil spills of 1000 barrels (bbl) or greater. All entries were reviewed, discussed, and adjusted as appropriate by Interior Department experts on the impacts of OCS oil and gas, including representatives of the Bureau of Land Management, the Fish and Wildlife Service, and the staff of the Assistant Secretary for Policy, Budget and Administration.

EXPLANATION OF INDIVIDUAL COSTS OF OII SPILLS

Ecological Damages

The first step in estimating ecological damages was to arrive at a generic damage estimate range. Table 7 of Appendix 8-A indicates a range of $22-2079/bbl as the ecological damage from five oil spills. Using the common practice of throwing out the high and low value, the range is $69 - 1430/bbl expressed in 1979 dollars, or converted into 1981 dollars the range is $90-1860/bbl. These numbers were rounded to a range of $100-1900/bbl.

This range is only a very rough estimate of the range of possible ecological damages. The data in the literature for the five oil spills was collected in a non-uniform manner from spill to spill. Also, the spills occurred in various geographic locations; affected various resources of varying values; occurred at various distances from the ecological resources for which damage estimates were made; occurred during various weather conditions; were of various chemical compositions; and so forth. Using such various estimates as the range of ecological damages which might be experienced nationwide from OCS oil and gas development is not standard scientific practice, but is used for lack of a more precise method of estimating the economic value of ecological damages.

The second step in estimating ecological damages was to specify what factors may be most important in influencing the degree of damages which could occur per barrel of oil spilled from each of the three possible sources of spills (platforms, pipelines, and tankers). The following factors were deemed most important: geographic location of the source of the spill, the geographic location of economically valuable ecological resources, the proximity of the source of the spill to the resources, the relative economic value of the resources, relative environmental sensitivity and quantity of the ecological resources which may be affected by spills of 1000 barrels or greater (see Appendix 10), the relative marine productivity of each leasing area (see Appendix 10), the likelihood that a spill may reach the economically valuable resources, and the fraction of oil spilled which would likely reach the economically valuable resources.

The third step was to estimate the amount of potential damage per barrel spilled for spills of 1000 barrels or greater for platforms, pipelines and tankers for each leasing area from the range of $100 to $1900/bbl. This was accomplished by making the best professional judgement based on the FEIS, SEIS, Appendices 8-A and 10, and the advice of ecological experts within the Department of Interior. These estimates appear as the first column of numbers in the table at the beginning of this Appendix 8-C-1. Estimates for platforms presume that potential spills occur at the platform site (estimates for spills of 1000 barrels or greater from exploration activities are presumed to be negligible since no such spills have been experienced from OCS oil and gas exploration activities). Estimates for pipelines assume that spills occur at the platform, along the way to shore and at the landfall. Estimates for tankers assume that about two-fifths of the spills occur in the general vicinity of the loading site, one fifth occurs at sea en route and two fifths occur in the general vicinity of the unloading site. Since all Alaskan oil is hypothesized in this analysis to be tankered to Central and Northern or Southern California in about equal proportion (a hypothesis based on discussions with Department of Energy experts), half the estimated potential ecological damages from tankering Alaskan OCS oil were calculated based on spills occuring in the Alaskan area of origin and one quarter occuring in the Central and Northern California area and one quarter occuring in the Southern California area.

With respect to tanker transport of Alaskan oil it should be noted here that while a very small fraction of potential tanker spill damages might be experience by some of the Alaskan areas south of the area of origin and by the States of Washington and Oregon, the ecological damages for Washington and Oregon would be expected to be similar to those of Central and Northern California and for the most part, the damages of the southward Alaskan areas are more or less similar to the Alaskan area of origin, thus the above Alaskan allocation assumption seems appropriate for the sake of simplicity.

Tourism Losses

Pages 256-271 of the FEIS, relevant sections of the Final Supplemental EIS, Appendix 10 and Section VI of Appendix 8-B were used as the basis for estimating tourism losses estimating per barrel of oil spilled for spills over 1,000 barrels. In a manner similar to that described above for Ecological Damages, but using Appendix 8-B for potential generic damage, consideration was given to proximity of the OCS areas to tourist facilities and uses, the relative numbers of tourist-days in the coastal area and the availability of alternative tourist activities and facilities. St. George Basin and those areas northward were not assigned a value for tourism losses occurring within the area because they were judged to be much lower than the other leasing areas on a relative basis. However, the same allocation treatment was given to tourism losses from tanker spills as was given to ecological losses as indicated above. Thus, St. George Basin and those areas northward were assigned a value for tourism losses for half the estimated potential spills associated with transport of the area's oil resources. This method of allocation also applies to the other costs of oil spills shown below. There is a strong correlation between tourism losses and the recreation losses which follow.

Recreation Losses

Pages 257-271 of the FEIS, relevant sections of the Final Supplemental EIS, Appendix 10 and Section V of Appendix 8-B were used to estimate non-market losses to recreationists. Consideration was given to the proximity of the OCS area to recreational uses and facilities, the relative number of recreation-days in the coastal area and alternative recreation opportunities. The Alaskan areas show relatively little in recreation losses compared to the lower 48 leasing areas. There is a strong correlation between recreation losses and the tourism losses described in the preceding section.

Commercial Fishing Losses

Pages 206-220 of the FEIS, relevant sections of the Final Supplemental EIS, Appendix 10 and Section III of Appendix 8-B were used to estimate commercial fishing losses, which includes loss of return on capital and wages for the fishing industry and costs for the inability to fish when harbors are blocked and when the water is too oily to fish, etc. Loss of fish and shellfish were omitted since they are included under ecological damages above. Consideration was given to the proximity of the leasing area to the fishing grounds and to the fishing ports and the relative catch expected for each area and its value.

Real Property Losses

Section IV of Appendix 8-B was used as the basis for real property losses. Consideration was given to the proximity of the leasing area to shore, the relative value of coastal property and population densities.

Legal Expenses

Section VII of Appendix 8-B explains the basis for legal expenses. However, the legal expenditures of Section VII were adjusted based on expected value of damages and on consultation with legal experts of the Department of Interior.

Subsistence

Pages 285-300 of the FEIS, relevant sections of the Final Supplemental EIS, Section IX of Appendix 8-B, Appendix 10 and the Interior Department publication, Alaskan Regional Profiles were used to judge the impact on subsistence. A key determination is the number of natives dependent on subsistence and the degree of their dependence. Estimating economic losses of subsistence is especially difficult due to lack of data on OCS oil spill related damages and the fact that subsistence is based on different value system than the dollar and thus conversion to dollars is controversial. Furthermore, the estimating method for generic subsistence losses is somewhat unique (see Section IX of Appendix B), but was judged the best method available. Even though these estimates are likely overstated, to help further assure erring on the high side of subsistence loss estimates, the top value given in Section IB of Appendix B was raised by 20%. Subsistence outside Alaska was judged to be negligible compared to Alaskan area and thus was not estimated.

Value of Spilled Oil

The value of expected spilled oil for each area is $35/bbl less the estimated cost of transportation which would have been needed to complete the transit of crude oil to market.

Research and Surveillance

Section II of Appendix 8-B explains these costs. Variations are not expected to be great region to region since any large oil spill on the OCS will likely be studied thoroughly wherever it may occur.

Oil Spill Control and Clean-up Costs

Section I of Appendix 8-B explains oil spill control and clean-up costs. Oil spill control and clean-up costs per barrel are expected to be second only to ecological costs. As above, different estimates are given for platform, pipeline and tanker spills. Variations from region to region are based primarily on proximity of the leasing area to shore and on severity of weather conditions. Clean-up costs per barrel of oil spilled are expected to be much higher for spills that hit shore, than those that don't. In general, oil spill control costs per barrel are expected to be highest for platform spills, less for tanker spills and even less for pipeline spills on a per barrel basis.

CALCULATION OF TOTAL COST OF SPILLED OIL FOR SPILLS GREATER THAN 1,000 BARRELS

The right hand column, entitled "total cost of spilled oil in $\$10^{6}$* per 10^{9}* bbl produced", is derived as shown in the following example for the North Atlantic:

Step 1 Sum the first ten columns of estimated dollar costs for spills of 1000 barrels or more from platforms:

$$200 + 2 + 25 + 8 + 2 + 2 + 0 + 33 + 14 + 200 = \$486$$

Step 2 Repeat Step 1 for spills from Pipelines and Tankers - the respective sums are \$827 and \$968.

Step 3 Multiply the results of Steps 1 and 2 by the expected number of spills (greater than 1000 bbls) per 10^{9} bbl of production by the historic mean number of bbls spilled for spills over 1000 bbls for platform, tankers and pipelines.**

$$\text{Cost per barrel Platform spills} = \frac{\$486}{\text{bbls spilled}} \times \frac{0.79 \text{ spills}}{10^{9} \text{ bbl produced}} \times \frac{21{,}000 \text{ bbl spilled}}{\text{spill}}$$

$$= \$8 \times 10^{6} \text{ per } 10^{9} \text{ bbl produced}$$

$$\text{Cost per barrel pipeline spills} = \frac{\$827}{\text{bbl spilled}} \times \frac{1.82 \text{ spills}}{10^{9} \text{ bbl transported}} \times \frac{26{,}000 \text{ bbl spilled}}{\text{spill}}$$

$$= \$39 \times 10^{6} \text{ per } 10^{9} \text{ bbl transported by pipeline}$$

---

* 10^{6} = millions; 10^{9} = billions

** USGS estimates that the mean size of recorded offshore oil spills over 1000 barrels for the nine United States OCS platform spills and the eight U.S. OCS pipeline spills since 1964 is 21,000 and 26,000 barrels respectively. Oil Spill Intelligence Report indicates that in 1978 and 1979, 22 tanker spills offshore worldwide had a mean of 230,000 barrels. USGS data estimates platform, pipeline and tanker spill rates to be: .79, 1.82, and 3.87 spills of 1000 barrels or greater per billion barrels of production of OCS oil.

Cost per barrel
Tanker spills $= \frac{\$968}{\text{bbl spilled}} \times \frac{3.87\ \text{spills}}{10^{9}\ \text{bbl transported}} \times \frac{230{,}000\ \text{bbl spilled}}{\text{spill}}$

$= \$862 \times 10^{6}$ per 10^{9} bbl produced

Step 4 Multiply the results of Step 3 by the appropriate percentage of oil produced by platform (always 100%) and by mode of transport* to calculate subtotal costs of spilled oil for spills of 1000 barrels or greater in $ millions per billion barrels produced ($\$10^{6}$ per 10^{9} bbl):

$\$8 \times 10^{6}$ per 10^{9} bbl produced times

Platforms 100% produced from platform

$= \$8 \times 10^{6}$ per 10^{9} bbl produced

$\$39 \times 10^{6}$ per 10^{9} bbl transported by pipeline times

Pipelines 33 1/3% of production transported by pipeline

$= \$13 \times 10^{6}$ per 10^{6} bbl produced

$\$862 \times 10^{6}$ per 10^{9} bbl transported by tanker times

Tankers 67 2/3% of production transported by tanker

$= \$577 \times 10^{6}$ per 10^{9} bbl produced

---

* Note in the table at the beginning of this Section of Appendix 8 that all production from all areas except the North Atlantic, Central and Western Gulf of Mexico, and the California areas is presumed to be shipped first by pipeline and then by tanker.

