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Atlantic Outer Continental Shelf Energy Resources: An Economic Analysis

by

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Introduction

In 1973, over 77 percent of the energy consumed in the United States came from two sources: petroleum and natural gas. However, domestic production of both has now begun to fall. Oil production peaked in 1972, while natural gas production will probably have peaked in 1973. This reflects a relatively low and now declining reserve to production (R/P) ratio for both energy sources. In other words, new domestic discoveries of hydrocarbon reserves have not kept pace with expanding demand. As a result, imported crude oil and petroleum products have steadily increased their relative share of the United States energy market in recent years; and natural gas shortages have begun to appear.

In 1973, petroleum imports accounted for almost 17 percent of total domestic energy consumption; while imported natural gas supplied just over 1 percent. Of perhaps more importance, over 36 percent of domestic petroleum consumption was imported, while 4 percent of our natural gas came from foreign sources. Due to transportation difficulties and high costs associated with overseas natural gas, however, the low level of imports does not signify the growing supply-demand gap. For example, Federal Power Commission data indicate that over 11 percent of the 1974 commitments made by gas pipelines may need to be curtailed due to inadequate supply (Jacobs).

The reasons for this relatively recent shift in energy dependence are numerous and complex. Those reasons, however, are beyond the scope of this paper (Adelman, 1972-73; Kalter, 1973). The future possibilities are of greater concern here. Prior to the recent Arab oil embargo and the massive price increases which attended its imposition, many forecasts expected a moderate decline in the relative importance of petroleum and natural gas by 1985. At the same time, a substantial increase in imports of these fuel sources was expected as domestic production continued to decline (DuPree and West; National Petroleum Council, 1972). Although the future is now clouded by the changed economic picture, developing governmental policies, and geological considerations, recent (post-embargo) analyses of future supply and demand indicate the necessity for major policy actions if we are to reduce our dependence on foreign energy sources (Federal Energy Administration, PIB Final Report, 1974; Ford Foundation, 1974). Although higher energy prices may have dramatic effects upon the rate of growth in energy demand, an absolute decline in energy requirements is not foreseen (even if prices maintain their historic highs and other conservation measures are instituted). Consequently, at a minimum, depletions in our existing reserve inventory must be replaced if our dependence on foreign sources is not to increase.

One factor that has direct, but not necessarily immediate, implications for domestic petroleum and natural gas production is the strategy adopted by the federal government with respect to leasing Outer Continental Shelf (OCS) lands. Recognition of this fact has lead to a serious policy debate over the future direction of the nation's energy strategy. On the one hand, many have advocated conservation of energy (reductions in the rate of demand growth) in order that our scarce exhaustible resources can be conserved and major exploration and development programs (such as offshore drilling in frontier areas and development of western coal and oil shale deposits) can be deferred or eliminated (Ford Foundation, 1974). Advocates of this approach argue that conservation is the only immediate solution to our energy dependency problem.

Although recognizing the time lags involved in increased domestic supply development, others assume that the lags would be no greater than those entailed in an effective energy conservation program. Thus, they take a somewhat different view. That is, the United States must develop a large scale program to tap our unknown and undeveloped energy resources for future use. Such a program entails a major effort to increase domestic petroleum and natural gas production by increased leasing of OCS acreage. Development of onshore energy resources would also be required.

Unfortunately, the public debate has centered on these two polar solutions. There is a middle ground; that is, that both demand reduction measures and policies designed to increase supply will be needed over the next 15 to 20 years if our energy dependency on foreign nations is not to increase. The decisions that need to be made may not concern one approach versus the other, but the rate and timing of specific policy actions, on both the demand and supply sides of the equation, to meet society's objectives. As the Project Independence Blueprint Report points out, accelerated supply policies may have a greater effect on energy imports by 1985, regardless of future prices, than conservation efforts. However, supply increases alone will not reduce 1985 imports substantially below present day levels unless prices maintain their very high and artificial plateau. Even in that case, reliance on supply increases may be excessively costly to the national economy and short sighted in terms of resource availability for future generations (Federal Energy Administration, 1974). Demand reduction policies can substantially lessen the strain placed upon our finite energy resources, reduce environmental problems associated with energy production and use, and bring down the cost of movement toward greater energy self-sufficiency.[1]

Anticipating the need for an eventual leasing program of some magnitude in frontier offshore areas, the President ordered the Council on Environmental Quality and the Environmental Protection Agency, in conjunction with the National Academy of Sciences, to study the environmental impact of oil and gas production on the Atlantic Outer Continental Shelf (AOCS) and in the Gulf of Alaska. At the time

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[1]As an example, the Federal Energy Administration (1974) projects 1985 energy imports under $7.00 and $11.00 oil prices, respectively, as follows:

1.	Base Case	10.2 MBD	3.5 MBD
2.	Accelerated Supply	5.0	-0-
3.	Conservation	8.2	1.5
4.	Supply plus Conservation	3.0	-0-

the study was ordered in 1973, the President emphasized that no drilling would be undertaken in these areas until a determination had been made of the environmental impact (U. S. Congress, 1973). The study, released in 1974, developed a list of priority areas for offshore exploration in view of the potential environmental hazards on alternative frontier possibilities (Council on Environmental Quality). Those priorities emphasized that the AOCS, as a whole, was an environmentally safer area in which to begin frontier OCS lease sales than the Gulf of Alaska. More specifically, the report points out that certain areas off the Atlantic coast would be preferred to others. This, in conjunction with estimates of potential oil and natural gas from the Geological Survey (Council on Environmental Quality), have heightened public interest in the possibility of AOCS energy exploration.

However, the formulation of public policy related to this and other OCS areas must, by necessity, consider potential economic, as well as environmental, impacts. Improved information of both types is a critical element required if appropriate tradeoffs are to be made in the decision making process. Potential economic impacts associated with OCS oil and gas resource development can include changes in:

1. consumer prices,

2. governmental revenue,

3. investment requirements,

4. the degree of United States dependency on foreign energy sources over time,

5. regional employment and income in energy related sectors,

6. regional employment and income in sectors which may be adversely affected such as commercial and sports fisheries, tourism and related sectors, and

7. income distribution or equity effects.

The impact development will have upon these economic considerations will depend, in large part, upon public policies adopted. These policies will influence the rate and timing of production, production costs and the degree of resource recovery. They can include, but are not limited to, the following categories:

1. the schedule and location of OCS lease sales,

2. the magnitude or size of a given OCS lease sale,

3. the lease term options used by the management agency,

4. the taxation policies adopted,

5. the resource conservation policies required by the management agency, and

6. the environmental restrictions specified for the development process.

In addition, constraints (physical, technical and economic) relating to the achievement of specified leasing objectives must be considered and the implications estimated.

The particular policy options implemented with respect to the above areas can substantially affect domestic production of oil and natural gas. In all likelihood, tradeoffs between the several economic objectives, as well as between economic, physical and environmental components making up the leasing decision, will need to be made in deciding upon the appropriate policy set. The purpose of this analysis is to provide an improved information base from which such tradeoffs can be established. Specifically, the objective is to empirically estimate the potential economical impacts of various policy options as they relate to the AOCS region.

The focus of this report will be on AOCS acreage available for future leasing and not upon the onshore effects of that leasing. A subsequent analysis will consider the regional onshore aspects utilizing the results specified here. In addition, this report treats the AOCS development question in isolation. That is, impacts upon other potential OCS development areas are not considered. Thus, the implication of a given rate of AOCS development for the rate of development in other OCS areas is not considered. Given some limit to the financial resources available for petroleum exploration and possible constraints with respect to equipment and manpower, AOCS development within a given time frame may require postponement in exploration of other areas. If the objective of public policy is to maximize net social benefits in present value terms, this opportunity foregone or postponed may be a critical element in the overall decision making calculus. The scope of this report does not permit that consideration to be raised.

The study is divided into four main components. In the first, the geology and petroleum potential of the AOCS region is examined and alternative scenarios are developed with respect to the quantity and location of possible hydrocarbon resources. In addition, the potential costs of energy exploration, discovery and production in various regions of the AOCS are described and forecast. Second, current leasing policy and resource management prodedures are discussed. Based upon this discussion, alternative leasing and management policy issues with respect to the AOCS are delineated. Third, an analytical framework is formulated and used to analyze impacts forthcoming from the adoption of such alternative policies. The framework is designed to encompass the elements of expected market behavior when public lands are offered for a lease to the private sector. It considers the interrelationships between economic elements and the geophysical and engineering aspects of any hydrocarbon extraction process. The resulting analytical model is calibrated and verified with historical data and then utilized to evaluate the relevant AOCS leasing policy options, plans and procedures. Finally, the study results will be summarized and possible conclusions for resource management and leasing activity on the AOCS presented.

PART I

Energy Resource Potential and Extraction Cost Estimates

Geologic information provides the foundation from which estimates of resource location, resource type and production costs are derived. In Chapter I, AOCS production possibilities will be discussed. Emphasis will be placed upon the geology of the region and the impact upon potential hydrocarbons types and locations.

In Chapter II, cost estimates for energy development and production in various regions of the AOCS will be derived and discussed. These estimates will take account of possible production locations, climatic conditions, water depths and associated issues.

Chapter I

AOCS Energy Production Possibilities

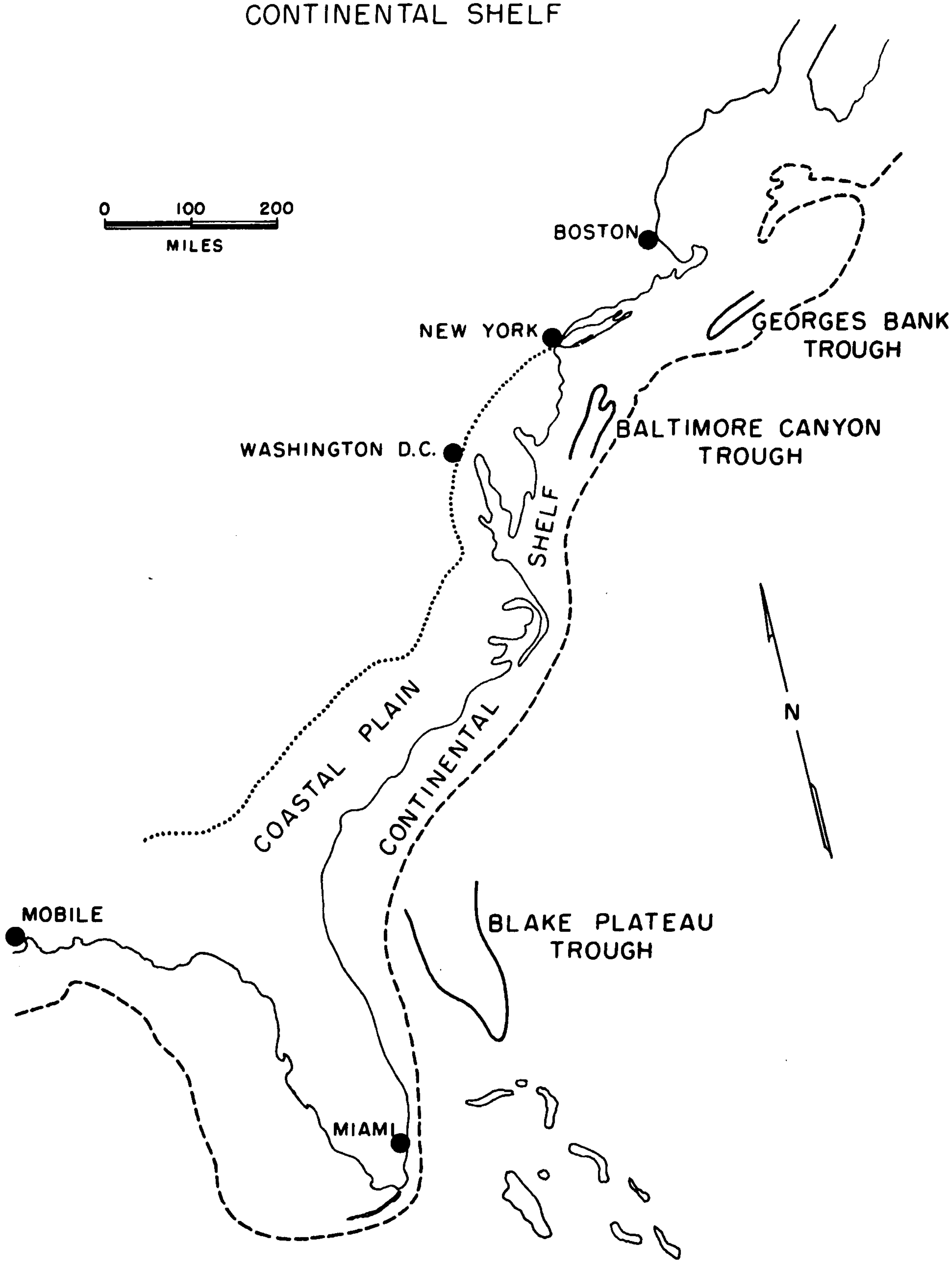
In order to estimate the impact of AOCS development and management policy options upon economic objectives, knowledge is required of potential energy production possibilities. This entails an examination of the physiography and geology of the region in order to arrive at estimates of resource location, fuel type and production costs.