Note that for Alaskan areas, one half the potential tanker spill damages are estimated to occur in the Alaskan leasing area of origin, one quarter in Central and Northern California and one quarter in Southern California as indicated under the Explanation of Ecological Damages, above. Thus, for example, the calculation for estimated potential ecological damages for spills of 1000 barrels or greater from tankers for the oil resources of Kodiak is as follows:

While \$1400 = potential damages per bbl to Kodiak OCS and coastal areas, this number is not shown explicitly on the table of this Appendix. \$1400 and \$1600 = potential damages per bbl to Southern California and Central, and Northern California OCS and coastal areas, respecitvely. Thus:

$$(1400) \times (.5) + (1400) \times (.25) + (1600) \times (.25) = \$1450$$

Step 5 Add the three results of Step 4 to get total estimated cost of spilled oil for spills over 1000 bbls per 10^9 bbl of production:

$$\$8 + \$13 + \$577 = \$598 \times 10^6 \text{ per } 10^9 \text{ bbl of production}$$

APPENDIX 8-C-2

Calculation of Expected External Costs Per
Unit of Production and Adjustment
to Present Value

Appendix 8-C-2

Expected External Costs Per Barrel Associated With Exploration And Production And Summary of All Measureable Expected External Costs Adjusted to Present value

Proposed Leasing Area	Present Value of Air Quality Losses in $ millions per billion BOE of production (in July 1981 dollars)	Present value (July 1981) of onshore habitat losses from onshore support facilities in $ millions per billion BOE assuming all BOE leased in 1982	Total oil spill costs from Appendix 8-C-1	Multiply oil spills costs by these present value (July 1981) factors to adjust for spills occurring 3 years after first production	Present value of oil spill costs ($ millions per billion bbl of production) adjusted for July 1981
N. Atl.	7	4.7	598	.368	220
S. Atl.	3	59.6	1073	.500	537
E. GOM	3	66.0	1497	.540	808
C. GOM	7	7.1	93	.681	63
W. GOM	9	1.5	86	.681	59
S. Cal.	19	0.6	897	.500	449
C & N Cal.	14	6.1	1362	.583	794
GOA	-	42.0	1807	.500	904
Kodiak	-	42.0	1717	.500	859
Shumagin	-	42.0	1704	.500	852
Cook Inlet	-	42.0	1883	.500	942
N. Aleut.	-	41.1	1765	.500	883
St. Geo.	-	41.1	1850	.463	857
St. Matt.	-	41.1	1590	.463	736
Navarin	-	40.0	1392	.463	644
Norton	1	36.3	1966	.429	843
Hope	-	36.3	1611	.463	746
Barrow	-	108.6	1509	.540	815
Diapir	-	53.3	1818	.500	909
Old N. Atl.	6	4.7	536	.500	268
Old M. Atl.	7	4.8	605	.368	223

Description of Appendix 8-C-2

Expected unit costs associated with exploration and production activities (measurable non-oil spill related costs) include air quality losses and habitat losses from onshore support facilities.

Air quality losses

Air quality losses are based on the 1979 CTARP Energy Facility Siting Study prepared for NOAA, Appendix 8-B, pp. 272-279 of the FEIS, and relevant pages of the Final Supplemental EIS. Air quality loss estimates were made first for the Southern California area since data was available. Then, using the air quality rankings in the SEIS, climatic conditions of the adjacent onshore areas, relative estimates of the population of the adjacent onshore areas potentially affected by air pollution from OCS oil and gas development related activities, present levels of air pollution, and relative amounts of oil and gas estimated for the leasing areas, estimates were made for the leasing areas based on an estimate of potential economic losses in \$ per billion BOE relative to Southern California. Many of the Alaskan areas rated so low that their estimates are negligible.

Air quality losses for Southern California were assigned a present value of \$19 million per billion BOE of production. The value for Southern California is calculated as follows:

From the 1979 CTARP study, oil related costs = \$.061 per bbl of oil produced and \$.024 per MCF of gas produced. Hence, $\$.061/\text{bbl} \times 1.79 \times 10^{9}$ bbl of oil expected to be produced = $\$109 \times 10^{6}$; $\$.024/\text{MCF} \times 10^{9} = \$24 \times 10^{6}/\text{TCF}$, $\$24 \times 10^{6}/\text{TCF} \times 3.07$ TCF expected to be produced divided by 5.62 (to convert TCF to BOE $\times 10^{9}$) = $\$13 \times 10^{6}$; $\$109 \times 10^{6}$ plus $\$13 \times 10^{6} = \$122 \times 10^{6}$; $\$122 \times 10^{6}$ divided by 2.34 BOE $\times 10^{9}$ expected to be produced equals $\$52.1 \times 10^{6}$ per BOE $\times 10^{9}$ expected cost.

The present value of air quality losses is derived by dividing the loss per billion BOE by 32 years (duration of exploration, development and production phases) and taking the present value of the result for each year. For Southern California:

$\$52.1 \times 10^{6}$ per BOE $\times 10^{9}$ divided by 32 = $\$1.63 \times 10^{6}$ per BOE $\times 10^{9}$; the sum of the present values = of $\$1.63 \times 10^{6}$ per BOE $\times 10^{9}$ each year for 32 years = 11.74 (present value factor) X 1.63 = $\$19 \times 10^{6}$ per BOE $\times 10^{9}$.

Habitat losses from onshore support facilities

Habitat losses from onshore support facilities are based on Table 6 of Appendix 8-A, pp. 197-201, 221-236 and 323 of the FEIS, relevant sections of the Final Supplemental EIS, Appendix 10, Estimate for New England (NERBC), and expert advice from the Fish and Wildlife Service, the U. S. Geological Survey and the Bureau of Land Management. Losses are assumed to occur both from the initial destruction of the habitat (e.g. wetlands) and from subsequent degeneration of adjacent habitat attributable to the initial action and subsequent operational activities. Habitat losses are expected to be greatest in areas which do not have existing onshore support facilities, in which wetlands predominate, and in which environmental sensitivity is greatest. Since little data is available on habitat losses attributable specifically to onshore support facilities for OCS oil and gas development, and since mitigation measures which may be evoked to minimize such habitat losses are entirely within the authority of the coastal states, a number of estimates need to be made: the required number of acres of new onshore support facilities for OCS exploration, development and production activities; the percent of onshore support acreage which is likely to be wetlands or other sensitive habitat; the rate at which adjacent habitat will be lost once the initial acres are filled; the number of years that additional acres will be lost and the changes in the rate of loss over time. Based on these estimates, the present value of each year's loss of wetlands was computed for each leasing area using $7380 per acre per annum which is the 1981 dollar equivalent to the total life support basis of $4100 per acre derived by Gosselink, et al in 1974 (see Table 6, Appendix 8-A). The estimates and analytical steps used to compute the present value of habitat losses are shown in the Attachment to this Appendix.

A note of importance - these estimates are made based on an assumption of little or no regulation of wetland use by coastal states, who have full authority over their onshore areas. If states, through their coastal zone management programs or other regulations, require protective or mitigative measures, the external costs related to onshore habitat losses will be proportionally reduced.

Present value for oil spill losses

To simplify the analysis, all oil spills were assumed to occur 3 years after the start of production. Based on this assumption, a present value factor is used to calculate present value for each leasing area. For example, the start of production in Cook Inlet is estimated to be 1988 (one year after the first development/production well) if all the resources of Cook Inlet were leased in 1982. If all expected oil spills occured 3 years later in 1991, the value of the spill would have to be discounted at 8% for 9 years which dictates a present value factor and hence a reduction of .500. This assumption errs on the high side for oil spill costs since production is expected to continue for more than 40 years in Cook Inlet.

Attachment to Appendix 8-C-2

Logic steps used to calculate present value of lost wetlands per BOE of expected Production of Hydrocarbons

Step

(1) Enter values for:

DA	\$ per acre of wetlands lost/yr.
AE	acreage needed for act. during exploration
AP	acreage needed for act. during development
a,b	starting year for exploration to year before before first platform is installed
c,d	year first platform is installed to year last platform is installed
e,f	starting and ending years for declining production
R	rate of increase of lost acreage
DR	discount rate to calculate present value (8% is used)

(Description of other terms:

A	accumulator for sum of present value
NA	accumulator for acreage
i	year of current calculation
j,X,Y and PV	temporary storage slots

(2) $A = 0$

(3) $i = a$

(4) $X = AE$

(5) if $i = c$, $X = NA + AP$

(6) if $d < i < f + 1$, $NA = X + R \cdot \left(\frac{i - e + i}{f - e + i}\right) \cdot X$, go to step (9)

(7) if i = f + i, go to Step (16)

(8) NA = X + R X

(9) X = NA

(10) Y = NA DA

(11) PV = Present value of Y for "i" th year @ discount rate DR

(12) A = A + PV

(13) j = i

(14) i = j + 1

(15) Go to Step (5)

(16) Display NA and A

Data for Wetlands

Calculations

Run #	Leasing area	DR	DA	AC	AP	a	b	c	d	e	f	R
1	Old N. Atl. New N. Atl.	.08	7380	10	60	0	7	8	21	22	38	.02
2	Old M. Atl.	.08	7380	10	60	0	6	7	16	17	34	.02
3	73% of S. Atl.	.08	7380	60	300	0	3	4	15	16	34	.10
4	16% of S. Atl.	.08	7380	20	120	0	3	4	15	16	34	.04
5	12% of S. Atl.	.08	7380	10	60	0	3	4	15	16	34	.02
6	E. GOM	.08	7380	50	300	0	2	3	18	19	26	.10
7	C. GOM	.08	7380	5	30	0	1	2	19	20	25	.10
8	W. GOM	.08	7380	2	12	0	1	2	19	20	26	.04
9	S. Cal.	.08	7380	1	6	0	3	4	16	17	32	.02
10	C & N Cal.	.08	7380	10	60	0	2	3	13	14	30	.02
11	GOA Kodiak Shumagin Cook Inlet	.08	7380	67	400	0	3	4	13	14	42	.02
12	N. Aleut. St. Geo. St. Matt.	.08	7380	67	400	0	3	4	8	9	41	.02
13	Navarin	.08	7380	67	400	0	4	5	17	18	44	.02
14	Norton Hope	.08	7380	67	400	0	5	6	11	12	42	.02
15	Barrow	.08	7380	110	660	0	2	3	12	13	35	.06
16	Diapir	.08	7380	33	200	0	3	4	16	17	36	.10

The rationale for selection of acreage data for wetlands calculations

Table 2.3 of Estimates for New England, prepared by the New England River Basin Commission (NERBC) estimates onshore support acreage requirements in New England of 1400 acres for a high find scenarios (2.4 billion bbl oil and 12.5 TCF gas = 4.8 billion BOE). It should be noted that 1000 acres for a refinery was subtracted from NERBC's estimate of 2400 acres since in this analysis, acreage for refineries is not included as an OCS related activity. Assuming 20% of this acreage is wetlands as estimated by the Fish and Wildlife Service (FWS), 280 acres, or approximately 300 acres, would be wetlands. Thus, approximately 60 acres of wetlands would be expected to be destroyed for every billion BOE of production (300/4.8 = 58.3 or approximately 60 acres). Using this number as a base, the following assumptions were made in consultation with FWS staff. 1) Potential onshore support areas in La., Miss., Ala., Fla., SC, Ga., and the north slope of Alaska are presumed to be nearly 100% wetlands; 2) in N. C. and Tex. onshore support acreage is presumed to be 40% wetlands and everywhere else it is presumed to be 20% wetlands. Thus, where new onshore support facilities are expected to be needed, 300, 120 and 60 acres of wetlands per billion BOE, respectively, are expected to be destroyed in such areas. Of this acreage, 1/6, or 50, 20 and 10 acres respectively, are expected to be needed initially for exploration.