In this chapter, a brief introduction to the geologic potential of the AOCS will be presented. An attempt is made to hypothesize energy resource location by AOCS region and sub-region, by water depth, and by structure depth. This information is used in estimating production costs in the second chapter. The geologic information should be considered as illustrative given the high degree of uncertainty which currently exists in this area. Somewhat more confidence can be placed in the range of production costs. No drilling has taken place on the U. S. portion of the AOCS. Therefore little is known about the geologic potential, and all resource estimates are, by definition, speculative. Nonetheless, it is essential to evaluate all available information on these factors in order to project the possible range of economic consequences from AOCS development under various leasing alternatives.

Geologic Potential: Worldwide there are about eleven million square miles of area in the continental shelves and adjacent offshore areas. The area of the continental shelves adjoining the United States is about one million square miles, of which about 100,000 are off the Atlantic coast (Russell, p. 444; Spivak and Shelburne, p. 1306). The continental shelves slope very gently down to a depth of about 400 feet beyond which the slope steepens, and at about 600 feet the continental slope begins. The Atlantic continental shelf and continental slope are more than 1,250 miles long and range in width from 20 to 300 miles. Along most of the Atlantic coast the shelf is 75 to 100 miles wide, although it is 250 to 300 miles wide off New England and less than 10 miles off southern Florida. Sedimentary deposits (areas of potential hydrocarbon accumulation) on the shelf average 7,500 feet in thickness, and reach 16,000 feet off the New Jersey coast. The deposits continue to thicken beneath the continental slope and may exceed 30,000 feet on the Blake Plateau (see Figure 1). There are many variations in the theory of geologic history which bear on the potential for energy resources being present in such areas. Two will be discussed below.

Wallace Pratt has advanced a theory which considers the shoreline that bounds the shelf toward the land as a hinge line, the coastal side uplifted, and the shelf area downwarped with extensive sedimentation. It follows from this theory that there would be larger and older sedimentary deposits on the shelf than inland, because sedimentation was going on in the continental shelf area while erosion was proceeding on land. These additional sediments could provide favorable prospects for hydrocarbon reservoirs, so that the continental shelf should be expected to have better prospects for oil and gas than the land adjacent to it. Based on this theory, Pratt has estimated that the continental shelves of the United States could contain as much as 1 trillion barrels of oil (Russell, p. 351).

FIGURE I. ATLANTIC COASTAL PLAIN AND CONTINENTAL SHELF



Paul Weaver has suggested another theory in which the shoreline is not the locus of any movement, but that the continental shelf and adjacent land differ only because they are subject to different erosive factors. It follows from this theory that the geologic potential of the shelf would not be expected to be any different from the adjacent coastal areas. Based on L. G. Weeks' estimates of oil reserves on world continental shelves using a similar geologic approach, it appears that the United States Continental shelves could contain about 214 billion barrels of oil.

For the AOCS, a wide range of speculative estimates of recoverable oil reserves have been calculated. This range is due, in part, to the different approaches used for evaluation of wildcat (unexplored) areas. There are two major approaches to calculating speculative reserves (Theobald). One approach, the geological, may incorporate either of the two views of geologic history discussed above. It relates the area or volume of rock potentially containing oil or gas (sedimentary deposits) to known reserves of oil or gas in similar geologic areas. A second approach, the mathematical, projects future trends from past statistics and only implicitly considers trends in geological or technological factors. At the national level, the National Petroleum Council, the U. S. Geological Survey (1972), the Potential Gas Committee, Pratt, and Weeks all use the geological method of calculating reserves. Hubbert of U. S. Geological Survey (1974) and Moore use the mathematical approach (Council on Environmental Quality; Russell; Weeks; Theobald).

Speculative estimates of recoverable oil reserves on the AOCS range from 5 to 20 billion barrels of oil. Those using the mathematical approach to reserve estimation generally arrive at estimates in the low end of the range. The estimates presented and used in this study are based primarily on the geologic approach using the methods developed in a study by Spivak and Shelburne (p. 1306). They estimated the total volume of sedimentary rock on the AOCS and slope and used a factor of 71,000 barrels of oil per cubic mile of sedimentary rock to arrive at recoverable reserve estimates for the area north of the 33° parallel. This factor is based upon average recovery factors for all known hydrocarbon deposits in the United States. For the area south of the 33° parallel a factor of 15,000 bbl. per cubic mile of sediment was used. This was based on estimates of ultimate production and volume of sedimentary rock in several basins of the United States similar geologically to the offshore areas of South Carolina and Georgia. In both cases, recoverable oil was estimated at 40 percent of total oil in place. Estimates of recoverable gas and natural gas liquids were calculated by applying the ratio of expected gas to oil production in the United States as a whole to the AOCS speculative oil reserve estimates. The factor for natural gas was 6.7 Mcf per barrel of crude oil. For natural gas liquids, the factor is .201 barrels per barrel of crude oil (p. 1308). Both associated and nonassociated gas were included in the gas estimate.

Table 1 summarizes the Spivak and Shelburne estimates of speculative recoverable reserves for the AOCS. In addition, estimates from other sources are shown for comparison. All are based upon a geologic approach to hydrocarbon estimation. The variation in estimates can be explained by two principal factors: (1) the delineation of areal extent in the Atlantic and the feasible production areas designated for inclusion in the estimation process, and (2) the expected content of oil and natural gas deposits per unit of sedimentary rock (Council on Environmental Quality, pp. 2-14).

Table 1.-- Estimates of Undiscovered Economically Recoverable Oil and Gas in the Atlantic OCS

	Recoverable Crude Oil (billion barrels)	Natural Gas (trillion cubic feet)
Spivak and Shelburne[1]	10.0	67.0
U. S. Geological Survey[2]	10-20[1]	55-110
National Petroleum Council[3]	5.8	54.5
National Petroleum Council-Potential Gas Committee[4]	19	46
Potential Gas Committee[5]	--	35

[1]The Spivak and Shelburne estimates include 5.30 billion barrels of oil and 36.0 trillion cubic feet of natural gas for the Atlantic OCS north of latitude 33°, .20 billion barrels of oil and 1.0 trillion cubic feet of natural gas for the Atlantic OCS south of latitude 33°. They also estimate that there is 3.30 billion barrels of oil and 22.0 trillion cubic feet of natural gas north of latitude 33° on the continental slope and 1.20 billion barrels of oil and 8.0 trillion cubic feet of natural gas south of latitude 33° on the continental slope.

[2]The U. S. Geological Survey (1974) estimate includes both crude oil and natural gas liquids, so it may be 15 to 20 percent higher than for crude oil only.

[3]The National Petroleum Council (1972) estimate includes 10.75 billion barrels of oil-in-place for the Atlantic offshore area north of latitude 33°, 1.75 billion barrels for the offshore area south of 33° to the Florida boundary, and 1.90 billion barrels for the Florida offshore. The 14.4 billion barrels total was converted to ultimate production with a 40 percent recovery efficiency.

[4]The National Petroleum Council Committee on Possible Future Petroleum Provinces (1970) presents independent estimates of recoverable oil resources but uses the Potential Gas Committee's 1968 estimate for ultimate natural gas production from the Atlantic OCS.

[5]The Potential Gas Committee estimate includes the entire Atlantic offshore area, except Florida, to a depth of 1,500 feet (U. S. Geological Survey, "Comparison and Discussion of Some Estimates of United States Resources of Petroleum Liquids and Natural Gas," 1972).

<u>AOCS Sub-Regional Estimates</u>: The major structural features on the AOCS are the Georges Bank Trough, the Baltimore Canyon Trough, and several areas south of the 33° parallel (including the Southeast Georgia Embayment and the Blake Plateau Trough). Each of these areas has been the focus of recent discussions regarding probable locations for oil and gas production. For purposes of economic evaluation, reserve estimates must be available for sub-regions of these features since cost estimates will vary with hydrocarbon location and the distribution of potential onshore impacts will differ with discovery location.

Table 2 summarizes the results of applying the Spivak and Shelburne estimation methods to sub-regional areas in the AOCS. Based upon our calculations of areal extent for each sub-region (using U. S. Geological Survey maps), structure depth estimates for the various sub-regions (from Spivak and Shelburne) and their hydrocarbon content coefficients for the northern and southern AOCS, potential median resource values were calculated. For each median estimate, a high and low value was computed to bracket a probable range (based upon other studies). The spread was based upon a high value of twice the median and a low of one half the median. The estimates assume that hydrocarbon deposits are spread uniformly over the designated spatial areas in proportion to the volume of sedimentary rock. Hence, potential resource values may be incorrectly distributed if hydrocarbon pooling has taken place in an alternate way (as is highly likely given the size of the regions being discussed). Alternative assumptions regarding the pooling of hydrocarbons can and will be utilized, as appropriate, in the subsequent evaluation to indicate the sensitivity of policy analysis to such factors.

Table 2 divides the Georges Bank area into seven sub-regions, the Baltimore Canyon area into eight sub-regions and distinguishes the shelf from the slope in the remaining areas north of the 33° parallel. South of the 33° parallel, only the shelf and the slope are distinguished. However, in all cases, the resource estimates provided can be classified by water depth and, hence, technological feasibility given current production techniques.

Georges Bank lies about 40 miles off Cape Cod. It is between 200 and 215 miles long and up to 25 or 30 miles wide at its midpoint. The area is represented in Table 2 by sub-regions 1-3. These regions represent the area defined as Georges Bank Proper by the U. S. Geological Survey and the American Association of Petroleum Geologists. Sub-regions 4-6 represent an area which is east of the Bank but west of the continental slope. Finally, the continental slope off of Georges Bank is delineated separately in the Table (sub-region 7). Water depth in the Bank varies from 250 to 660 feet and increases rapidly from 660 to 6,600 feet on the adjacent slope. Structure depth for the sedimentary rock underlying this area has been estimated at between .8 and 2.5 miles thick depending upon the specific sub-region in question. The volume of sedimentary rock, shown in Table 2, for Georges Bank Proper and the area east of the Bank is assumed to be divided equally among the respective subdivisions (each of equal areal extent). On the basis of these volume estimates and using the Spivak and Shelburne content coefficients, a median recoverable reserve estimate of 1.29 billion barrels of oil and 8.6 trillion cubic feet of natural gas is derived.

The Baltimore Canyon Trough lies off the Delaware and New Jersey coasts. It is approximately 125 miles long, about 50 miles wide at its center and 5 to 10 miles wide at its northern and southern extremes. In Table 2, the Baltimore

Canyon area is divided into six sub-regions plus the areas between the Trough and the slope and the adjacent continental slope. Sub-regions 8-10 represent the area that is defined by the U. S. Geological Survey and the American Association of Petroleum Geologists as the Baltimore Canyon Trough. Sub-regions 11-13 represent the area that lies between the New Jersey and Delaware coast and the Trough. Sub-region 14 defines the area between the Trough and the slope, while sub-region 15 refers to the continental slope, itself, off Baltimore Canyon. Water depth in the Canyon and westward varies between 200 and 660 feet, with most of the area lying in 200 to 300 feet of water. On the continental slope, water depth rapidly increases to as much as 6,600 feet. Structure depth for the sedimentary rock underlying this area has been estimated at between 1.4 and 2.6 miles depending upon the specific sub-region in question. The volume of sedimentary rock, shown in Table 2, for the Canyon and the areas west is assumed to be divided equally among the respective subdivisions (each of equal areal extent). On the basis of these volume estimates and using the Spivak and Shelburne content coefficients, a median recoverable reserve estimate of 2.02 billion barrels of oil and 13.53 trillion cubic feet of natural gas is derived.

Georges Bank and the Baltimore Canyon were selected for special consideration because they are the most prominent and promising geologic features off the Atlantic coast. Most experts consider Baltimore Canyon as the area which offers the best potential for significant petroleum discoveries. The remaining acreage on the Atlantic Outer Continental Shelf and slope was not subdivided to a comparable level of detail for this analysis. Rather, the total remaining area north and south of the 33° parallel is shown along with a breakdown between the continental shelf and the continental slope. Although substantial quantities of hydrocarbon deposits might be expected in these areas, in the aggregate, the extent of possible discovery zones does not warrant a further breakdown at this time.[2]

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[2] The area on the Atlantic OCS south of the 33° latitude has a substantially lower potential for oil entrapment than the area north of the 33° latitude. This lower potential is caused by the high percentage of carbonate rock in the area (Spivak and Shelburne, p. 1308).

Table 2.--Potentially Recoverable AOCS Hydrocarbon Estimates by Sub-Region

AREA	Extent	Average Structure Depth	Volume of Sedimentary Rock
	Square Miles	Miles	Cubic Miles
GEORGES BANK AREA			
Georges Bank Proper 1-southern 2-central 3-northern	4,400	1.6	7,040
East of the Bank and west of Slope 4-southern 5-central 6-northern	8,800	.8	7,040
Cont. Slope (7)	1,650	2.5	4,125
BALTIMORE CANYON AREA			
Baltimore Canyon Proper 8-southern 9-central 10-northern	5,500	2.6	14,300
Between Coast and Balt. Canyon 11-southern 12-central 13-northern	5,000	1.4	7,000
Between Trough and Slope (14)	1,300	2.0	2,600
Cont. Slope (15)	2,250	3.0	6,750
OTHER N. ATLANTIC SHELF AREAS (16)	36,000	1.0	36,000
OTHER N. ATLANTIC SLOPE AREAS (17)	18,000	1.9	34,200
TOTAL N. 33°			
SHELF-SOUTH OF 33° (18)	13,600	1.1	15,000
SLOPE-SOUTH OF 33° (19)	21,200	3.7	78,400
TOTAL S. 33°			
TOTAL AOCS			
TOTAL DEVELOPMENT POTENTIAL AOCS[1]			

[1]Based on all areas in less than 1500' of water depth.

Source: Calculations based on National Petroleum Council (1973) and Spivak and Shelburne d

Oil			Gas			Natural Gas Liquids		
median	high	low	median	high	low	median	high	low
Billion Barrels			Trillion Cubic Feet			Billion Barrels		
.50	1.00	.25	3.35	6.70	1.68	.10	.20	.05
.17	.33	.08	1.14	2.28	.57	.03	.06	.01
.17	.33	.08	1.14	2.28	.57	.03	.06	.01
.17	.33	.08	1.14	2.28	.57	.03	.06	.01
.50	1.00	.25	3.35	6.70	1.68	.10	.20	.05
.17	.33	.08	1.14	2.28	.57	.03	.06	.01
.17	.33	.08	1.14	2.28	.57	.03	.06	.01
.17	.33	.08	1.14	2.28	.57	.03	.06	.01
.29	.58	.15	1.94	3.88	.97	.06	.12	.03
1.02	2.04	.51	6.83	13.66	3.42	.21	.42	.10
.34	.68	.17	2.28	4.56	1.14	.07	.14	.03
.34	.68	.17	2.28	4.56	1.14	.07	.14	.03
.34	.68	.17	2.28	4.56	1.14	.07	.14	.03
.50	1.00	.25	3.35	6.70	1.68	.10	.20	.05
.17	.33	.08	1.14	2.28	.57	.03	.06	.01
.17	.33	.08	1.14	2.28	.57	.03	.06	.01
.17	.33	.08	1.14	2.28	.57	.03	.06	.01
.18	.36	.09	1.21	2.42	.60	.04	.08	.02
.48	.96	.24	3.22	6.44	1.61	.10	.20	.05
2.56	5.12	1.28	17.15	34.30	8.58	.52	1.04	.26
2.43	4.86	1.21	16.28	32.56	8.14	.49	.98	.24
8.46	16.92	4.23	56.69	113.38	28.35	1.71	3.42	.85
.23	.46	.12	1.54	3.08	.77	.05	.09	.02
1.18	2.36	.59	7.91	15.82	3.96	.24	.47	.12
1.41	2.82	.71	9.45	18.90	4.73	.29	.56	.14
9.87	19.74	4.94	66.14	132.28	33.07	2.00	3.98	.99
5.71	11.42	2.86	38.27	76.54	19.14	1.16	2.32	.58

Table 3.--Potentially Recoverable AOCS Hydrocarbon Estimates by Water Depth

AREA	Median Oil Estimate by Water Depth		
	0-600'	600-1500'	1500'+
	Billion Barrels		
GEORGES BANK AREA			
Georges Bank Proper 1-southern 2-central 3-northern	.50		
East of the Bank and west of Slope 4-southern 5-central 6-northern	.50		
Cont. Slope (7)		.02	.27
BALTIMORE CANYON AREA			
Baltimore Canyon Proper 8-southern 9-central 10-northern	1.02		
Between Coast and Baltimore Canyon 11-southern 12-central 13-northern	.50		
Between Trough and Slope (14)	.18		
Cont. Slope (15)		.02	.46
OTHER N. ATLANTIC SHELF AREAS (16)	2.56		
OTHER N. ATLANTIC SLOPE AREAS (17)		.12	2.31
TOTAL N. 33°	5.26	.16	3.04
SHELF-SOUTH OF 33° (18)	.23		
SLOPE-SOUTH OF 33° (19)		.06	1.12
TOTAL S. 33°	.23	.06	1.12
TOTAL AOCS	5.49	.22	4.16

Source: Table 2.

Chapter II

Costs of Production

Any economic analysis of OCS leasing behavior must utilize information on production costs in conjunction with resource estimates. However, little comprehensive data, either historical or current, is available from which forecasts of future values can be derived (U. S. Department of the Interior, 1970, p. 161). The situation is further complicated by a number of factors that potentially affect production cost magnitudes. Location considerations, the type or combination of hydrocarbons present, the relationship between production decline rates and production costs, and the type of recovery technology utilized can all influence the level of costs associated with extraction. The material in this chapter examines the production cost concept, reviews the available information relating to it, and provides a range of cost estimates to use when analyzing AOCS production possibilities.

An Overview: This study seeks to analyze private sector behavior under alternative lease policy options but is not concerned with specific actions regarding a given lease sale tract. Consequently, the relevant concept of production cost takes account of conditions in rather broadly defined sub-regions of the AOCS and slope.

Regardless of the spatial focus, however, the costs of extracting hydrocarbons can be classified as either fixed or variable. Fixed (or investment) costs cover the private sector's obligations for resources to provide a given capacity. They do not vary with the level of output once that capacity is installed. Variable (or operating) costs, on the other hand, change with the level of output and can be eliminated by a cessation of production. Although both can occur at various points in the lifetime of an active leasehold, the distinction is a necessary one if the concepts of marginal analysis are to be applied.

It is also conventional, in economic analysis, to use cost curves defined on a per unit of output basis, rather than on the basis of total costs. Although the same information is utilized, per unit values are normally more useful analytically. As indicated previously, a number of factors can interact to define per unit fixed and variable cost curves for OCS hydrocarbon production. First, locational considerations such as water depth, structure (drilling) depth, drilling difficulty, climate and transportation will result in cost differentials among production areas. Second, costs per unit of energy production may vary with the type of hydrocarbons discovered. That is, per unit costs of production from an oil reservoir (which will normally contain associated gas) can differ from those of a natural gas reservoir. Third, producer control over oil reservoir production decline rates can generally be assumed within limits. However, that control, which can be utilized to increase after tax net present value revenue, may increase production costs. Advanced completion technology, installation of pressure maintenance equipment and/or tertiary production techniques may be required. The interaction of these factors with the decline rate and their impact on production costs is complex and difficult to isolate.

Part of this complexity stems from the type of recovery technology used in controlling the decline rate.[3] Some control may be possible utilizing primary recovery (natural reservoir pressures) only. Changes in completion technology and operating techniques will permit this within bounds but usually at some change in production costs. Required investments will normally take place during the initial reservoir development period and operating costs may vary from other primary recovery approaches. Another, but not mutually exclusive, approach to decline rate control entails the use of secondary and tertiary recovery techniques. Again cost requirements will differ from other means of production but, in this case, investment costs can occur at various intervals throughout reservoir lifetime. Operating costs can also vary with recovery techniques. Depending upon reservoir characteristics, advanced recovery methods may be installed with initial development of the reserve, after some period of production, or not at all. A further complicating factor in estimating the cost and timing (required for present value calculations) of such techniques is the effect of their use on recoverable reserves. Whereas primary recovery is only able to extract a percentage of the oil in place, advance recovery techniques will not only affect decline rates but can increase the percentage of oil recovered.

This interaction and the others discussed makes any analytical effort difficult. Even if cost data were available on the various components making up investment and operating costs, the uniqueness of the data with respect to specific reservoirs would make it difficult to generalize about the coefficients of interaction. (Note that the incremental costs and benefits of various production factors need to be known before an adequate analysis can be performed.) Consequently, derivation of production cost schedules will require a set of limiting assumptions.