Since FWS information indicates that destruction of additional wetlands can result from an ecological reaction to the initial destruction and ongoing operational activities, these acreages were estimated, based on consultation with FWS, to increase at the rate of 10%, 4% and 2% for each year, respectively, during exploration and up to the end of platform installation and then drop off to zero by the end of production activity. Exceptions to the above assumptions about initial acreage are made wherever the Final Supplemental to the EIS indicates that little or no new acreage for onshore support facilities is required. In such cases, the 10, 4 or 2 percentage increase is used as a base for outyear increases. Such exceptions pertain to Central and Western Gulf of Mexico and Southern California.

Another exception was made for Alaska were data from the Arctic Summary Report (USGS Open File Report 81-621) was used along with advice from the USGS. That is, existing onshore support operations on the North Slope are contained in approximately a 250 sq. mi area of which approximately 15% actually contains support facilities (250 sq mi X .15 X 640 acres/sq mi = 24,000 acres). This acreage has supported 12.5 billion BOE production or approximately 2000 acres per billion BOE (24,000/ 12.5 = 1920 or about 2000). For all onshore support areas of Alaska except Barrow Arch and Diapir Field, FWS projects that 20% would be wetlands or 400 acres per billion BOE (2000 X .20). For Diapir Field, existing facilities would be used for essentially all acreage demands, so only the rate of increase (2000 acres X 10% = 200 acres) is used as a base. For Barrow Arch, half the area expected to be used for onshore facilities is estimated to be all wetlands. Also, half the support facilities are expected to exist. Therefore, 1000 new acres are expected to be required (2000 acres/BOE X 10 X .5) and of these 500 plus 100 (500 X 20%) = 600 are expected to be wetlands. Thus the total wetland acreage is 600 + 60 (1000 existing acreage X 6% = 60) = 660 acres.

APPENDIX 8-D-O

Calculation of Estimated Total Expected External Costs (in 1982 Dollars) Associated with Development of All the Resources in Each Planning Area

Appendix 8-D-O

Total Expected External Costs in 1982 Dollars Associated with Leasing All Resources in Each Planning Area in July 1982

Proposed Leasing areas	Present Value (July 1982) of oil spilled $ millions per billion bbl produced (for all resources leased in 1982)	Present Value (July 1982) of air quality losses in $ millions per billion BOE produced (for all resources leased in 1982)	Present Value (July 1982) of onshore habitat losses from OCS support activity in $ millions per billion BOE (for all resources leased in 1982)	Billion bbl oil production	Billion BOE production	Gross Total Expected External costs in $ billions (Column 1 X Col. 4 + Col. 5 X (Col. 2 + Col. 3)	$ value of foregone damages from backing out foreign crude oil imports via tankers	Net Total Expected External Costs ($ billions)	Net Total Expected External Cost of Estimated Recoverable Resources in Dollars per BOE
Column Designation	1	2	3	4	5	6	7	8	9
N. Atl	238	8	5.1	4.00	6.98	1.043	.861	.182	.03
S. Atl	580	3	64.4	0.96	1.60	.665	.281	.384	.24
E. GOM	873	3	71.3	1.07	1.31	1.031	.338	.693	.53
C. GOM	68	8	7.7	3.24	9.45	.369	1.291	-.922	.10
W. GOM	64	5	1.6	1.47	6.14	.135	.586	-.451	.07
S. Cal	485	21	0.6	1.79	2.34	.919	.524	.395	.17
C&N Cal	858	15	6.6	0.85	1.06	.752	.290	.462	.44
GOA	976	-	45.4	0.35	0.70	.373	.102	.271	.39
Kodiak	928	-	45.4	0.34	0.69	.347	.099	.248	.36
Shumagin	920	-	45.4	0.08	0.18	.082	.023	.059	.33
Cook In.	1017	-	45.4	0.09	0.21	.101	.026	.075	.36
N. Aleut.	954	-	44.4	0.19	0.35	.197	.056	.141	.40
St. Geo.	926	-	44.4	0.45	0.90	.457	.122	.335	.37
St. Matt.	795	-	44.4	0.00	0.00	-	-	-	-
Navarin	696	-	43.2	0.87	1.86	.686	.236	.450	.24
Norton	910	1	39.2	0.16	0.38	.161	.040	.121	.32
Hope	806	-	39.2	0.02	0.07	.019	.005	.014	.20
Barrow	880	-	117.3	0.71	1.28	.775	.224	.551	.43
Diapir	982	-	57.6	2.77	5.39	3.031	.810	2.221	.41
Old N. Atl	289	6	5.1	1.32	2.29	.407	.386	.021	.01
Old M. Atl.	241	8	5.2	2.68	4.68	.708	.577	.131	.03

Description of Appendix 8-D-O

The first three columns of data (designated as 1, 2 and 3) are taken from Appendix 8-C-2 and adjusted (increased by 8%) to reflect increases in costs up to mid-1982. Columns 1, 2 and 3 represent the expected external costs in $ millions per billion bbl or in $ millions per billion barrels of oil equivalent (BOE) (the former for oil spill related costs and the later for air quality and habitat losses). These columns are then multiplied by the expected amount of hydrocarbons in billion bbl or in billion BOE (columns 4 and 5 respectively) projected by the U. S. Geological Survey (USGS) for each leasing area. The result appears in column 6 - "Gross Total Expected External Costs in $ billions." The gross total expected external costs are then reduced by the dollar value of avoided damages from backing out foreign crude oil imports via tankers (see column 7). The result is the net total of expected external costs in $ billions if all the resources of the area were leased in 1982 and then developed. (See column 8). The value of avoided damages from foreign tankers is calculated as follows:

From Table 9 of Department of Energy, Energy Information Administration Monthly Petroleum Statement dated November 1981, it was estimated that 26, 20, 15, 33, 3 and 3% of imported foreign crude oil arrives in the U.S. via ports in the Mid-Atlantic, Great Lakes, Central Gulf of Mexico, Western Gulf of Mexico, Southern California, and Central and Northern California, respectively. Crude oil does enter via other ports, however, the relative amount is quite small.

The expected damage in $ million per billion bbl from foreign tankers is calculated for the areas in which foreign crude is expected to arrive as in the following example for the Old Mid-Atlantic - From the table of Appendix 8-C-1, the total costs in 1981 $ per bbl of spilled oil for spills of 1000 bbl or greater is $976. To calculate $ million per billion transported, multiply $976 times 3.87 spills per billion bbl transported times 230,000 bbl spilled per spill of 1000 bbl or greater (see rationale in discussion in Appendix 8-C-1). The result = $869 million of damage from tanker spills per billion bbl transported by tanker. Making similar calculations for each of the above areas, and then multiplying by the above percentages of foreign crude being imported into each area, the nationwide average of damage in $ million per billion BOE for foreign tanker spills is calculated as follows:

Mid. Atl.	$869 million per billion bbl X .26 =	226
Great Lakes	1653 million per billion bbl X .20 =	331
Central GOM	1467 million per billion bbl X .15 =	220
Western GOM	1440 million per billion bbl X .33 =	425
S. Calif.	1653 million per billion bbl X .03 =	50
C & N Calif.	1740 million per billion bbl X .03 =	52
		1354

Then multiplying this by 1.08 to adjust for estimated present value in July 1982, the average of damage from tankers transporting foreign crude oil to the U.S. is $1462 million per billion bbl. It is important to realize that this damage base of $1462 was calculated by making rough estimates of damage from spills at the point of loading from a platform (relatively low damage per barrel spilled) in transit (only slightly higher damage per barrel spilled) and in the vicinity of unloading (high damage). These three estimates were then roughly weighted by factors of 2, 1 and 2 respectively, representing the estimated likelihood of spills occurrence of 40%, 20% and 40% respectively.

Next in the calculation, we assume that expected damage from spills from foreign tankers are borne by the U.S. only if the spill occurs in the vicinity of the unloading point (i.e. in our coastal waters). We thus multiplied the $1462 million per billion barrels transported by 40%, assuming that 60% of damage from foreign tanker spills is not borne by the U. S. The result is (.40) (1462) = 585. This approach under estimates the damage avoided because damage in the vicinity of the unloading point is expected to be larger than 40% of the $1462 estimate as explained below.

The amount $585 million per billion bbl is then multiplied by the present value factor of the table in Appendix 8-C-2 and the expected production in billion bbl, (Column 4 of the table in this Appendix) and the result is shown as Column 7. For example, for the North Atlantic the calculation is as follows:

$$(\$585 \text{ X } 10^{6} \text{ per } 10^{9} \text{ bbl}) \text{ X } (.368) \text{ X } (4.00 \text{ bbl X } 10^{9}) = .\$861 \text{ billion}$$

Column 9, the total expected external cost per BOE of expected recoverable resources in each area, is calculated by dividing the entries in Column 8 by the estimated billions of BOE of production in Column 5. For example, for the North Atlantic, the calculation is as follows:

$$\$.155 \text{ X } 10^{9} / 6.98 \text{ BOE X } 10^{9} = \$.02 \text{ per BOE}$$

Note that for the Central and Western Gulf of Mexico the values of Column 8 are $-.960 billion and $-.404 billion respectively. These estimates of negative external costs are actually estimates of economic benefits to the nation of developing the OCS resources of these areas in lieu of importing foreign crude. They represent an environmental windfall when viewed from the national perspective of this analysis. Notice also, that the per barrel costs for the North Atlantic are very close to zero. This is the case since the expected external costs to the nation of developing the resources of the North Atlantic just about balance the expected damages avoided from spills from foreign tanker imports. Columns 8 and 9, which reflect the present value of the external costs (or benefits) of development of all the resources, can be used as a "common base" from which adjustments can be made to compare the present value of expected external costs (or benefits) of various sales and alternatives which the Secretary considers.

The Tables 1 and 2, in the Summary of this Appendix, show a rank order of Columns 8 and 9 respectively for the leasing areas. Comparisons of relative expected external (environmental and socio-economic) costs can thus be made. The second and third columns of Table 2 show the percent of oil out of the total expected BOE of hydrocarbons for each leasing area and the percent of the oil which is transported by tanker, so comparisons can be made between the external cost per BOE and the portion of the BOE which is oil transported by tanker. Such a comparison is useful since, as evidenced by Appendix 8-C-2, a large portion of the total external costs are associated with oil spills from tankers. Oil spill costs, of course, do not occur when gas is produced. Thus, an area with a low percentage of oil out of the total hydrocarbon resource would be expected, all other things being equal, to have relatively low external costs per barrel of oil equivalent.

APPENDICES 8-D-1
THROUGH 8-D-6

Estimation of Expected
External Costs for Each
Alternative Leasing Schedule

Description of Appendices 8-D-1 through 8-D-6

Estimation of Expected External Costs for Each Alternative Leasing Schedule

The external costs for specific sales in alternative leasing programs were estimated from the total external cost estimates for each area. For each sale, the U. S. Geological Survey estimated the percent of the undiscovered recoverable resources in the area that would be leased. These percentage estimates were used not only in developing the estimates of net economic value for each sale, but also to estimate the external costs for each sale. For each sale, the percentage was multiplied by the external costs for total production in the area. The resulting external cost estimate was then multiplied by the discount factor appropriate for the year in which the sale is scheduled. Using the discount factor gives the present value of the external costs of the sale. Tables 8-D-1 through 8-D-6 show the estimates of external costs for each alternative.

Comparison of the estimated external cost of one alternative schedule with another can be misleading since the number of sales, the location of tracts to be offered and the number of years included in the alternative vary. A more useful comparison is to compare the estimated external costs of each alternative with the net economic value for each alternative (see Tables 8-13 of Appendix 2.)