Assumptions: First, the use of advance recovery techniques to control decline rates and change the ratio of recoverable reserves to oil in place must be considered since it is the most complex of the factors affecting production costs. Fortunately there are several reasons for eliminating consideration of these techniques from the analytical effort undertaken in this report. As the recent Project Independence Blueprint Report (Oil, 1974, p. III-2) pointed out:

> The decision of whether or not to undertake a secondary [tertiary] recovery project is subsequent to a decision to undertake exploration and development of primary reserves. If primary development is economically viable by itself, it is assumed to be undertaken, and the subsequent secondary recovery projects have to stand by themselves.

This assumption has several implications. For our purposes, it implicitly

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[3]In this context, the production decline rate for a leasehold must be distinguished from that for a well system. It is generally standard practice to discuss decline rates in the context of a well system. An alternative concept, however, relates production decline to a leasehold and incorporates changes in the associated well systems, such as well recompletions, new wells and the application of advanced recovery techniques. Since this analysis will be concerned with the economic life of leaseholds, not one well system, the latter concept is the most appropriate definition.

considers a bidding decision by the private sector to be based on primary reserves only. It also considers the decision on advanced recovery techniques to be one made only after a period of primary production. The validity of both implications is an empirical question. However, if the postponement argument is correct, the present value impact on bidding behavior will become less with the passage to time to advanced recovery installation. In general, the industry has tended to postpone advanced recovery until after a period of production but it is unknown whether this decision affects bidding behavior.[4] Given the reduced present value impact, the uncertainty inherent in advanced recovery techniques until after reservoir characteristics are known, and the uncertainty associated with estimates of probable (pre-bid) reserves, ignoring the costs (and benefits) of advanced recovery appears an appropriate first approximation for this analysis. With additional research time and resources, the complex relationships can be investigated for possible incorporation in an expanded analysis.

Second, for this analysis, production costs will be estimated separately for hydrocarbon reservoirs containing primarily oil and those containing primarily natural gas. Oil reservoirs usually produce crude oil, associated natural gas and natural gas liquids. Natural gas reservoirs produce non-associated gas and natural gas liquids. The search for hydrocarbons has become progressively characterized by directional exploratory activities. Evidence presented before the Federal Power Commission showed that the accuracy in distinguishing natural gas from oil reservoirs prior to discovery is higher than 80 percent (Department of the Interior, 1970, p. 164). Thus, much of the initial investment is made for either oil or natural gas reservoirs, rather than total hydrocarbons. One study indicates that approximately 60 percent of all discovery and producing expenditures can be charged against either oil or natural gas (Department of the Interior, 1970, p. 164). The remaining 40 percent consists of dry holes, lease acquisition costs, overhead, geophysical and geological exploration costs, and other exploration costs. For the subsequent analysis, lease acquisition costs and geophysical exploration costs will be excluded, so that wildcat exploratory wells are the only relevant joint production costs.

Based on historical experience in the Gulf and in the Continental United States, it is assumed that 80 percent of the recoverable gas reserves are non-associated and 20 percent associated (Department of the Interior, 1970, p. 174; National Petroleum Council, 1973, p. 367; American Petroleum Institute, Reserves, 1974). Although the rate of production of natural gas liquids in the Gulf has been somewhat higher for non-associated gas than associated gas, their production in the AOCS will be assumed proportional to natural gas production. Thus, for the median AOCS natural gas estimates used in this analysis (66.14 TCF), 52.91 TCF are assumed to be non-associated gas and 13.23 TCF, associated gas. The NPC estimate of non-associated AOCS gas reserves is 54.5 TCF (National Petroleum Council, 1973, p. 367). The comparable estimates of associated and non-associated natural gas liquids are .40 billion barrels

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[4]The Project Independence Blueprint Report (Oil, 1974, p. III-15) assumes that no secondary recovery technology will be installed on AOCS reservoirs until at least ten years after production commences. No tertiary recovery is assumed.

and 1.60 billion barrels, respectively.

The costs of producing associated and non-associated gas and natural gas liquids will be handled differently. For a system producing primarily oil, the incremental cost of producing associated natural gas and gas liquids is small. The only cost difference relates to platform processing and transportation. The cost estimates derived below for oil will include this cost increment. To derive, per unit costs, associated gas and natural gas liquids may be converted to barrels of oil on a value basis and added to total reserves. This procedure has been commonly used in previous work (Weaver, 1972, p. 8; Department of the Interior, 1970, p. 159). For an example of this calculation, assume an oil reserve of one billion barrels. Further assume that the associated gas reserve would be 1.34 TCF, and the associated natural gas liquids would be .04 billion barrels (utilizing parameters of Spivak and Shelburne, p. 1308). If the assumed price of oil is $11 per barrel, natural gas $.50 per Mcf, and natural gas liquids $5.50 per barrel, the oil equivalent of the gas is .06 billion barrels and the natural gas liquids oil equivalent is .02. Therefore, the total hydrocarbon reserve figure for the reservoir is 1.08 billion barrels. Production costs for oil coupled with associated natural gas and natural gas liquids, is handled in this way because a separation of the cost of these joint products would have no economic meaning (Department of the Interior, 1970, p. 164). For non-associated natural gas, production costs will be based upon appropriate modifications of the cost components pertaining to oil reservoirs.

Third, primary recovery costs, for the various hydrocarbon associations, will be different due to locational factors. Production costs relevant to the AOCS are required for this study. However, the Atlantic is a frontier area with no available production data. In such situations, the general procedure has been to extrapolate cost forecasts for known areas using techniques which account for differences in the relevant factors (National Petroleum Council, Ocean Petroleum Resources, 1974). Offshore experience with respect to the Gulf of Mexico and the North Sea are now available for this purpose. Since these two locations bracket most conditions found on the AOCS, they can also serve as a check on the validity of extrapolation results. A number of data sources are examined and compared in the following section. As a result of this comparison, an appropriate basis for displaying per unit cost schedules is chosen and empirical estimates for the AOCS are derived.

<u>Investment Costs - Oil and Associated Natural Gas</u>: A number of factors make up the investment costs required if primary production from hydrocarbon reservoirs is to take place. For convenience, they can be subdivided into two categories: exploration and development costs. Exploration costs include those elements involved in determining the location of hydrocarbons in preparation for drilling development wells and initiating production. Development costs encompass a host of elements required to install production wells, initiate production activity, transport field output to established shore facilities and abandon a depleted field.

Several methods are commonly used to display per unit exploration and development costs.[5] One approach calculates investment cost per barrel of ultimate production (total recovery from the reservoir). Another displays costs on the basis of a "new daily barrel" or "per barrel of daily capacity." That is, the investment cost required to produce a barrel of output daily per year long period. Finally, a variant of the "new daily barrel" approach can be used -- the cost per unit of installed (or peak) annual capacity. This is equivalent to dividing the "new daily barrel" approach by 365. Given the subsequent model to be developed regarding leasing behavior, the latter definition will be used in this study. The result can be compared with the cost per ultimate barrel approach, however, only by making limiting assumptions with respect to factors like field life, decline rate and installed capacity. Since these factors will be products of our model, the definition cannot be used for analytical purposes.

Exploration Costs: Generally all exploratory activities, beginning with geophysical and geolcgical surveys and concluding with the drilling of exploratory wells, are included in exploration costs. However, for an analysis of leasing behavior, only the cost of exploratory wells should be included since most of the geological and geophysical surveying will be done prior to the lease sale. Therefore, these costs can be considered sunk in terms of an investment decision. Furthermore, the cost of geological and geophysical surveys is minimal compared to other exploration and production elements (U. S. Department of the Interior, 1970, pp. 189-91). The cost of exploration, then, is a function of the cost of each exploratory well and the number of wells which are drilled on any given structure or tract. The number of wells required to explore a structure and the discovery efficiency (success ratio) varies significantly among structures (Weaver, p. 13). Discovery efficiency offshore generally averages 10 percent or less, meaning that 10 percent of the exploratory wells are successful in locating commercial hydrocarbon deposits (American Petroleum Institute, Quarterly Review, 1974).

In estimating AOCS exploration costs, estimates from known areas will be used as baseline information from which extrapolations can be made. In this regard, Gulf of Mexico data appears most relevant and appropriate. The National Petroleum Council (Ocean Petroleum Resources, p. 9) has estimated the cost of an exploratory well in the Gulf of Mexico (in 200 meters of water) at $2.7 million. They estimate that nine exploratory wells would be drilled for the average reservoir resulting in exploratory costs of $24.3 million.[6] Exploration costs would not be expected to vary significantly by type of hydrocarbon deposit or by reservoir size.

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[5]Another display often used is that of total system investment costs, rather than per unit values. Given associated estimates of factors like reservoir size, these can be translated to a value on the schedule of unit costs.

[6]A reservoir is not necessarily coterminous with a leasehold. However, unitization is assumed in the analysis. Thus, when reduced to per unit values the derived cost figures can be used for comparable locations and reservoir sizes. Since this study deals with rather broad spatial areas, values pertaining to the average reservoir are appropriate.

Development Costs: Development costs are a function of a number of variables. Some of these are platform costs, water depth, structure depth (drilling depth), percentage of dual completions, dry hole risk factors, drilling difficulty, labor costs, climate, and others. As with exploration costs, Gulf of Mexico cost data can be determined and extrapolated to the AOCS.

Several studies have estimated development costs, by component, for the Gulf. In a draft working paper, NPC scientists have calculated average development costs for application to three reservoir sizes. Coupled with the exploratory costs discussed previously, these estimates provide a basis for determining the total investment costs of reservoirs in the Gulf. NPC assumes that the same exploratory and development expenses will apply to each of the three reservoir sizes considered. Table 4 details these estimates, adjusted to present values.

Table 4.--Gulf of Mexico Investment Costs
(200 meter water depth)

Cost Component	$ in millions	
Development		
2 platforms @ $15 million/unit	$ 30.0	
40 development wells @ $.5 million/unit	20.0	
60 miles of 20" pipeline @ $15,000/inch/mile	18.0	
2 sets of production facilities @ $5 million/unit	10.0	
Storage	2.0	
Future field improvements (recompletions)*	1.6	
Field abandonment*	1.8	
Total development costs		$ 83.4
Exploratory		
9 wells @ $2.7 million/unit		24.3
Total investment costs		$107.7

*Discount to present value using a 12 percent rate, year 8 for future field improvements and year 15 for abandonment.

The production capability of each system is determined by reservoir characteristics. The first system has a peak capacity of approximately 15,000 bbl./day assuming 500 bbl./well/day X 36 producing wells X a .9 maximum efficient rate (MER) constraint on production. The second system has a peak capacity of 30,000 bbl./day assuming 1,000 bbl./well/day and the third system has a peak capacity of 50,000 bbl./day assuming 1,500 bbl./well/day. No secondary or tertiary production costs are included in these estimates. To determine the cost per unit of installed capacity, these oil production rates are adjusted for production of associated gas and natural gas liquids. Converting on a revenue basis as described above, using a $.50 price for gas and a $11 price for natural gas liquids, the oil equivalent peak production levels become 16,517, 33,033, and 55,025 bbl./day. Costs per unit of installed capacity, in 1974 dollars, for each reservoir size are $17.86, $8.93, and $5.36, respectively. This is equivalent to $6,521, $3,260, and $1,956 per new daily barrel.