Present Value of Estimated External Costs for Alternative I

Sale	Present Value of Estimated External Costs ($ billions)	
1982, 67 & 69 Gulf of Mexico	-.033*	
68 S. California	.099	
52 N. Atlantic	.004	
71 Diapir Field	.666	
57 Norton Basin	.061	
Total Value 1982		.797
1983, 73 C. & N. California	.139	
70 St. George Basin	.084	
76 Mid-Atlantic	.038	
75 N. Aleutian Basin	.061	
72 C. Gulf of Mexico	-.027	
78 S. Atlantic	.092	
74 W. Gulf of Mexico	-.009	
79 E. Gulf of Mexico	.065	
Total Value 1983		.443
1984, 80 S. California	.070	
82 N. Atlantic	.034	
83 Navarin Basin	.106	
81 C. Gulf of Mexico	-.017	
87 Diapir Field	.411	
84 W. Gulf of Mexico	-.008	
88 Norton Basin	.016	
94 E. Gulf of Mexico	.031	
89 St. George Basin	.063	
Total Value 1984		.706
1985, 90 Atlantic	.064	
85 Barrow Arch	.120	
91 C. & N. Calif.	.106	
92 N. Aleutian Basin	.028	
98 C. Gulf of Mexico	-.016	
86 Hope Basin	.007	
102 W. Gulf of Mexico	-.008	
100 S. Alaska	.091	
103 E. Gulf of Mexico	.027	
Total Value 1985		.419

* A negative estimated external cost is actually an estimated external benefit to the nation as explained in the text of Appendix 8-D-O.

Alternative I (cont.)

Sale	Present Value of Estimated External Costs ($ billions)	
1986, 95 S. California	.046	
96 Atlantic	.031	
107 Navarin Basin	.098	
104 C. Gulf of Mexico	-.009	
97 Diapir Field	.189	
105 W. Gulf of Mexico	-.007	
99 Norton Basin	.012	
106 E. Gulf of Mexico	.027	
101 St. George Basin	.029	
Total Value 1986		.416
Total for Alternative I		2.8

APPENDIX 8-D-2

Present Value of Estimated External Costs
for
Alternative II

Sale	Present Value of Estimated External Costs ($ billions)	
1982, 67 & 69 Gulf of Mexico	-.033	
68 S. California	.059	
57 Norton Basin	.061	
52 North Atlantic	.004	
71 Diapir Field	.666	
70 St. George Basin	.084	
Total Value 1982		0.841
1983, 73 California	.139	
76 Mid-Atlantic	.038	
75 N. Aleutian Basin	.061	
72 & 74 Gulf of Mexico	-.021	
78 S. Atlantic	.092	
83 Navarin Basin	.111	
Total Value 1983		.420
1984, 80 California	.070	
82 N. Atlantic	.034	
87 Diapir Field	.411	
79 & 81 Gulf of Mexico	-.014	
88 Norton Basin	.016	
89 St. George Basin	.063	
Total Value 1984		.580
1985, 85 Barrow Arch	.120	
90 Atlantic	.064	
91 California	.106	
84 & 94 Gulf of Mexico	-.013	
92 N. Aleutian Basin	.028	
86 Hope Basin	.007	
93 St. Matthew-Hall	0	
Total Value 1985		.312
1986, 95 California	.046	
96 Atlantic	.031	
97 Diapir Field	.189	
98 & 102 Gulf of Mexico	-.012	
99 Norton Basin	.012	
100 S. Alaska Basin	.083	
101 St. George Basin	.029	
Total Value 1986		.378
Total for Alternative II		2.5

APPENDIX 8-D-3

Present Value of Estimated External Costs
for
Alternative III-1

Sale	Present Value of Estimated External Costs Costs ($ billions)	
1982, 67 & 69 Gulf of Mexico	-.032	
68 S. California	.059	
57 Norton Basin	.061	
52 N. Atlantic	.004	
70 St. George Basin	.084	
Total Value 1982		.176
1983, 71 Diapir Field	.647	
72 & 74 Gulf of Mexico	-.015	
61 Kodiak	.066	
73 California	.106	
75 N. Aleutian Basin	.061	
76 Mid Atlantic	.029	
Total Value 1983		.894
1984, 78 S. Atlantic	.054	
79 & 81 Gulf of Mexico	-.010	
80 California	.053	
82 N. Atlantic	.004	
83 Navarin Basin	.085	
Total Value 1984		.186
1985, 84 Gulf of Mexico	-.008	
85 Barrow Arch	.095	
86 Hope Basin	.007	
Total Value 1984		.094
Total Alternative III-1		1.4

APPENDIX 8-D-4

Present Value of Estimated External Costs
for
Alternative III-2

Sale	Present Value of Estimated External Costs ($ billions)	
1982, 67 & 69 Gulf of Mexico	-.032	
68 S. California	.059	
57 Norton Basin	.061	
52 N. Atlantic	.004	
70 St. George Basin	.084	
Total Value 1982		0.176
1983, 71 Diapir Field	.647	
72 & 74 Gulf of Mexico	-.020	
61 Kodiak	.035	
73 California	.139	
75 N. Aleutian Basin	.061	
76 Mid-Atlantic	.038	
Total Value 1983		.900
1984, 78 S. Atlantic	.069	
79 & 81 Gulf of Mexico	-.013	
80 California	.070	
82 N. Atlantic	.004	
83 Navarin Basin	.106	
Total Value 1984		0.236
1985, 84 Gulf of Mexico	-.010	
85 Barrow Arch	.120	
86 Hope Basin	.007	
Total Value 1985		.117
Total for Alternative III		1.4

APPENDIX 8-D-5
Present Value of Estimated External Costs for
Alternatives IV-1 and IV-2

Sale	Present Value of Estimated External Costs ($ billions)	
1982, 67 & 69 Gulf of Mexico	-.033	
68 S. California	.059	
52 N. Atlantic	.004	
71 Diapir Field	.666	
57 Norton Basin	.061	
Total Value 1982		0.757
1983, 73 C. & N. California	.139	
76 Mid-Atlantic	.038	
72 C. Gulf of Mexico	-.027	
78 S. Atlantic	.092	
74 W. Gulf of Mexico	-.009	
79 E. Gulf of Mexico	.065	
Total Value 1983		0.298
1984, 80 S. California	.070	
82 N. Atlantic	.034	
81 C. Gulf of Mexico	-.017	
87 Diapir Field	.411	
84 W. Gulf of Mexico	-.008	
100 S. Alaska	.094	
94 E. Gulf of Mexico	.034	
Total Value 1984		0.618
1985, 90 Atlantic	.064	
91 N. California	.106	
98 C. Gulf of Mexico	-.016	
83 Navarin Basin	.106	
102 W. Gulf of Mexico	-.008	
97 Diapir Field	.208	
103 E. Gulf of Mexico	.027	
Total Value 1985		0.487
1986, 95 S. California	.046	
96 Atlantic	.031	
70 St. George Basin	.071	
104 C. Gulf of Mexico	-.009	
99 Norton Basin	.016	
105 W. Gulf of Mexico	-.007	
85/86 Barrow Arch/Hope Basin	.139	
106 E. Gulf of Mexico	.027	
Total Value 1986		0.314
Total for Alternatives IV-1 and IV-2		2.5

APPENDIX 8-D-6
Present Value of Estimated External Costs for
Alternatives V-1 and V-2

Sale	Present Value of Estimated External Costs ($ billions)	
1982, 67 & 69 Gulf of Mexico	-.033	
68 S. California	.059	
52 N. Atlantic	.004	
57 Norton Basin	.061	
Total Value 1982		.091
1983, 73 C. & N. California	.139	
70 St. George Basin	.084	
76 Mid-Atlantic	.038	
75 N. Aleutian Basin	.061	
72 C. Gulf of Mexico	-.027	
78 S. Atlantic	.092	
74 W. Gulf of Mexico	-.009	
79 E. Gulf of Mexico	.065	
Total Value 1983		.443
1984, 80 S. California	.070	
82 N. Atlantic	.034	
83 Navarin Basin	.106	
81 C. Gulf of Mexico	-.017	
84 W. Gulf of Mexico	-.008	
88 Norton Basin	.016	
94 E. Gulf of Mexico	.031	
89 St. George Basin	.063	
Total Value 1984		.295
1985, 90 Atlantic	.064	
91 N. California	.106	
98 C. Gulf of Mexico	-.016	
92 N. Aleutian Basin	.028	
102 W. Gulf of Mexico	-.008	
100 S. Alaska	.091	
103 E. Gulf of Mexico	.027	
Total Value 1985		.292
1986, 95 S. California	.046	
96 Atlantic	.031	
107 Navarin Basin	.098	
104 C. Gulf of Mexico	-.009	
105 W. Gulf of Mexico	-.007	
99 Norton Basin	.012	
106 E. Gulf of Mexico	.027	
101 St. George Basin	.029	
Total Value 1986		.227
Total for Alternatives V-1 and V-2		1.3

APPENDIX 9

Discussion of Individual Planning Areas

Geographical, Geologic and Ecological Characteristics and Other Uses of the Sea and Seabed

This section consists of brief, summary descriptions of the OCS planning areas under consideration. Four areas defined in the July, 1981 proposed program--Washington-Oregon, Aleutian Arch, Aleutian Basin and Bowers Basin--are not discussed. After initial consideration it was determined early in the reapproval process, based on U.S. Geological Survey estimates of resource potential and expressions of industry interest, that these areas possess a very low probability of containing hydrocarbons and therefore do not warrant additional consideration. A similar finding was made with respect to St. Matthew-Hall; however, because this planning area is included in Alt. II, it is described below.

The descriptive summaries below contain 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 OCS oil and gas exploration, development and production activities among OCS physiographic regions.

In addition to highlighting characteristics of the planning areas and their major human uses, the descriptions below highlight major special stipulations which have been used in the planning areas in the past. Stipulations described were developed to protect ecological resources or uses of concern which are unique, or which, because of their proximity to potential oil and gas operations or other reasons, required additional protection. Other forms of protective measures, to safeguard against environmental conditions or protect resources and other uses of planning areas, are contained in regulations and other requirements applicable to all OCS oil and gas operations. Decisions regarding steps necessary to protect resources or uses of concern are almost always site-specific within a planning area and not applicable to the determination of whether the planning area itself can or should be offered for lease.

Quantitative information concerning geographical, geologic and ecological characteristics of OCS planning areas and sea and seabed uses within OCS planning areas is included in Tables 1 and 2. More detailed descriptive information about the planning areas is contained in the Final Supplemental Environmental Impact Statement (EIS), Section IV. Additional information about mitigating measures is contained in Section I of the EIS.

North Atlantic

This planning area combines two areas included in the June 1980 program--the North Atlantic and the Mid-Atlantic. This planning area was formerly divided into two areas because there is a north-south division between major Shelf structures. However, interest in possible hydrocarbon-bearing structures is now turning to the Jurassic reef which extends through both areas. There are also several near shelf basins along the reef which are nearly continuous north to south. As a result of increased interest in the continuous Jurassic reef, there is much less of a rationale for separating the two areas.

There are also compelling reasons for considering the areas as a single planning area, one of which is a result of events which have taken place following sales in the two areas. Exploration activities for both the Georges Bank area and the Baltimore Canyon Trough area are being supported out of southeastern New England. The facility at Davisville, R.I., has aggressively sought petroleum-related industries, and as a result, will probably continue to provide support for OCS activities in both areas. In addition, oil from both areas will probably be transported to New Jersey. Finally, that portion of the coast situated shoreward and between both areas may be affected by oil spills and other aspects of leasing in both areas. Therefore, offering and analyzing tracts simultaneously in both areas insures that the cumulative environmental effects of leasing in both areas will be properly evaluated and thereby facilitates assessment of and planning for onshore support facilities.