As a check on these values, several other studies were reviewed. A study done for the Bureau of Mines used another approach for calculating petroleum production costs in the Gulf (U. S. Department of the Interior, Bureau of Mines, 1972). This study calculated all development costs for a 20 and a 30 year oil production model. For the 20 year model, development costs were $32.5 million and installed (peak) capacity was 3,332,000 barrels per year. Costs per unit of installed capacity were $9.75 or $3,560 per new daily barrel. For the 30 year model, cost per unit of installed capacity was $13.34 or $4,869 per new daily barrel. These costs included the development of associated gas and condensate production. Converting these outputs to oil equivalents, the costs per unit of installed (peak) capacity become $8.42 and $11.17, respectively, or $3,073 and $4,077 per new daily barrel. It is not clear in what year these costs were calculated but they appear to be about 1970.

Another study used the cost per barrel of ultimate production approach to cost estimation (U. S. Department of the Interior, 1970). That study calculated all the various exploration and development components and presented the costs per barrel of recoverable reserves added. For the Gulf of Mexico, a range of $1.30 to $1.35 per ultimate barrel resulted. Since no reserve figures were indicated, these results were coupled with several of the NPC reserve and capacity figures. This provides data for a rough order of magnitude comparison to other methods. Using the NPC reservoir of 65 million barrels with a 30,000 barrel peak daily capacity, the costs were $7.87 per unit of installed capacity and $2,871 per new daily barrel. With the NPC reservoir of 175 million barrels and 50,000 barrel peak daily capacity, the costs were $12.71 per unit of installed capacity and $4,638 per new daily barrel. These figures are calculated using $1.325 per ultimate barrel of production. The values are probably in 1968 dollars, but it is not specified in the study.

Table 5 lists the adjusted cost estimates by source and year. This comparison may be misleading, however. Without knowledge of the underlying assumptions used in each approach, derivation of a common unit for display may be inaccurate. As indicated above, underlying assumptions are often not given by the various data sources. For example, the method used to convert cost per ultimate barrel of production to cost per unit of initial capacity was forced to utilize two data sources which were not necessarily commensurate. Nonetheless, the comparison given in Table 5 is useful to gain a rough order of magnitude understanding of production costs on the Gulf.

In reviewing Table 5, the following technical issues should be kept in mind:

Table 5.--Development and Exploration Costs

Source	Unit of Installed Capacity	New Daily Barrel	Year
GULF OF MEXICO			
NPC - 15,000 bbl./day	$ 17.86	$ 6521	1974
NPC - 30,000 bbl./day	8.93	3260	1974
NPC - 50,000 bbl./day	5.36	1956	1974
NPC - average*	10.71	3911	1974
Bur. of Mines - 20 yr. (oil only)	9.75	3560	1970
Bur. of Mines - 30 yr. (oil only)	13.34	4868	1970
Bur. of Mines - 20 yr. (tot. Hydroc.)	8.42	3074	1970
Bur. of Mines - 30 yr. (tot. Hydroc.)	11.17	4076	1970
BLM applied to NPC - 30,000 bbl.	7.87	2871	1968
BLM applied to NPC - 50,000 bbl.	12.71	4638	1968
NORTH SEA			
Lenning	7.73	2820	1974 (Mar.)
Ocean Construction	20.55	7500	1974 (Nov.)

*Derived by calculating a weighted average of the three NPC reservoir sizes assuming equal weights.

1. Figures derived from NPC data assume that total investment costs do not vary with reservoir size. This is clearly a simplification of the real world. Obviously, the number of platforms, well development costs, pipeline costs, and production facility installations can vary with reservoir size. Although the relationship between total costs and the reservoir size may not be linear, the NPC approach would tend to overestimate investment costs for small reservoirs. Consequently, the average NPC per unit investment costs, which are a weighted average of the costs for the three reservoir sizes assuming equal proportions for weights, may be somewhat overstated. It is likely that per unit investment costs actually take on the form of a step function over a range of reservoir sizes.

2. Cost estimates from the three sources listed in Table 5 may relate to different water and structure depths. For example, although the NPC estimates refer to a water depth of 200 meters (600 feet) the Bureau of Mines data relates to 33 meters (100 feet) and the Bureau of Land Management studies to 100 meters or less (300 feet). As a result, per unit costs should be somewhat lower but this would depend upon changes in technology and other factors.

3. The 1968 and 1970 estimates from the Bureau of Mines and the Bureau of Land Management bear an unknown relationship to current production costs on the Gulf. Inflation has tended to increase unit costs since the earlier studies. However, increases in efficiency and technological advances have probably lowered unit costs over the same time period. The net effect of these two forces is uncertain.

The estimates relating to the Gulf of Mexico can be compared with recent studies on the North Sea. It is apparent from these studies that a considerable escalation in investment costs may have taken place recently. However, estimates derived from NPC data tend to bear an appropriate relationship to those of the North Sea, given the locational variations in the two areas. The exception to this is the value for a 15,000 barrel per day reservoir. As indicated above, this value may be excessively high because of the manner in which it was calculated.

AOCS Extrapolation: Given a review of the available investment cost estimates for oil production in the Gulf of Mexico, the next step is to choose an appropriate value (or range of values) for extrapolation to AOCS conditions. Given their currency and apparent consistency with other studies, it appears that the estimates derived by members of the National Petroleum Council would be most appropriate for this purpose.

It must be recognized, however, the unit costs derived from NPC data may not properly specify the relationship between investment and initial installed capacity over various reservoir sizes. Moreover, to obtain an average cost over all reservoirs, the distribution of reservoirs by size must be known. For lack of appropriate information, we assume that equal proportions exist among the three sizes discussed. Implicit is the assumption that equal weights reflect the _a priori_ beliefs of prospective bidders about the distribution. The complex relationships between total initial investment, reservoir size and other geologic characteristics, economies of scale in investment, and other factors determining cost per unit of installed capacity need to be the subject of further research. Nonetheless, we believe the approach used here is an adequate first approximation for this analysis.

Indices necessary to extrapolate Gulf of Mexico cost data to the AOCS have been prepared by the NPC for both exploration and development costs (Ocean Petroleum Resources, pp. 9-11). These values are reproduced in Tables 6 and 7. One difficulty with applying these values to the AOCS is that only the North and South Atlantic are classified, not the Middle Atlantic. Yet the Baltimore Canyon, one of the more promising areas for exploration, lies in the Middle Atlantic. On the basis of conversations with government officials, however, cost estimates for the Middle Atlantic were prepared using the midpoint of two climatic conditions -- moderate and severe. For this purpose, Middle Atlantic was defined as the area between the 33^{o} and the 40^{o} parallels.

Another difficulty with the NPC extrapolation values lies in the fact that they pertain only to water depths of 200 meters or greater. Some geologically promising areas in the AOCS may be in lesser water depths. In that case, costs may be somewhat overestimated, although the magnitude is probably not large.

Table 8 summarizes AOCS production cost estimates for 200 meter water depths, based upon application of NPC extrapolation indices to Gulf of Mexico cost estimates derived from NPC data. An estimate is provided for each of the three reservoir sizes and the average. The average value is the mean cost of the three sizes. Estimates for other than 200 meters are not shown because their values, using current technology, make these areas economically marginal for development. When appropriate, however, they can be calculated in a similar manner and used in the subsequent analysis.

Operating Costs - Oil and Associated Natural Gas: Operating costs for primary recovery of petroleum are less ambiguous than investment costs and more data is available. A number of sources indicate that such costs in the Gulf of Mexico are approximately \$.50 per barrel (U. S. Department of the Interior, 1970; Weaver; National Petroleum Council, 1974). For the AOCS, we will use a value of \$.55 per barrel based upon our conversations with industry people. The sensitivity of model results to this and other cost parameters will be tested in the analytical section.

Production Costs - Non-Associated Natural Gas: In the previous section, all joint exploration costs were attributed to oil discovery. In calculating production costs for non-associated natural gas, we will maintain the same assumption. Therefore, only the development portion of investment costs will be considered here. Although this is an approximation of the actual situation, it is a reasonable approach to apply in wildcat areas as long as the value of crude oil maintains its current high differential with natural gas.

The development cost for non-associated gas should be substantially lower than that for oil reservoirs. Fewer wells would have to be drilled for a comparable size reservoir perhaps eliminating the need for additional platforms. Storage costs would be substantially lower, and other cost

Table 6.--Offshore Exploration Expenditure Indices
(1.0 = $2.7 million per well in 1974 dollars)

Water Depths (Meters)		Climatic Conditions		
		Mild	Moderate	Severe
200	(660')	0.8	1.0	1.8
500	(1,650')	1.0	1.3	2.1
800	(2,640')	2.3	2.6	3.3
4,000	(13,200')	3.8	4.0	4.3

Note: Typical of the various climatic conditions are:

(1) Senegal, Gabon, Honduras, Mediterranean, Java Sea, Persian Gulf.

(2) Gulf of Mexico, South Atlantic, South Pacific, Northwest Australia, Sea of Japan, Yellow Sea.

(3) North Sea, Bay of Biscay, South Australia, Gulf of Alaska, North Atlantic, North Pacific, West Coast of Canada, Nova Scotia.

Table 7.--Offshore Development and Production Expenditure Indices (1.0 = $95 million per system in 1974 dollars)

Water Depth (Meters)		Climatic Conditions		
		Mild	Moderate	Severe
200	(660')	0.9	1.0	2.8
300	(990')	---	---	6.2
500	(1,650')	2.7	3.0	---
1,000	(3,300')	4.3	4.8	10.2

Note: Typical of the various climatic conditions are:

(1) Senegal, Gabon, Honduras, Mediterranean, Java Sea, Persian Gulf.

(2) Gulf of Mexico, South Atlantic, South Pacific, Northwest Australia, Sea of Japan, Yellow Sea.

(3) North Sea, Bay of Biscay, South Australia, Gulf of Alaska, North Atlantic, North Pacific, West Coast of Canada, Nova Scotia.

Table 8.--Atlantic OCS Production Cost Estimates Per Unit of Installed Capacity for 200 Meter Water Depth

	Low	Medium	High	Average
South Atlantic	$ 5.36	$ 8.93	$ 17.86	$ 10.71
Mid Atlantic	9.66	16.11	32.21	19.33
North Atlantic	13.80	23.00	45.99	27.60

components (such as transportation) would be reduced (Garret, 1974). It is estimated that the development cost for associated gas would be about two-thirds of the cost for an oil reservoir. Moreover, the production and decline rate for non-associated natural gas are often institutionally determined. That is, the production rate often must be set low enough to assure a steady supply of gas to meet long term contractual obligations. Hence, production level and decline are a function not only of reservoir characteristics and economic variables but also of institutional constraints. For purposes of per unit cost calculations, the installed capacity will assume that recoverable reserves are depleted in 18 years with a flat production profile. Cost per unit of installed capacity for non-associated gas may then be calculated. Using component cost estimates developed in an earlier study (Department of the Interior, 1970, pp. 205-208) and assuming an 18 year production horizon with a .001 production decline rate, the cost per unit of installed capacity is approximately $1.10 per Mcf. This figure represents the incremental cost of developing a natural gas field assuming that the exploration expenses are allocated to oil production. This cost estimate may be compared with a cost figure of about $1.60, which includes exploration expenses, obtained from proprietory sources. Hence, the estimate appears to be approximately correct. However, more empirical research is needed for verification.

Operating costs for natural gas production ranged from $.04 to $.06 per Mcf in the Interior study (Department of the Interior, 1970, pp. 206-208). In the subsequent analysis an operating cost of $.05 per Mcf will be used.

PART II

The OCS Energy Resource Leasing System

Two lines of inquiry warrant special attention before preceding to an economic analysis of OCS leasing. They include: (1) a description of the present OCS energy resource allocation system and; (2) the identification of policy issues and alternatives for subsequent empirical analysis. Thus, for the purpose of exposition, this portion of the study is divided into two chapters.

The current OCS leasing system will be discussed in the first chapter, with particular emphasis placed upon the existing planning and administrative process. In the second chapter, leasing policy issues are examined, and alternatives for empirical analysis set forth.

Chapter III

Current OCS Leasing Practice

Conceptually, a public leasing system should begin with a planning process and culminate with the development of administrative rules, regulations, guidelines and procedures. Ideally, the planning process is iterative so that the administrative system is continually adjusted in response to changing economic, social and environmental conditions. In order to systematically discuss the current OCS leasing system, it is necessary to outline both the current planning process utilized as well as the administrative procedures flowing from this process.

The Leasing Planning Process: The planning process consists of several distinct yet interrelated elements. The first of these is a concise definition of the relevant objective function which encompasses the principle goals and objectives to be achieved. Subsequent elements include a definition of policy variables or the means of achieving the defined goals and objectives; an information base consisting of resource supply data and demand projections; the formulation and evaluation of alternative programs designed to achieve the specified objectives and; an evaluation of program performance. Ideally the output of the process provides the basis for the definition of desirable changes in policy and also establishes the data and information base upon which administrative decisions are founded.

The Objective Function: The Outer Continental Shelf Lands Act of 1953 (P. L. 212) provides for the jurisdiction of the United States over the submerged lands of the Outer Continental Shelf. In addition, the Act delegates to the Department of the Interior (DOI), the principle administrative and planning responsibilities for the development and management of OCS energy resources. The Act also sets forth three general objectives related to the leasing of OCS lands for energy development: (1) conservation of the resource; (2) receipt of a fair market value for leased resources; and (3) orderly and timely resource development. In addition to the three objectives set forth in P. L. 212, environmental legislation has added a fourth major objective: protection of the natural environment.[7]

Thus, the leasing planning process involves the maximization of a multiple objective social welfare function of the following general form:

1. $SW = f\,(b_1x_1,\ b_2x_2,\ b_3x_3,\ b_4x_4,\ .\ .\ .,\ b_mx_m).$

where x_1 = resource conservation
x_2 = government revenue
x_3 = resource development
x_4 = protection of the environment
x_m = other implicit objectives

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[7] National Environmental Policy Act of 1969; The Federal Water Pollution Control Act Amendments of 1972; and The Marine Protection, Research and Sanctuaries Act of 1972.

The trade-offs or relative weights between the components of this function are represented by b_1 through b_4 and b_m, respectively.

Policy Variables: In addition to providing the foundation for the objective function specified above, the Outer Continental Shelf Lands Act, either by omission or mandate specifies the principle policy variables by which the leasing objectives can be achieved. As mandated by statute, leases must be allocated through a competitive sealed bidding system. However, bidding may be either on the basis of cash bonus or a royalty. Royalty payments, as stipulated, must exceed 12.5 percent of the value of production. The Act does not specify the total acreage to be offered for sale or the frequency of sales, but it does mandate maximum individual lease tract sizes of 5,760 acres. It also provides for the establishment of conservation regulations to prevent waste of energy resources, but specific procedures are not set forth (Public Land Law Review Commission).

Therefore, given existing legislation, the principle policy planning variables include: (1) selection of lands for lease; (2) the size of lease sales; (3) the frequency of sales; (4) the bidding variable; (5) conservation regulations; and (6) determination of royalty above the minimum specified level.

With regard to the first variable, exploratory activities conducted by private industry currently determined to a large extent which OCS areas are selected for leasing. As stated by the Public Land Law Review Commission:

> Although the Outer Continental Shelf Lands Act authorizes the Secretary to issue leases either upon the Department's motion or upon a request describing the area and expressing an interest in leasing, departmental nominations have played a relatively minor role in the selection of areas for lease, apart from drainage sales (p. 87).

Historically, the DOI has also played a passive role in the determination of the size and frequency of lease sales. According to official statements, the analysis of when and how much oil and gas resources are to be offered for lease is determined in part by an examination of projected OCS production in relation to projected demand (U. S. Department of the Interior, Draft Environmental Impact Statement - OCS Sale 32, 1973, p. 4). However, in the past the number of tracts offered and the interval between sales has varied considerably. As stated by the Public Land Law Review Commission:

> There has been no affirmative policy and the timing of sales appears to have been a function of industry demand and varying administrative pressures for increasing revenue to meet the fiscal requirements of the Federal Government (p. 119).

The DOI has always utilized a cash bonus resource allocation system; the royalty rate has historically remained at 16 2/3 percent; and federal conservation regulations have not been promulgated. In summary, the DOI has not attempted to plan for the systematic development of OCS energy resources. This is due in part to a general scarcity of adequate planning data (Kash and White, p. 118).

Planning Data and Information: Presently, much of the necessary planning data and information related to energy resources is collected by private industry and industry associations. Under the present institutional arrangements, the industry is not required to submit geological or geophysical information on unleased areas to the Federal Government. Thus, planning data is limited to that which the government gathers itself or can purchase from the industry. A consequence of this situation is that the government cannot effectively select areas for lease, or effectively evaluate tracts nominated by the industry or their subsequent bids. Moreover, existing data on energy demand is generally deficient as a basis for comprehensive planning and policy making with regard to OCS development. Other data and information problems exist due to the lack of a comprehensive national energy policy and the absence of coordination between offshore development and land use planning programs.

Alternative Program Formulation and Program Evaluation: As a result of the limited information base and the inability of federal decision makers to properly define the relative weights for a leasing strategy objective function, almost no evaluation of alternative leasing programs has been carried out by DOI or the Office of Management and Budget. Consequently, the interdependence of policy variables and the potential impact of their manipulation (both separately and in concert) is not fully understood. This is especially true of the magnitude of such impacts with respect to possible objectives, but often encompasses the direction of the impact as well. The lack of an analytical framework for evaluating alternative leasing policies in an ex ante sense has also inhibited ex post program evaluation. The leasing policy model to be discussed in the third section of this paper is an attempt to provide a preliminary framework for both types of analysis.

Administrative Procedures: As a result of the lack of a comprehensive OCS planning process, the administrative leasing procedures outlined below are designed to react to the initiative of private industry. Thus, the procedures relate primarily to the mechanics of leasing and the preparation of Environmental Impact Statements.

At the outset, it is important to note that within the Department of the Interior, the Bureau of Land Management (BLM) is responsible for implementation of leasing objectives, while the Geological Survey (USGS) has the responsibility for the issuance of permits for pre-leasing exploratory activities and for the supervision and regulation of exploration, development, and production activities after leases are issued. Because of this latter function, they are also primarily responsible for data collection activities.

The administrative system is implemented by the DOI through a procedure consisting of eight major components or procedural steps. The first of these, "the proposed schedule" is utilized by the BLM to determine the timing and initiation of sale procedures. As noted above, the DOI has historically played a rather passive role in this process.

The second component is the "call for nominations" which is an official notice to the industry to nominate tracts which may be offered for lease. Calls for nominations are issued for large contiguous areas and the industry is allowed a period of from 60 to 90 days to submit tract nominations. After nominations have been received, specific tracts are selected by the Department of the Interior for offering. The selection process includes an examination of geologic, engineering and economic information. In addition, tract leasing history, nomination patterns, the degree of competition, and environmental factors are considered. The selected tracts are then published in the Federal Register.

Next, a draft Environmental Impact Statement (EIS) is prepared, public hearings are held, and a final EIS is completed. Throughout the preparation of the EIS, coordination is maintained with other federal agencies. Liason is also provided with state and local groups, as well as with universities. The final EIS is submitted to the Council on Environmental Quality (CEQ).

After the EIS component of the procedure, a "Pre-Sale Evaluation" is undertaken by the Department of the Interior. In essence, the evaluation entails an estimate of the economic value of the tracts offered for lease.

As mandated by statute, the sale is made on the basis of competitive sealed bidding. Following the sale, the DOI undertakes a post sale analysis in order to determine whether leases should be issued. The emphasis of this analysis is upon the receipt of a fair market value. Subsequent to this analysis, a decision to accept or reject the high bid is made. All high bids rejected are subject to appeal to the Board of Land Appeals.

Summary: From the above discussion it is obvious that the leasing policy variables identified do not directly enter either the planning or administrative processes utilized by the Federal Government. To a large extent, leasing policy is determined by two factors: (1) pressure by private industry and (2) receipt of a fair market value for leased resources. Recently, however, public as well as academic debate has focused upon the role of the Federal Government in the planning for and development of Outer Continental Shelf energy resources (U. S. Congress, Senate Interior and Insular Affairs Committee, Hearings on Oversight . . ., 1972; Kash and White). Specifically, the debate has centered around alternatives to the present system and their expected impacts.

Chapter IV

Leasing Policy Issues and Alternatives

As a result of Presidential directives and the increasing domestic energy shortfall, formulation of alternatives to the present Outer Continental Shelf leasing system must be investigated and evaluated. The discussion below will focus upon the issues and alternatives related to federal-state jurisdiction, the selection of lands for lease, the determination of the frequency and size of lease sales, the system of lease allocation, and resource conservation.

Jurisdictional Issues: The development of oil and gas resources of the OCS began as early as 1897 in areas adjacent to the states of California, Texas, and Louisiana. During the 1897 to 1937 period, the states assumed jurisdiction over submerged lands and leases were granted by states for development. In 1937 a Senate resolution was passed which directed the Attorney General of the United States to claim ownership of submerged lands. Debate over state-federal territorial rights continued through 1947 when the Supreme Court decreed that the United States held ownership of submerged lands underlying the Pacific Ocean in the California area. This decision was followed by similar rulings which rejected the ownership claims of Texas and Louisiana to submerged lands adjacent to their coasts (Public Land Law Review Commission, p. 84).

In 1953, the Submerged Lands Act returned jurisdiction over submerged lands to the states. However, the lands conferred to the states by the Act were limited to areas out to three miles from the coastline of the states on the Atlantic and Pacific and nine miles on the Gulf of Mexico. Three months later, the Outer Continental Shelf Lands Act was enacted. This Act established federal jurisdiction over lands outside those ceded to the states by the Submerged Lands Act (Public Land Law Review Commission, pp. 84-85 and chap. 3; Kash and White).

Debate and litigation continues, however, as to federal-state territorial jurisdiction. This issue may play an important role in the development of the AOCS. As pointed out by Kash and White:

> Atlantic coast states do not have state agencies with the oil and gas expertise of those in California, Louisiana and Texas. Thus, a wider potential administrative latitude exists for establishing state-federal intergovernmental cooperation. However, anticipated jurisdictional problems along the Atlantic Coast may result in conflict and delay, possibly to the point of forestalling OCS petroleum resource development.

This prediction has materialized as New York, along with 12 other Atlantic Coast states recently filed a suit before the Supreme Court claiming jurisdiction over the mineral rights of offshore resources. This legal action began on April 1, 1969, "when the federal government initiated suits against thirteen eastern states to enjoin acts of proprietorship over the seabed further than three miles from their coasts" (Corbitt, p. 759). Thus, the basic issues of territorial jurisdiction and hence, ownership of resources potentially worth "trillions of dollars" remains an unsettled issue.

In addition to questions of territorial jurisdiction, other potential jurisdictional issues include pipeline rights of way, coastal zone management and protection of tidal wetlands. As stated by the Public Land Law Review Commission:

> The OCS Lands Act does not authorize the condemnation of rights-of-way across state lands or of sites for onshore facilities where these are necessary or desirable for the efficient operation of OCS leases (p. 126).