There is a slight difference between the southern boundary of the former Mid-Atlantic area and the new North Atlantic planning area. Formerly, the southern boundary of the Mid-Atlantic extended offshore from the Virginia-North Carolina line. Under the current proposal, the southern boundary would be seaward of the southern tip of the Delmarva Peninsula. As explained in Part IV of the SID, a technical adjustment to the July 1981 proposed southern boundary is being considered.

1) North Atlantic (June 1980)

This portion of the planning area contains the Georges Bank basin and a reefal structure on its eastern edge. This is a northeast trending basin which is situated about 75 to 100 or more miles offshore of southern New England. The slope shows some evidence of bottom instability and shifting sands, especially on the shelf. Strong currents are known to exist most of the year.

Average weather and sea state 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, and 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 pelagic 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 insure that appropriate monitoring is conducted and operations 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 be aware of possible conflicts with fishing operations and methods to reduce such conflicts.

2) Mid-Atlantic (June 1980)

A reefal structure is the most favorable geologic condition in this portion of the planning area and generally follows a north-south trend along the slope. Currently, primary interest is seaward of the 200 meter isobath, although there are also structures (and existing leases) along the shelf. Large variations in both topographic and bottom stability along the slope is the chief potential geologic hazard. 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 sea states occur in winter and during tropical storms.

The shoreline is primarily beach, with some wetland behind barrier islands. 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 shoreline is high.

Submarine canyons and a large commercial fishery are characteristic of this portion 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 northern portion of the planning area (June 1980 North Atlantic) have also been utilized in this area.

South Atlantic

The promising geologic features of the South Atlantic hug the shoreline in the vicinity of Cape Hatteras, but otherwise are located roughly at least 25 to 75 miles offshore along 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 important shrimp and other fisheries. Beaches are important nesting areas for marine turtles, and the endangered manatee inhabits the coastal waters.

While not exhibiting the type of submarine canyons south of Cape Hatteras as are found further north, 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 charasteristic 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.

Eastern Gulf of Mexico

The Eastern Gulf of Mexico is characterized by numerous, fairly small potential hydrocarbon structures, which are distributed throughout the planning area. Submarine karst topography, especially along the shelf break, is the major potential geologic problem to be faced for oil and gas operations.

Hurricanes are the dominant weather or sea state factor affecting operations.

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. The shoreline is relatively undeveloped, but heavily used for recreation and tourism. Commerical fishing as well as tourism is of economic importance.

The endangered manatee inhabits this area; critical habitat for the manatee has been designated within the planning area for this species.

Central Gulf of Mexico

This planning area is characterized by many small hydrocarbon productive structures, dispersed throughout the area. Mudflows and slumps in the Mississippi Delta vicinity and gas-charged sediments are the greatest geologic hazards to offshore development. Hurricanes are the weather factor most influencing operations and facility design.

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 utilized to protect them. This area supports a large commercial fishery.

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 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 sea floor. Most provide substrate suitable for highly productive 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 BLM-funded studies. These stipulations require monitoring and provide specifications for drilling fluid and cuttings disposal, as well as restricting the location of oil and gas operations in some cases.

Southern California

The Southern California planning area extends north to Point Conception and includes six major nearshore islands. The Channel Islands off Santa Barbara form the Santa Barbara Channel and Santa Catalina Island demarcates the San Pedro Channel. Promising oil and gas structures are confined primarily to these channels. 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 Cortez Banks. Active faulting and seismicity present the greatest potential hazard for offshore operations. High sea conditions can be caused by extratopical cyclones.

Especially productive and diverse marine communities exist in connection with shallow banks, such as Tanner and Cortez Banks, as well as in the vicinity of upwelling and of converging water masses. A special stipulation requiring biological surveys and imposing restrictions on drill cuttings and fluids disposal and structure placement has been utilized in this area. The islands are important breeding sites for sea birds and for seals, sea otters and other pinnipeds. Whales migrate in the nearshore coastal waters as well. Commercial fishing efforts are concentrated 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 area, as well as 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.

The coastline of Southern California includes extensive beaches, as well as rocky shoreline. The coastal area is well developed, due to the extent of urban areas; Los Angeles to San Diego constitutes almost a continuous urban corrdior. Recreational use of the beaches and other shoreline features is extremely high.

Central and Northern California

The planning area extends from Point Conception to the Oregon border, but currently promising geological features are several discrete basins. The shelf is narrow, extending out only about 30 miles. Geologic hazards include strong motion earthquakes, faulting, slope instability, piecement structures 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. 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 cliffs and offshore rocks, provide important breeding habitat for seabirds and marine mammals--seals, sea otters, etc. Whales also migrate within site of shore along the

California coast. Special stipulations to protect biological resources and to require fisheries traning for oil and gas personnel have been developed for use in this area in the past, 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.

Alaskan OCS Areas

Because of its remoteness, fewer people have the same knowledge of Alaska as they do of the contiguous 48 States. It is harder to develop mental images of the characteristics and uses of the shoreline adjacent to Alaskan OCS planning areas than it is of the coast of California or New Jersey, for example. In particular, it is difficult to comprehend the size of Alaska. The coastline of Alaska is one-third greater than the coastline of the entire contiguous 48 States. Planning areas offshore Alaska contain 66 percent of the acreage in all OCS planning areas--and Alaskan planning areas contain 56% of the acreage in planning areas included in the July proposal. Because of the size of the Alaskan OCS, it is divided into 15 OCS planning areas. Three--Bowers Basin, Aleutian Basin and Aleutian Arc--are not described because they are not estimated to contain any hydrocarbon resources. A fourth, St. Matthew-Hall Basin, is also not estimated to contain hydrocarbon resources, however, since this basin was initially considered for leasing in the draft proposed schedule (April, 1981)--Alt. II--it is described below.

Gulf of Alaska

The Gulf of Alaska planning area includes part of a 900-mile long structural feature paralleling the southern Alaska coast and which may be hydrocarbon productive. Geohazards include active faulting, high seismicity, 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, with Prince William sound and the Copper River delta as major geographical features as well as highly productive areas. Nearshore waters and rivers of the area are important nursery areas and spawning grounds for crab and 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.

The coastline is virtually undeveloped, with only a handful of coastal towns or villages. However, the port of Valdez, the pipeline terminal, is located within the planning area. The fishing industry is extremely productive in the Gulf of Alaska, especially for crab, shrimp and salmon. 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--a stipulation regarding design of wells and pipelines and a stipulation requiring environmental training for oil and gas personnel.

Kodiak

This planning area is offshore Kodiak Island and includes the western portion of the Gulf of Alaska, except for the extreme western portion which is in the Shumagin planning area. The Kodiak planning area contains the Kodiak Tertiary Basins. Geologic, weather and sea state 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 Albatrosss Banks host some of the Gulf of Alaska's greatest concentrations of bird and mammal nesting sites, foraging areas and shellfish nursery areas. 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 ten years. The island is also seeking to expand its fish processing industry.

Shumagin

This planning area is situated south of the Alaskan Pennisula and Unimak Island. It includes two structures identified as possibly containing hydrocarbons--the Shumagin Basin, between Semidi and Shumagin Islands, and the Sanak Basin, northeast of Sanak Basin. Geohazards include volcanism and earthquakes.

The south side of the Alaska Penninsula 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 and crab.

As in the Kodiak vicinity, the islands in the Shumagin planning area also support high concentrations of nesting bird colonies and pinniped habitat.

Cook Inlet

The Cook Inlet planning area extends from the State of Alaska waters to southwest Shelikof Straits. Areas of highest hydrocarbon potential are situated in upper Cook Inlet and the northern Shelikof Straits. In addition to the seismic risk common to southeastern Alaskan planning areas, Cook Inlet experiences shift tidal currents and ice floes for about four months of the year. Geohazards are principally scour and fill, 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 for waterfowl and shorebird nesting, especially Kachemak Bay.

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. Fishing is also an important economic activity in the Inlet. In past lease sales, stipulations similar to those described for the Gulf of Alaska have provided for protection of fishing activities.

North Aleutian Basin

North Aleutian Basin is bordered by Bristol Bay to the northeast and the Alaskan Peninsula and Unimak Island to the 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 volcanos. It is also subject to occasionally severe 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.

Isembek 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.

Subsistence use of the coastal areas, including coastal salmon fisheries, is high.

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, and local erosion.

One of the unique features of the planning area is the Unimak Pass, through which whales and other cetaceans and fur seals migrate. The Pribilof Islands also represent a unique resource, supporting millions of nesting sea birds and most of the world's population of northern fur seals. High concentrations and large numbers of other pinnipeds also inhabit the Pribilofs and the Aleutian Chain.

Subsistence use of the Aleutain 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.

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.

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 largely foreign. East of the planning area, St. Matthew and Nunivak Island, are important waterfowl and shorebird areas (they are wildlife refuges), as is the entire Kuskokwim-Yukon delta which is shoreward, but over 200 miles from the planning area.

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 southern landward boundary of the planning area. The primary hydrocarbon prospect is a large, inner-shelf basin situated generally in the center of the planning area. Geohazards of this area include shallow gas, buried peat layers, and ice-gouged sediments.

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 is rocky cliffs, except for the Yukon River delta in the south. This delta area, as well as St. Lawrence Island, host 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.

Coastal uses include subsistence hunting and fishing. 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.

Hope Basin

Hope Basin is roughly equivalent to Kotzebue Sound and is similar in many respects to Norton Sound to the south. The Seaward Peninsula which separates them forms the eastern boundary of the Bering Strait. A regional arch and several other geologic features are good potential hydrocarbon traps. The most promising area is in the northern portion of the planning area, southwest of Cape Hope. 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.

The shoreline is largely beach, along a low coastal plain. The area is extensively used for breeding waterfowl, shorebirds and seabirds, as well as by non-breeding migratory birds. The area also supports large numbers of breeding marine mammals and is the migratory corrider for the bowhead whale and other endangered and non-endangered marine mammals.

Kotzebue is located in the northern border of the planning area, and with a population of 2500, 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.

Barrow Arch

Barrow Arch is situated in the Chukchi Sea. 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.

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.

Barrow is a major distribution center and regional government and native population center.

Diapir Field

This planning area is characterized by a major offshore basin extending from the Canadian border past the western boundary of the planning area into the Barrow Arch area. Major structures occur only in the eastern portion of the area, whereas the central part is characterized by faulting, particularly at the shelf edge. The geologic and meteorologic conditions are similar to those of Barrow Arch.

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 Barrow Arch, except that bird populations are even higher.

The petroleum operations at Prudhoe Bay dominate the economy of the region. Nonetheless, while these employ many 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.

Table 1
Some Geographical, Geological and Ecological
Characteristics of OCS Planning Areas

Planning Areas	Acreage (million)	Est. Remaining Oil/billion bbl) 2/	Est. Remaining gas (trillion cf) 2/	Threatened and Endangered Species 3/	Marine Mammals 3/	Birds 3/	Fisheries (thous. tons landed) 4/
North Atlantic	95	6.7	28.0	2 birds 5 turtles 6 whales	18 species 7,000 or more breed.		781
June 1980 N. Atlantic		4.0	16.7	"	18 species 7,000 breed.	11.8 mill. (.3 breed.) + mod. shorebirds & br. shorebirds	313
June 1980 Mid-Atlantic		2.7	11.3	"	12 species breed.?	4.9 mill. .34 breed.) + mod. shorebird & br. seabirds	468
South Atlantic	120	1.1	4.3	3 birds 5 turtles 5 whales manatee	30 species (2 breed.) 3,600 breed.	2.3 mill. (1.1 breed.)	211
East Gulf of Mexico	60	1.2	1.3	5 birds 5 turtles 5 whales manatee	25 species (1 breed.) 1700 breed.	300,000 + (130,000 breed.) + seabirds	51
Cen. Gulf of Mexico	45	3.1	33.7	5 birds 5 turtles 5 whales	25 species (1 breed.) 1200 breed.	3.9 mill. (2.8 breed.) + non-br. seabirds	798

Table 1 (con't)

West. Gulf of Mexico	35	1.4	25.4	5 birds 5 turtles 5 whales	"	3.6 mill. (2.6 breed.) + non-br. seabirds	44
So. California	19	1.8	3.1	4 birds 4 turtles 6 whales sea otter	23 species (4-8 breed.) > 100,00 breed.	3 mill. (42,000 breed.)	305
C & N California	38	.9	1.2	5 birds 4 turtles 6 whales sea otter	25 species (5-10 breed.) > 16,000 breed.	4.8 mill. (.62 breed.)	54

1/ L = < 11%, M = 11-49%, H = > 49% of exposed coastline
2/ USGS 1981
3/ Data from BLM offices, reported from numerous sources.
4/ See Table 6 (Section II.B. of SID) for sources.

Table 1 (con't)
Some Geographical, Geological and Ecological Characteristics of OCS Planning Areas

anning Areas	Acreage (million)	Est. Remaining Oil/billion bbl)2/	Est. Remaining gas (trillion cf) 2/	Threatened and Endangered Species 3/	Marine Mammals 3/	Birds 3/	Fisheries (thousand t landed) 4/
lf of Alaska	106			7 whales 2 birds	14 species (3 breed.) >35,000 breed.	high # coastal (mod. br.) >6 mill. seabirds (>3 mill. br.)	336
diak	37			7 whales 2 birds	14 species (3 breed.) >85,000 breed.	"	47
umagin	50	0.9	5.0	7 whales 2 birds	14 species (3 breed.) >25,000 breed.	>9 mill. seabirds (>7 br.) coastal?	with No. Aleut.
ok Inlet	9			7 whales 2 birds	15 species (3 breed.) >40,000 breed.	many mill. coastal (mod. no. br.) >3.5 mill. seabirds (>.5 br.)	7
Aleutian Basin	32	0.5	2.2	8 whales 2 birds	20 species (6 breed.) many thous. breed.	many mill. coastal (very high # br.) >5 mill. seabirds (>3 br.)	149
. George Basin	72	0.7	3.9	8 whales 2 birds	19 species (6 breed.) >2.5 mill. breed.	many mill. coastal >16 mill. seabirds (>9 breed.)	with No. Aleut.

St. Matthew-Hall Basin		?	?	8 whales 1 bird	19 species (6 breed.) many thous.br.	coastal - high #'s >4.5 mill. seabirds (>3.5 br.)	?
Navarin Basin	37	1.1	7.3	8 whales 1 bird	16 species (5 breed.) many thous. br.	coastal-0 seabird?	?
Norton Basin	25	0.3	2.2	5 whales 1 bird	14 species (4 breed.) sev. thous. breed.	many mill. coastal >7 mill. seabirds (>3.5 br.)	2
Hope Basin	15	0.1	1.1	5 whales 1 bird	12 species (3 breed.) sev. thous. br.	high # coast-al >1 mill. sea-birds (.8 br.)	.08
Barrow Arch	29	0.9	4.2	5 whales 1 bird	12 species (3 breed.) mod. high #'s breed.	high # coastal, incl. br. 300,000 + sea-birds--? (.3 mill. br.)	?
Diapir Field	51	2.8	14.8	2 whales 1 bird	8 species (3 breed.) mod. # breed.	high # coastal, (inc. br.) 3 mill. seabirds (few br.)	?

1/ L = < 11%, M = 11-49%, H = > 49% of exposed coastline.
2/ USGS 1981.
3/ Data from BLM offices, reported from numerous sources.
4/ See Table 6 (Section II.B. of SID) for sources.

Table 2
Some Other Uses of the Sea and Seabed
by OCS Planning Area

Planning Area	Commercial Fisheries thousand tons landed	Commercial Fisheries million $	Recreational Fisheries thousand tons 1/	Coastal Tourism 2/ million $	Subsistence Hunting & Fishing Dependence 2/	Military & Aero-space Use	Navigation Zones 3/
North Atlantic	781	609.2	47	2,562	--	M	E
June 1980 N. Atlantic	313	304.1	8	864	--	M	E
June 1980 Mid-Atlantic	468	305.1	39	1,698	--	M	E
South Atlantic	211	175.1	16	9,000	--	H	E
East Gulf of Mexico	51	82.4	10	7,000	--	H	E
Cen. Gulf of Mexico	798	253.1	4	2,000	--	L	E
West. Gulf of Mexico	44	169.3	7	1,000	--	L	E
So. California	305	302.4	9	2,606	--	H	E
C & N California	54	53.9	6	751	--	L	E

1/ See footnotes to Table 7 (Section II.B. of SID) for assumptions and sources.
2/ Data from BLM OCS offices, reported from many State and other sources; data not necessarily comparable.
3/ Navigation zones = traffic separation schemes, fairways, anchorages, etc. which are officially established.
E = existing.

Table 2 (con't)
Some Other Uses of the Sea and Seabed
by OCS Planning Area

Planning Area	Commercial Fisheries thousand tons landed	Commercial Fisheries million $	Recreational Fisheries thousand tons	Coastal Tourism million $	Subsistence Hunting & Fishing Dependence	Military & Aero-space Use	Navigation Zones 1/
Gulf of Alaska	336	544	--	--]	1/3 Native families receive greater than 1/2 of their food from subsistence resources.	L	E
Kodiak	47	55	--	--]		L	--
Shumagin	with No. Aleutian		--	--]		L	--
Cook Inlet	7	10	--	--]		L	E
N. Aleutian Basin	149	181	--	--	Most 30% dependent on subsistence re-souces	L	--
St. George Basin	with No. Aleutian		--	--]	About 2/3 Native families get greater than 1/2 of their food subsistence	L	--
St. Matthew-Hall Basin	?	?	--	--]		L	--
Navarin Basin	?	?	--	--]		L	--
Norton Basin	2	2	--	--]		L	--
Hope Basin	.08	.5	--	--]		L	--
Barrow Arch	?	?	--	--]		L	--
Diapir Field	?	?	--	--]		L	--

1/ See footnotes to Table 7 (Section II.B. of SID) for assumptions and sources.
2/ Data from BLM offices, reported from many State and other sources; data not necessarily comparable.
3/ Navigation zones = traffic separation schemes, fairways, anchorages, etc. which are officially established.
E = existing.

Leasing History, Including Hydrocarbon Potential and Interest of Potential Producers

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.

Table 3 provides pertinent information on past leasing, exploration and production activities by planning area, potential hydrocarbon resources by planning area, and industry ranking of planning areas. These factors all bear on determining potential for discovery of oil and gas resources and the interest of potential producers. However, the interest of potential producers is discussed in detail in Appendix 5.

Table 3

Leasing History and Petroleum Development Information
by OCS Planning Area

Including Hydrocarbon Potential and Interest of Petroleum Producers

Planning Area	Tot. Acres (mil-lion)	Prev. Lease Sales	Tot. Acres Leased (mil-lion)a/	Acres Under Lease (mil-lion)b/	Cumulative production c/ million bbl/oil & cond.	Cumulative production c/ trillion cf/gas	Total Wells e/ Expl.	Total Wells e/ Dev/ Prod.	Est. Re-maining Oil (bil-lion bbl)	Est. Re-maining Gas (tril-lion cf)	Ind. Rank ing f/
North Atlan-tic	139										
June 1980 N. Atlan-tic		1	.4	.4	--	--	4	0	4.0	16.7	8
June 1980 Mid-Atlan-tic		3	1.0	.9d/	--	--	28	0	2.7	11.3	12
South Atlan-tic	99	2	.5	.5	--	--	6	0	1.1	4.3	13
East Gulf of Mexico	58	4	.7	.3	--	--	50	150	1.1	1.6	2
Cen. Gulf of Mexico	46	31	9.4	6.7	5,180	45.8	4411	13,222	3.2	34.9	2
West. Gulf of Mexico	35	22	4.4	2.6	38	2.8	552	1654	1.5	26.3	2
So. Calif.	22	4	1.0	.5	201	.1	198	389	1.8	3.1	5
C & N Calf.	37	2	.6	.3	0	0	34	0	.9	1.2	7

Table 3 (con't)

Leasing History and Pet[illegible]eum Development Information
by OCS Planning Area
Including Hydrocarbon Potential and Interest of Petroleum Producers

Planning Area	Tot. Acres (million)	Prev. Lease Sales	Tot. Acres Leased (million) a/	Acres Under Lease (million) b/	Cumulative production c/ million bbl/oil & cond.	Cumulative production c/ trillion cf/gas	Total Wells e/ Expl.	Total Wells e/ Dev/Prod.	Est. Remaining Oil (million bbl)	Est. Remaining Gas (trillion cf)	Ind. Ranking f/
Gulf of Alaska	133	2	.6	.3			10	0	]	]	14
Kodiak	89								]0.9	]5.0	18
Shumagin	84								]	]	19
Cook Inlet	8	2	.6	.3			9	0	]	]	16
N. Aleutian Basin	32								0.5	2.2	10& 11
St. George Basin	70								0.7	3.9	6
St. Matthew-Hall Basin	51								0	0	4
Navarin Basin	37								1.1	7.3	4
Norton Basin	25								0.3	2.2	9
Hope Basin	12								0.1	1.1	15
Barrow Arch	30								0.9	4.2	3
Diapir Field	49	1	.1	.1			2	0	2.8	14.8	1

a/ POCS rough estimate sometimes with actual data.
b/ POCS estimate using USGS data as of 6/30/81 and sales held through 2/2/82.
c/ Through 1980.
d/ Soon to be .6.
e/ USGS estimate 2/4/82 (R. Prehoda)
f/ Rankings based on response to December 31, 1980 Federal Register notice and apply to different planning area boundaries. Rankings shown are for planning areas closest to that in July 1981 proposed program. See Appendix 5.

Relevant Environmental and Predictive Information

Section 18(a)(2)(H) of the OCS Lands Act as amended requires that the Secretary consider relevant environmental and predictive information in determining the timing and location of exploration, development and production among physiographic OCS regions. However, this consideration cannot be isolated from other considerations included in Section 18(a)(2)--especially subparts (A), (D) and (G).

Consideration of Sections 18(a)(2)(A) and (D) is addressed earlier in this Appendix under "Geographical, Geologic and Ecological Characteristics and uses of the Sea and Seabed". Section 18(a)(2)(G) is discussed in II.B.2 of the SID. Additional predictive information (hydrocarbon resources estimates) is contained under "Leasing History, Including Hydrocarbon Potential and Interest of Potential Producers," in this Appendix.

Additionally, the Final Supplemental Environmental Impact Statement (SEIS) is based on available environmental and predictive information. The SEIS also contains, in Section I.B.7. an analysis of the extent of environmental information available for each planning region. Appendix 8 of the SEIS contains a list of ongoing and completed studies funded by BLM.

Much of the available environmental information on EIS planning areas has been developed through the Bureau of Land Management's OCS Environmental Studies Program.

The environmental studies program was initiated in the Gulf of Mexico in 1973, with an annual budget of half a million dollars. Since that time, it has been expanded to include the entire Outer Continental Shelf. Its budget during the last few years has averaged $35 million annually, resulting in a total of $260 million expended thus far.