Jurisdictional Alternatives: The Outer Continental Shelf Lands Act has not been totally successful in the resolution of jurisdictional issues. Several factors may account for the continued dispute. Historically, arguments have been advanced that OCS activities have had an adverse fiscal and environmental impact upon coastal states. Thus, revenue sharing of OCS proceeds has been suggested as a means to mitigate opposition to OCS development (Corbitt). Such a solution has been successfully adopted by Australia through enactment of a program which divides OCS revenues between the Commonwealth and the states. Under the Australian program, forty percent of revenues accrue to the Commonwealth and sixty percent to the states (Corbitt).

With regard to the United States, two alternatives are obvious: (1) compensatory payments to states; and (2) direct revenue sharing. The first alternative would require the Federal Government to compensate states for net fiscal burdens and for environmental damages not covered by company liability. There is, however, substantial debate as to the magnitude of net fiscal burdens accruing to coastal states as a result of OCS development. Arguments have been advanced that state governments must provide public services, with no hope of compensatory tax collections, in order to accommodate OCS activities. However, it has also been argued that OCS development induces an increase in state revenue through the generation of increased regional economic activity and, thus, state taxes. The net fiscal burden imposed by OCS development remains an unsettled issue, which has not been subjected to quantification.

A program to share a fixed proportion of OCS revenues with coastal states could have a significant impact upon the federal revenue obtained from leasing activities. Moreover, in the AOCS area north of Chesapeake Bay, the determination of which states receive revenue is extremely difficult. In some cases, three or more states could claim to be adjacent to potential development areas. This situation could result in considerable litigation. Thus, no attempt is made in this study to recommend either alternative. Rather the purpose is to provide a quantitative analysis of the impact of alternatives which are relevant to the development of AOCS oil and gas resources. The manner and time frame in which jurisdictional issues are resolved will directly impact the economic objectives to be analyzed.

Lease Allocation Issues: As outlined previously, the current lease allocation system consists of a cash bonus bidding procedure. According to its proponents:

> This system has the economic advantage of substituting market forces for administrative judgments, and because a bonus must be paid before the lease is issued, (20%),

> it tends to insure the selection of an efficient producer. Presumably, the more efficient the producer, the lower his cost and the higher his bid (Kauffman).

The system does, however, have economic disadvantages to private firms in that a substantial investment is required before knowledge of production potential is obtained. It also assumes that all bidders have the same knowledge as to the potential value of the tract. Moreover, the bonus system may force several competing firms to undertake exploratory activities in the same area. The private market nature of the bonus bidding system also diminishes the opportunity for the achievement of social objectives other than the maximization of government revenue. For example, alternative systems such as an administrative system could allow for the sale of leases at less than a "fair market value" in order to achieve other social objectives. As Kauffman points out:

> ... under a competitive bidding system the price is set in the market place, and it is difficult to adjust terms to achieve national objectives other than revenue raising.

Questions of competition and equity have also been raised with regard to the present cash bonus bidding system. In essence, the system requires a substantial initial capital investment, which results in a bias in favor of the major petroleum companies. Historically, major companies, individually or in combination, have controlled approximately 81 percent of leased acreage and 97 percent of production, while independents have controlled only 19 percent of the acreage and 3 percent of the production (Corrigan, p. 1112).

The impact of the bonus bidding system upon OCS production is another issue which has not been resolved. William A. Vogely of the Interior Department, has stated that, "The amount of oil and gas that will flow from the OCS in the next 10 years is primarily a function of the size and timing of the lease sales, not the leasing system" (Corrigan, p. 1116). However, opponents of the system argue that the present cash bonus system retards the development of offshore oil and gas production and that OCS investment would become more attractive under alternative systems of lease allocation such as a deferred bonus bid system or a royalty bid system. Such alternatives, it is argued, would release capital for immediate exploration and development offshore and permit the exploration of more alternatives within a given time frame.

Finally, the lease term has become an issue. The Outer Continental Shelf Lands Act requires a lease term of five years, and so long thereafter as authorized operations are conducted. The Public Land Law Review Commission concluded that the five year term has been adequate in the past. However, in some Outer Continental Shelf areas, drilling operations may only be feasible for portions of a given year (pp. 123-124). This situation can result in areas such as the AOCS or the Gulf of Alaska where oceanographic and weather conditions may be severe and where drilling in very deep waters may ultimately be necessary. Under these conditions, a longer lease term may be desirable.

Alternative Systems of Lease Allocation: Many alternative systems of lease allocation have been proposed. As stated by the Public Land Law Review Commission:

> Although the issuance of . . . leases with fixed royalty through bonus bidding has returned substantial revenues to the federal government, greater flexibility in lease terms and the means by which leases are allocated might benefit the federal government by encouraging additional exploration and development (p. 132).

Alternative lease systems include: (1) installment bonus bidding; (2) royalty bidding; (3) a change in the royalty system; and (4) a negotiated concession system. Options two and three could be implemented under existing statutes. The first and fourth options would, however, require new legislation.

According to its proponents, an installment bonus system might increase the rate of OCS energy development because the initial capital requirement would be reduced. Under this system, cash payments are made at specific intervals. Two options are possible: (1) installment payments with the right to terminate and; (2) installment payments without the right of termination. However, in either case, government revenue could be substantially affected. The effect on government revenue depends, however, on two opposing forces. The first is that since the government shares the risk, higher bonus bids might be expected. In opposition, however, nonproductive leases would create little revenue.

Royalty bidding has been suggested as another approach to resource allocation which would free capital for immediate exploration and development. There is also a contention, but no data to support the hypothesis, that government returns on a present value basis would be larger than those received through the present system. This is based on the assumption that bonus bids are sharply discounted for risk. Department of the Interior officials have, however, calculated that a 70 percent royalty would have to be imposed to equal the government revenue realized under the existing system (Corrigan, p. 1112).

A royalty system carries with it an inherent resource conservation problem. The bonus bid represents a "sunk cost" which does not enter into the decision whether or not or how fast to produce. On the other hand, a royalty bid may lead to early abandonment of marginal fields since the royalty affects the producer's income per unit extracted.

Changes in the royalty system have also been suggested as an alternative to the present fixed rate. Two options are available under existing legislation: (1) increases in the royalty rate; and (2) establishment of a sliding scale of royalty rates. An increase in the royalty rate could conceivably lead to a decrease in bonus bids, thus reducing the initial capital requirements. However, the extent to which capital would be released is in doubt. A sliding royalty system, on the other hand, could be utilized in conjunction with a cash bonus bid to provide a system with the flexibility to respond to changing energy and financial situations. It is possible that the royalty rate could be linked to government objectives in such a way as to provide an automatic adjustment mechanism which would respond to changes in the level of achievement of relevant objectives. As such the system operation could be somewhat analogous to the built-in adjustment mechanism provided by the federal income tax structure.

Most countries other than the United States utilize a negotiated concession system for OCS leasing (Kauffman, p. 248). In other words, the government makes an administrative determination on leasing as opposed to the market system utilized in the United States. Such a system has economic advantages as well as disadvantages. For example, there is no duplication on the part of the industry in the collection of data and information. The major advantage to the government is that the system is flexible to achieve objectives other than government revenue. However, the administrative cost is substantial. In addition, procedures to insure expeditious development of the resource must be incorporated into the system. Aside from economic considerations, it is obvious that a negotiated concession system is wrought with political difficulties. Thus, there appears to be little interest in this alternative at the present time.

The impacts of the alternative leasing options discussed above are speculative in nature at this time. The pros and cons given for each have been based largely upon subjective judgment. There is virtually no empirical data or analytical models available by which the impacts of the various systems can be determined. Thus, a major focus in the future needs to be the development of analytical models and to empirically derive the impacts of alternative energy resource allocation systems.

The Location, Size and Frequency of Lease Sales: The amount of OCS production realized, as well as government revenue, is a direct function of the size, frequency and location of lease sales. It may be anticipated that an accelerated schedule with the addition of leasing in new areas will lead to more petroleum production. On the other hand, there could be an associated decline in government revenue received due to lower bids as a result of more sales and a larger total volume of acreage being offered. There is evidence that:

> Successive Secretaries of Interior have pursued a policy of pacing out the development of OCS oil and gas resources, with leases being parcelled out at a rate that has kept the offshore industry hungry and bonuses high (Kash and White, p. 171).

Moreover, the leasing schedule has been sporadic. As stated by Thomas D. Barrow, President of Humble Oil and Refining Company, "the leasing schedule has caused a feast-or-famine cycle for industries operating offshore" (U. S. Congress, OCS Policy Issues, 1972).

As noted previously, the DOI has played a very passive role in the process of the selection of lands for lease, and the size and frequency of lease sales. Prior to the 1973 Energy Message, the only leasing schedule which had been formulated by the Department of the Interior was published in 1971. To many observers, in light of environmental issues and the current and projected domestic energy shortfall, this is no longer desirable.

In the 1973 Energy Message, the President directed the Secretary to develop a long term leasing program based upon the nation's energy, economic and environmental objectives (U. S. Congress, 1973). The formulation of such a program will require an analysis of the impacts of alternative lease strategies. Such an analysis must consider:

1. Inclusion of additional objectives in the decision making calculus.

2. Estimation of and public disclosure of the impacts of alternative schedules upon the relevant objectives.

3. Improved information of OCS production potential and energy demand.

With regard to the objectives pertinent to the decision making process, economic efficiency, balance of payments, consumer prices, and regional income are relevant. The inclusion of these economic objectives would complement and clarify the present economic objectives of "orderly resource development" and government revenue.

Empirical estimation of the impact of alternative schedules is necessary since management decisions are often made without a consideration of the full range of alternatives and their associated impacts. Public disclosure of such information could facilitate the decision making process throughout.

As noted previously, data and information on energy reserves, resources and energy demand are generally deficient as a basis for comprehensive planning and policy making with regard to OCS energy development. Several options have been suggested (Kash and White, pp. 152-157) with regard to geological and geophysical data, including:

1. Governmental collection of geological data.

2. Industry submission of all data to the USGS or BLM.

3. Combinations of the above.

Resource Conservation: Energy resource conservation is also a policy issue with regard to OCS development. As defined by McDonald, the socially desirable function of resource conservation is, "to achieve or maintain from the point of view of society, the maximum present value of the natural resource" (McDonald, 1971, p. 71). Given this definition, optimum development takes place to the point where no gain can be obtained from shifting production from one time period to another. The economic optimum rate of development includes consideration of how fast a given reservoir should be depleted. This involves a consideration of the number of wells to be drilled in a given reservoir and the rate of development associated with each well. Administrative determination of the number of wells to be drilled and production restrictions directly impact the time stream of production, production costs, industry income and government revenue. Historically, production restrictions and the unitization requirements of coastal states have generally been applied to OCS lands under federal jurisdiction. However, for frontier areas such as the AOCS, federal guidelines have not been developed nor have procedures been promulgated by individual states.

The important aspect of conservation regulation is the potential impact upon the time stream of production and production costs. In the past, production quotas have been applied to allocate production over time and among many producers. These quotas have been based upon a dual concept of: (1) the maximum efficient rate of production from the standpoint of the physical characteristics of the reservoir; and (2) maintenance of a preferred product price through production restrictions based upon market demand. Given present market conditions, the latter concept does not apply and the time stream of production is essentially based upon the

the physical characteristics of the field. This ignores the economic concepts of conservation. In addition, the relationship between production and production cost is largely ignored in the present conservation system. As stated by the Public Land Law Review Commission:

> Continuation of the present system . . . without recognition of operating costs could reduce individual operator margins to the point where further development of outer continental shelf resources beyond a given water depth will become unattractive and reduce bonus bids and competition for them (p. 122).