The studies program is currently being redesigned in a manner which is compatible with streamlined leasing procedures. Future studies will support acceleration of the leasing process. Consistent with streamlining, there will be a stronger emphasis on detailed analysis of development effects when there is better information available concerning planned activities, rather than the current focus on collection of descriptive data prior to leasing. However, changes in the environmental studies program have been brought about by several factors--not just streamlining. They represent a continuing process of tailoring the program to improve its responsiveness to changing needs and to improve the usefulness of the studies information generated.

Changes have been made in response to recommendations of the National Academy of Sciences and the Interagency Committee on Ocean Pollution Research, Development and Monitoring, and in order to make studies more useful to decisionmakers.

One further consideration is the amount of studies information currently available. Because pre-sale studies have preceded scheduled sales by a few years, studies have already been conducted in all sale areas on the proposed schedule. From one to seven years of studies on biological resources, hazards and physical oceanography will have been completed in all regions by the end of fiscal year 1982.

Under the modified approach, basic information will still be collected through regional reconnaissance studies. Site-specific, pre-sale studies will also continue to be conducted where unique or sensitive sites require study. These efforts, in combination with available information, will provide an appropriate basis for the pre-sale NEPA process.

However, by limiting site-specific, pre-sale studies to those absolutely necessary, in favor of broader reconnaissance studies, increased efforts will be possible in generic fate-and-effects research which will be applicable to leasing decisions in all regions. Additionally, more post-sale, site-specific monitoring studies will be performed. (Such studies are currently underway in Georges Bank and are being initiated in Southern California.) These monitoring studies will be designed in the context of an integrated monitoring strategy developed to provide information on key areas of concern applicable to more than one planning area. They will also draw upon information developed through reconnaissance studies.

In addition to post-sale monitoring, there will be continued reconnaissance studies to provide a long-term data base on critical species and habitats and processes of special concern, tailored to the information needs and concerns in each area. These studies will generally be broader in scope than monitoring studies, providing a basis to detect, for example, effects on popluations or habitat use within a region. Monitoring studies would concentrate on identifying changes in key parameters in exploration and development areas, to evaluate such issues as effects on whale migration and behavior, social effects and space-use conflicts. This combination of complimentary post-sale monitoring and continued reconnaissance, carefully designed to answer questions about specific types of effects, should provide better information for permit evaluations and verification of predicted effects, as well as for pre-sale evaluations of subsequent sales. These post-sale studies, and generic fate-and-effects studies, will also provide the basis for the evaluation of long-term, low level effects of OCS development which has been called for.

In addition to federally-sponsored post-sale studies, industry will be required to perform some post-sale monitoring in all lease areas, probably focusing on near-rig effects of specific exploration and development activities. BLM will carefully coordinate its research activities with those required of industry to avoid duplication and assure that complimentary research efforts are undertaken to develop needed information.

Thus, BLM's strategy is to develop the most appropriate level of detail of information for each decision and to share responsibility for data gathering with industry. A similar approach will be applied to the collection of geohazard data. Rather than collecting tract specific geohazard data in advance of a sale, which results in data collected on some tracts which are not leased, detailed site surveys conducted by industry will be used in evaluating permits. Prior to a sale, geohazard potential will be evaluated based on regional characterizations performed by USGS. These characterizations will concentrate on those portions of a planning area where industry has indicated particular interest or USGS data indicate high potential for petroleum resources, as well as those portions of a planning area, such as slopes, where there is the greatest potential for geologic hazards. Experience in the past few years with tract-specific data collected prior to sales has indicated that these data have been of limited value. Thus, relying on industry site surveys, which was the practice prior to 1976, is much more cost-effective.

Other modifications are also underway to improve the quality of environmental studies and their acceptability. Increasing emphasis is being placed on soliciting advice (through the OCS Scientific Advisory Committee) concerning the design of studies and a peer review procedure is being developed. These actions should help to promote scientific consensus regarding the results of future studies.

The need for studies to support the NEPA process and other pre-sale planning steps is decreasing. In most planning areas, BLM and other agencies have compiled substantial amounts of relevant information. This information is generally sufficient for pre-sale decisions. Future pre-sale planning will rely upon this information. BLM will continue to develop relevant pre-sale information in certain Alaska planning units and other areas as needed. The elimination of detailed, single-sale, site-specific studies, which comprised a substantial portion of the studies budget, will provide support for multi-sale reconnaissance, generic fates and effects stdies, and post-sale monitoring.

A summary of studies completed by planning area is included in Table 4, and a summary of completed and ongoing studies for Alaska planning areas is contained in Table 5.

Table 4

YEARS OF OCS STUDIES INFORMATION FROM EACH LEASE SALE AREA BY TOPIC THROUGH FY 1981

STUDY TOPICS

OCS Area		Endangered Species	Air Quality	Hazards	Socio-Economics	@Fates/ Effects	Cultural Resources	Biology	Physical Oceanography	Baseline
North Atlantic	* (82)	3	0	5	3	4	2	5	5	1
Mid-Atlantic	(83)	3	0	7	3	3	2	5	1	2
South Atlantic	(83)	3	0	6	0	0	1	4	5	1
Gulf of Mexico	(82)	3	0	8	3	2	1	7	3	5
Southern California	(82)	0	3	4	1	0	1	4	2	3
Central and Northern California	(83)	0	2	3	1	1	0	2	2	0
Washington-Oregon	(+)	0	0	0	1	0	0	1	0	0
Cook Inlet	(85)	0	0	5	2	6	1	5	6	2
Gulf of Alaska	(85)	3	0	7	2	2	0	6	6	3
Kodiak	(85)	2	0	5	2	3	1	4	4	1
Aleutian Arc	(+)	0	0	2	0	2	0	2	1	1
North Aleutian Basin	(83)	2	0	4	1	3	0	5	5	1
St. George Basin	(83)	0	0	4	1	3	0	4	4	1
Navarin Basin	(84)	0	0	2	1	0	0	1	2	0
Norton Basin	(82)	3	0	6	1	4	1	6	6	2
Barrow Arch	(85)	2	0	5	1	2	0	6	6	2
Diapir Field	(82)	4	0	5	3	3	1	6	5	2
Hope Basin	(85)	0	0	1	2	0	0	0	1	0

*Fiscal Year of Next Scheduled Lease Sale on July 1981 proposed schedule
+Does Not Appear on July 1981 proposed schedule
@Many Studies in this Group are Generic and Many Apply to Most OCS Areas

Table 5

YEARS OF OCS STUDIES INFORMATION ALASKA OCS SALE AREA BY TOPIC THROUGH FY 1982

OCS Area		Endangered Species	Air Quality	Hazards	Socio-Economics	@Fates/Effects	Cultural Resources	Biology	Physical Oceanography	Baseline
		STUDY TOPICS								
Cook Inlet	(85)	1	0	5	2	6	1	5	6	2
Gulf of Alaska	(85)	3	0	8	2	2	0	6	6	3
Kodiak	(85)	2	0	5	2	3	1	4	4	1
Aleutian Arc	(+)	0	0	2	0	2	0	2	1	1
North Aleutian Basin	(83)	3	0	5	3	4	0	7	7	1
St. George Basin	(83)	1	0	5	2	4	0	5	5	1
Navarin Basin	(84)	1	0	3	2	0	0	2	3	0
Norton Basin	(82)	4	0	7	2	4	1	7	7	2
Barrow Arch	(85)	3	0	5	2	2	0	6	7	2
Diapir Field	(82)	5	0	6	4	3	1	6	6	2
Hope Basin	(85)	1	0	2	2	1	0	1	2	0

*Fiscal Year of Next Scheduled Lease Sale on July 1981 proposed schedule
+Does Not Appear on July 1981 proposed schedule
@Many Studies in this Group are Generic and Many Apply to Most OCS Areas

Appendix 10

Relative Environmental Sensitivity
of OCS Planning Areas--Methodology

Section 18(a)(2)(G) requires that the timing and location of oil and gas activities among oil and gas physiographic regions be based upon a consideration of, among other factors, their relative environmental sensitivity. A decision was made to use the sensitivity of habitats within each planning area to oil spills as the criteria for determining relative environmental sensitivity. This method was chosen for several reasons; among which are:

-- it allows planning areas to be evaluated according to common factors,

-- it avoids uses of overlapping factors (which would result in double-counting some considerations), and

-- it is based on potential oil spill effects, which are considered by many experts to be the greatest measurable biological effect of OCS development.

These and other reasons for choosing this rationale are included in Part II.B.1. of the SID. This section also discusses how other aspects of environmental sensitivity are addressed. In addition to the relative environmental sensitivity rankings based on habitat sensitivity, the SID includes consideration of the relative sensitivities of selected biological resources concern (Table 5 in the SID).

This appendix includes tables indicating how the material presented in Part II.B.1. of the SID was prepared. Table 1 presents the methodology for developing sensitivity rankings for OCS planning areas based on the sensitivity of each habitat and the abundance of each habitat. Table 2 is an example of the calculation of a sensitivity ranking. Table 3 shows how component rankings for each planning area were made to develop planning area rankings.

Table 4 is a summary of the high relative sensitivity rankings included in Table 5 of the SID (Part II.B.1).

Table 1
Methodology
Sensitivity of Planning Area to Oil Spills Based on Habitats

1. Habitat Occurrence Scales:

   A. Wetlands (including marshes, bays, and estuaries), Beaches (including Barrier Islands), lagoons, and Rocky Shores (percent of exposed shoreline)

      L = 0 - 10%
      M - = 11 - 49%
      H = 50% or more

   B. Aquatic Beds

      L = 0 - 999 Sq. Miles
      M = 1000 - 4999 Sq. Miles
      H = 5000 or more Sq. Miles

   C. Reefs/Hard Bottoms

      L = 0 - 249 Sq. Miles
      M = 250 - 749 Sq. Miles
      H = 750 or more Sq. Miles

   D. Submarine Canyons

      L = 0 - 499 Sq. Miles
      M = 500 - 999 Sq. Miles
      H = 1000 or more Sq. Miles

2. Habitat Occurrence Levels Are Multiplicative Factors where:

      L = 1
      M = 5
      H = 10

   Sensitivity to Oil Spill Factors are Additive where:

      L = 10
      M = 50
      H = 300

3. Overall Planning Area Sensitivity to Oil Spills Based on Habitats:

      L = 0 - 999
      M = 1000 - 1999
      H = 2000 or more

Table 2
Example of Sensitivity Rating

North Atlantic
(June 1980)

	Wetland	Beaches	Rocky Shore	Aquatic Beds	Submarine Canyons
Habitat Occurrence	approx. 10% of exp. coast = L = 1	approx. 45% of exp. coast = M = 5	approx. 45% of exp. coast = M = 5	unknown extent assume L = 1	approx. 450 sq. miles = L = 1
Sensitivity to Oil Spills Spill persistence	> 3 years = H = 300	1-3 years = M = 50	1-3 years = M = 50	1-3 years = M = 50	1-3 years = M = 50
Habitat Recovery	1-3 years = M = 50	< 1 year = L = 10	1-3 years = M = 50	1-3 years = M = 50	1-3 years = M = 50
Damage Due to Clean-Up	> 3 years = H = 300	< 1 year = L = 10	> 3 years = H = 300	< 1 year = L = 10	< 1 year = L = 10
	650 x 1 = 650	70 x 5 = 350	400 x 5 = 2,000	110 x 1 = 110	110 x 1 = 110

Overall sensitivity to oil spills based on habitat

= 3220

÷ 5 habitats

= 644 (= relatively low sensitivity; total scores ranged from 457 to 2,865)

Table 3

Relative Environmental Sensitivity of OCS Planning Areas--Sensitivity of Habitats to Oil Spills

	Planning Areas									
	North Atlantic (June 1980)					Mid-Atlantic (June 1980)				
	Habitats									
	Wetlands	Beaches	Rocky Shores	Aquatic Beds not known	Submarine Canyons 450 sq.mi.	Wetlands	Beaches	Rocky Shores	Aquatic Beds not known	Submarine Canyons 540 sq.mi.
Habitat Occurrence	L	M	M	L	L	M	H	L	L	M
Sensitivity to Oil Spills										
Persistence of Oil	H	M	M	M	M	H	M	M	M	M
Habitat Recovery	M	L	M	M	M	M	L	M	M	M
Damage Due to Clean-up	H	L	H	L	L	H	L	H	L	L
Overall Planning Area Sensitivity to Oil Spills Based on Habitats			L					L-M		

	Planning Areas									
	North Atlantic (Proposed July 1981)					South Atlantic				
	Habitats									
	Wetlands	Beaches	Rocky Shores	Aquatic Beds not known	Reefs/Hard Bottoms Submarine Canyons 990 sq.mi.	Wetlands	Beaches	Rocky Shores	Aquatic Beds 33 sq.mi.	Reefs/Hard Bottoms Submarine Canyons 0.74 sq.mi.
Habitat Occurrence	M	H	M	L	M	M	H	N/A	L	L
Sensitivity to Oil Spills										
Persistence of Oil	H	M	M	M	M	H	M	N/A	M	M
Habitat Recovery	M	L	M	M	M	M	L	N/A	M	M
Damage Due to Clean-up	H	L	H	L	L	H	L	N/A	L	L
Overall Planning Area Sensitivity to Oil Spills Based on Habitats			L-M					L-M		

Table 3 (cont.)

	Planning Areas										Planning Areas									
	Eastern Gulf of Mexico					Central Gulf of Mexico					Western Gulf of Mexico					Southern California				
	Habitats										Habitats									
	Wetlands	Beaches	Rocky Shores	Aquatic Beds 3008 sq.mi.	Reefs/Hard Bottoms Submarine Canyons 57.2 sq.mi.	Wetlands	Beaches	Rocky Shores	Aquatic Beds 103 sq.mi.	Reefs/Hard Bottoms Submarine Canyons 39.9 sq.mi.	Wetlands	Beaches	Rocky Shores	Aquatic Beds 778 sq.mi.	Reefs/Hard Bottoms Submarine Canyons 61.4 sq.mi.	Wetlands	Beaches	Rocky Shores	Aquatic Beds 12,761 sq.mi.	Reefs/Hard Bottoms Submarine Canyons 297 sq.mi.
Habitat Occurrence	M	H	N/A	M	L	H	M	N/A	L	L	M	H	N/A	L	L	L	M	H	H	M
Sensitivity to Oil Spills																				
Persistence of Oil	M	M	N/A	M	M	M	M	N/A	M	M	M	M	N/A	M	M	M	M	M	M	M
Habitat Recovery	M	L	N/A	M	M	M	L	N/A	M	M	M	M	N/A	M	M	M	L	M	M	M
Damage Due to Clean-up	H	L	N/A	L	L	H	L	N/A	L	L	H	L	N/A	L	L	H	L	H	L	L
Overall Planning Area Sensitivity to Oil Spills Based on Habitats	L					L-M					L					L-M				

Table 3 (cont.)

	Planning Areas									
	Central and Northern California					Gulf of Alaska				
	Habitats									
	Wetlands	Beaches	Rocky Shores	Aquatic Beds 17,807 sq.mi.	Reefs/Hard Bottoms Submarine Canyons 1,187 sq.mi.	Wetlands	Beaches	Rocky Shores	Aquatic Beds 8,113 sq.mi.	Reefs/Hard Bottoms Submarine Canyons
Habitat Occurrence	L	M	H	H	H	H	M	M	M	N/A
Sensitivity to Oil Spills										
Persistence of Oil	H	M	M	M	M	H	M	M	M	N/A
Habitat Recovery	M	L	M	M	M	M	L	M	M	N/A
Damage Due to Clean-up	H	L	H	L	L	H	L	H	L	N/A
Overall Planning Area Sensitivity to Oil Spills Based on Habitats			M - H					H		

	Planning Areas									
	Kodiak					Cook Inlet				
	Habitats									
	Wetlands	Beaches	Rocky Shores	Aquatic Beds 2,832 sq.mi.	Reefs/Hard Bottoms Submarine Canyons	Wetlands	Beaches	Rocky Shores	Aquatic Beds 126 sq.mi.	Reefs/Hard Bottoms Submarine Canyons
Habitat Occurrence	M	M	M	M	N/A	H	M	L	L	N/A
Sensitivity to Oil Spills										
Persistence of Oil	H	M	M	M	N/A	H	M	M	M	N/A
Habitat Recovery	H	L	M	M	N/A	H	L	M	M	N/A
Damage Due to Clean-up	H	L	H	L	N/A	H	L	H	L	N/A
Overall Planning Area Sensitivity to Oil Spills Based on Habitats			M-H					H		

Table 3 (cont.)

	Planning Areas									
	Shumagin					North Aleutian				
	Habitats									
	Wetlands	Beaches	Rocky Shores	Aquatic Beds 7,035 sq.mi.	Reefs/Hard Bottoms Submarine Canyons	Wetlands	Beaches	Rocky Shores	Aquatic Beds 450 sq.mi.	Reefs/Hard Bottoms Submarine Canyons
Habitat Occurrence	H	M	M	L	N/A	M	H	M	L	N/A
Sensitivity to Oil Spills										
Persistence of Oil	H	M	M	M	N/A	H	M	M	M	N/A
Habitat Recovery	H	L	M	M	N/A	H	L	M	M	N/A
Damage Due to Clean-up	H	L	H	L	N/A	H	L	H	L	N/A
Overall Planning Area Sensitivity to Oil Spills Based on Habitats			H					M-H		

	Planning Areas									
	St. George Basin					St. Matthew-Hall Basin				
	Habitats									
	Wetlands	Beaches	Rocky Shores	Aquatic Beds 17,104 sq.mi.	Reefs/Hard Bottoms Submarine Canyons	Wetlands	Beaches	Rocky Shores	Aquatic Beds 7,900 sq.mi.	Reefs/Hard Bottoms Submarine Canyons
Habitat Occurrence	M	M	H	H	N/A	H	L	L	H	N/A
Sensitivity to Oil Spills										
Persistence of Oil	H	M	M	M	N/A	H	M	M	M	N/A
Habitat Recovery	H	L	M	M	N/A	H	L	M	M	N/A
Damage Due to Clean-up	H	L	H	L	N/A	H	L	H	L	N/A
Overall Planning Area Sensitivity to Oil Spills Based on Habitats			H					H		

Table 3 (cont.)

Planning Areas	Navarin Basin					Norton Basin				
Based on St. Matthew-Hall Is.--all habitats rated low in occurrence due to relative size of coastline	Habitats									
	Wetlands	Beaches	Rocky Shores	Aquatic Beds	Reefs/Hard Bottoms Submarine Canyons	Wetlands	Beaches	Rocky Shores	Aquatic Beds 7,810 sq.mi.	Reefs/Hard Bottoms Submarine Canyons
Habitat Occurrence	L	L	L	N/A	N/A	H	L	L	H	N/A
Sensitivity to Oil Spills										
Persistence of Oil	H	M	M	N/A	N/A	H	M	M	M	N/A
Habitat Recovery	H	L	M	N/A	N/A	H	L	M	M	N/A
Damage Due to Clean-up	H	L	H	N/A	N/A	H	L	H	L	N/A
Overall Planning Area Sensitivity to Oil Spills Based on Habitats			L					H		

Planning Areas	Hope Basin					Barrow Arch					
	Habitats										
	Wetlands	Beaches	Rocky Shores	Aquatic Beds 2,343 sq.mi.	Reefs/Hard Bottoms Submarine Canyons	Wetlands	Beaches	Lagoons	Rocky Shores 2,220 sq.mi.	Aquatic Beds	Reefs/Hard Bottoms Submarine Canyons
Habitat Occurrence	L	H	L	M	N/A	L	H	L	L	M	N/A
Sensitivity to Oil Spills											
Persistence of Oil	H	M	M	M	N/A	H	M	M	M	H	N/A
Habitat Recovery	H	L	M	M	N/A	H	L	M	M	M	N/A
Damage Due to Clean-up	H	L	H	L	N/A	H	L	L	H	H	N/A
Overall Planning Area Sensitivity to Oil Spills Based on Habitats			L					L			

Table 3 (cont.)

Planning Areas

Diapir Field

Habitats

	Wetlands	Beaches	Lagoons	Rocky Shores	Aquatic Beds 3,903 sq.mi.
Habitat Occurrence	M	H	L	L	M
Sensitivity to Oil Spills					
Persistence of Oil	H	M	M	M	H
Habitat Recovery	H	L	M	M	M
Damage Due to Clean-up	H	L	L	H	L
Overall Planning Area Sensitivity to Oil Spills Based on Habitat			M-H		

Table 4

Summary of Relative Sensitivity of Marine Resources to OCS Development by Planning Area

High Rankings

No. Atlantic (6/80):	Pelagic birds (spills and habitat)*, commercial fish and shellfish (pelagic spawning, larvae and nursery grounds, and adult)**
Mid-Atlantic (6/80):	Endangered species (spills)
No. Atlantic (7/81):	see above
So. Atlantic:	Endangered species (spills), commercial fish and shellfish (all stages)
E. Gulf of Mexico:	Endangered species (spills), commercial fish and shellfish (all stages)
C. Gulf of Mexico:	Endangered species (spills), commercial fish and shellfish (all stages)
W. Gulf of Mexico:	Endangered species (spills), commercial fish and shellfish (adults and nursery grounds)
So. California:	Endangered species (spills), coastal and pelagic birds (spills and habitats), marine mammals (habitat) and fish and shellfish (adult)
C & N California:	Endangered species (spills), coastal and pelagic birds (spills and habitat), marine mammals (habitat), commercial fish and shellfish (all stages)
Gulf of Alaska:	Marine mammals (spills and habitat)
Kodiak:	Pelagic birds (spills and habitat), marine mammals (spills and habitat)
Cook Inlet:	Coastal and pelagic birds (spills and habitat), marine mammals (spills and habitat)
Shumagin:	Pelagic birds (spills and habitat) and marine mammals (spills and habitat)
No. Aleutian Basin:	Endangered species (spills), coastal and pelagic birds (spills and habitat), marine mammals (spills and habitat)
St. George Basin:	Endangered species (spills), coastal and pelagic birds (spills and habitat), marine mammals (spills and habitat)

St. Matthew-Hall:	Endangered species (spills), coastal and pelagic birds (spills and habitat)
Navarin Basin:	Pelagic birds (spills and habitat)
Norton Basin:	Endangered species (spills), coastal and pelagic birds (spills and habitat)
Hope Basin:	Endangered species (spills), coastal birds (habitat), pelagic birds (spills and habitat)
Barrow Arch:	Endangered species (spills)
Diapir Field:	Endangered species (spills), coastal birds (spills and habitat)

* "Spill" means resource sensitive to direct effects of oil spills, "Habitat" means habitat sensitive to adverse effects of spills or other aspects of OCS development. These apply to all resources except fisheries resources.

** Sensitivity of fisheries resources was analyzed according to stage in life cycle--spawning, larvae and juvenile (in nursery grounds) and adult--and considered the sensitivity of the fish and shellfish within the habitats occupied at each stage. The stage during which these resources are highly sensitive is indicated.