Additional Considerations: Additional policy issues relevant for empirical analysis include: (1) deregulation of natural gas prices; (2) extension of the investment credit to exploratory wells; and (3) adjustments in the depletion allowance system.

Each of these issues relates directly to the complex system of economic and institutional incentives underlying the production of oil and natural gas. For example, deregulation of natural gas prices may provide an economic incentive to increase exploratory activities and, hence, production.

Summary: Over the past several years, debate has focused upon many aspects of the current Outer Continental Shelf leasing system. This debate has tended to center upon the trade-offs implicit in the current leasing and management system between government revenue, environmental protection, and the desire to develop domestic energy resources. As stated by Kash and White:

> There seems to be ample evidence that the pace of OCS leasing has been determined more by a desire for revenue than on the basis of an assessment of the portion of total energy requirements that is desirable to obtain from the OCS (p. 188).

John D. Emerson, a petroleum economist at the Chase Manhattan Bank, presents the situation as follows:

> The first thing we need to do is to sit down and say, what are our objectives - money for the treasury or more oil and gas (Corrigan, p. 1110).

Although many alternatives to the present leasing system have been proposed, there is a total lack of quantitative analysis between the alternatives and the relevant objective function. An analytical model to fill this void will be discussed next.

PART III

Analytical Framework and Empirical Results

The previous sections have discussed AOCS geology and production cost estimates, along with background on the current OCS leasing system. Out of the background review, a number of policy issues and alternative leasing strategies were developed. It remains to specify an analytical framework that can be used to compare these alternatives and to apply the resulting evaluation model to both general leasing problems and forecast conditions on the AOCS.

Chapter V will set forth such a framework incorporating economic, geological and engineering aspects of the hydrocarbon investment and extraction process. In addition, the role of uncertainty and the assumptions that must be made to apply the resulting model will be outlined. In Chapter VI, the model will be utilized to evaluate public policy alternatives which are relevant to all OCS leasing and which will have an important bearing on AOCS leasing results. Alternative bid systems, issues related to uncertainty and relationships between production costs and decline rate control will be explored. Chapter VII will discuss the application of the model to the AOCS, outline the empirical results and explain their significance with respect to economic impacts.

Chapter V

An OCS Leasing Model

In recent years several economic models of the petroleum investment and production decision process have been developed (Adelman; Baughman; Bradley; MacAvoy and Pindyck; National Petroleum Council, 1972). However, none are directly applicable to the analysis of alternative leasing strategies. Previous formulations have often failed to consider the interface between economic and engineering phenomena relevant to such decisions. For example, with few exceptions, the dependence of recoverable reserves upon the rate of production is ignored (Kuller and Cummings). More importantly, possible control of production decline rates, within reasonable limits, by petroleum producers is generally not recognized by empirical studies (VanMeurs). Finally, important economic considerations, such as risk and taxation, are seldom accounted for in a comprehensive manner.

The analytical framework presented here incorporates the above factors in a model of aggregate private market response to public energy leasing strategies. Engineering and economic considerations are included so that a wide range of public policy alternatives, as well as physical phenomena, related to petroleum production and investment decisions may be quantitatively examined.

The framework is based upon the assumption that there is a known quantity of oil in place, R. The total resource or production constraint can then be represented by:

(1) $$xR \geq \int_0^T q(t)dt,$$

where R represents original oil in place, x is a percentage indicating the maximum oil in place that is physically recoverable given current technology, T is the production time horizon, and q(t) the rate of production. Theoretically, when public lands are offered for lease, an optimum is obtained by the private sector through maximization of net present value revenue subject to this constraint (Kuller and Cummings). The complexity of this optimization problem is largely due to the unknown function q(t). The problem can be simplified if q(t) is expressed as a function of the initial capacity installed and the production decline rate such that (Adelman; Arps; Baughman):[8]

(2) $$q(t) = q_o e^{-at},$$

where q_o represents initial installed capacity, and "a" the rate of decline in production. This relationship is based upon the premise that as petroleum is extracted, natural reservoir pressure is reduced so that pro-

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[8]Both of these variables are assumed to be subject, within limits, to producer control, as is the production time horizon. Depending upon the physical characteristics of the petroleum province and the specific technology utilized, alternative function forms may be specified (Arps; U. S. Department of the Interior Officials).

duction declines through time at the rate "a" (Kuller and Cummings; McDonald, 1967). The rate of pressure reduction, and hence production decline, is a direct function of a number of geological factors including the permeability and porosity of the strata. Natural pressure decline, however, may be partially controlled by producer selection of appropriate completion technology and operating procedures (Kuller and Cummings; U. S. Department of the Interior Officials). This control is of particular importance since resource recovery is generally a negative function of the rate of production (Davidson; Kuller and Cummings; McDonald, 1967). For the purpose of exposition, it is postulated that recovered reserves, R_o, may be expressed as:

$$(3) \qquad R_o = xR - \beta q_o e^{-a} - \gamma q_o ,$$

where β and γ are physical parameters related to geological conditions, $q_o e^{-a}$ the initial rate of production and q_o the installed capacity.[9] The cumulative output may then be written as:

$$(4) \qquad R_o = \int_0^T q_o e^{-at} dt,$$

where R_o equals $xR - \beta q_o e^{-a} - \gamma q_o$ from (3). For a given production time horizon, equation (4) states that cumulative output is equal to the magnitude of reserves which may be recovered at a given rate of production and installed capacity. In the subsequent analysis, this assumption is applied over all alternative bid systems.

Given R, a projection of the optimum level of investment or initial capacity "q_o", the production decline rate "a", and the production time horizon "T" must be made by a potential lessee before determining his bid. Economic theory indicates that this projection will be based upon the maximization of after-tax net present value revenue (Solow). For the purposes of leasing policy analysis, relevant cost components entering the after-tax net revenue calculation include investment cost, operating costs, royalties, the depletion allowance, the deduction for intangible drilling and development expenses, and other relevant tax provisions. After-tax net revenue taken over the anticipated production period and discounted, then equals the anticipated economic rent for the

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[9]Recovered reserves are expressed as a linear function of the rate of production and installed capacity since, for any given set of geological conditions which determine the values of β and α, the faster the rate of production and higher the installed capacity, the lower the volume of petroleum that is recovered. This results because reservoir pressure is inefficiently utilized at high rates of production and high capacity levels in relation to reservoir size. Although the form of this relationship has been the subject of substantial debate, the concept is often ignored in empirical studies (Davidson; Kuller and Cummings; McDonald, 1967). The specific functional form presented is utilized solely for exposition.

resource on a present value basis.

The theoretical framework can be expressed in the form of two basic relationships. The first defines the production time horizon limit as a function of physical, as well as economic, parameters. Theoretically, this limit is obtained when current expenses per unit equal revenue per unit of output. This relationship may be written as:

$$(5)\quad [(P_o + P_1t)(1-\lambda) - K_oe^{(\theta+a)t}] - \phi[(P_o + P_1t)(1-\lambda) -$$

$$z(P_o + P_1t)(1-\lambda) - K_oe^{(\theta+a)t}] = 0,$$

where P_o represents initial price per unit of production, P_1 the annual anticipated change in unit price, λ the royalty rate, ϕ the corporate income tax rate, z the percentage depletion allowance, K_o the initial operating costs per unit of capacity, and θ is a physical parameter related to initial reservoir conditions.[10] The first portion of the relationship represents net per unit revenue before taxes in time "t"; while the last part represents taxes payable per unit.

The second relationship maximizes after-tax net present value revenue subject to the production time horizon constraint represented by equation (5). For the purpose of exposition, this function is written in two parts. The first part, which represents net present value revenue before taxes (NPVBT) is expressed as:

$$(6)\quad NPVBT = \left[q_o \int_0^T (1-\lambda)(P_o + P_1t)e^{-(a+r)t}dt\right]$$

$$- \left[q_o \int_0^T K_oe^{[\theta-r]t}dt\right] - bq_o,$$

where q_o equals $axR/(1-e^{-aT} + \beta ae^{-a} + \gamma a)$ from equations (3) and (4), b represents investment cost per unit, and r is the continuous rate of

[10]Since total operating costs increase by the value θ through time, but remain constant in any time period regardless of the decline rate, unit costs increase at an exponential rate as production declines through time. This phenomena is due to equipment obsolescence (Arps; Davidson; U. S. Department of the Interior Officials). In notation form, total operating costs in any time, t, are expressed as $q_oK_oe^{\theta t}$. Thus, unit costs become: $q_oK_oe^{\theta t}/q_oe^{-at} = K_oe^{(\theta+a)t}$.

discount.[11] Thus, the first term on the right hand side of equation (6) represents the present value of gross revenues less royalty payments. The second term represents the present value of operating costs and the last term, investment.[12]

The present value of taxes payable (TAX) may be expressed as:[13]

$$\text{(7)} \quad TAX = q_o \phi \left\{ \int_C^T (1-\lambda)(P_o + P_1 t) e^{-(a+r)t} dt - \int_0^T K_o e^{[\theta - r]t} dt \right.$$

$$- z \int_0^T (1-\lambda)(P_o + P_1 t) e^{-(a+r)t} dt - \left[\sum_{i=1}^{n} \left[\frac{\frac{n-i}{(n^2+n)/2}}{(1+r_1)^i} \right] [yb(1-\alpha)] \right]$$

$$\left. - (1-y)b \right\} - \Omega q_o b,$$

where ϕ represents the tax rate, n the time horizon for depreciation, z the depletion rate, y the percent investment which is tangible, α the percent investment salvageable at n, r_1 the annual rate of discount, and Ω the investment tax credit rate. On the right hand side of equation (7), the third term represents the depletion allowance, followed by deductions for the present value of depreciation, intangible drilling expenses and the investment tax credit. When these per unit values are subtracted from the per unit present value revenue before taxes and the result multiplied by the present barrel

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[11]This equation form represents a simplified version of the form actually used in the subsequent analysis. A variable lag is incorporated in the actual model whereby investment ($q_o b$) is distributed over the lag period and production begins in the first year after the lag. The revenue and operating cost terms are discounted back from the beginning of production to the beginning of the lag. Investment costs are also discounted to the beginning of the lag. In this way, NPVBT is obtained for the time of the leasing decision.

[12]Equation (6) assumes that the unit investment cost is independent of the decline rate. However, per unit investment costs may be related to decline rates to the extent that producers attempt to control the level of the latter variable. This can be incorporated by modifying the investment cost term. For example, assuming that an exponential relationship exists between producer control of the decline rate and investment costs, the term $q_o b$ could be modified to $b = b_o e^{c(\Delta a)}$, where c is an engineering cost parameter.

[13]The sum of the years digits depreciation method is used. Tax treatment of bonuses is ignored. This omission is consistent with the industry decision process and does not substantially alter the empirical results (U. S. Department of the Interior Officials).

equivalent of production and the corporate income tax rate, total taxes payable can be calculated.[14] Equations (6) and (7) may then be combined and salvage value is added to obtain after-tax net present value.

For implementation, the framework may be restated such that after-tax net present value revenue is maximized subject to the cumulative production and time horizon constraints set forth in equations (4) and (5). The solution is then accomplished through the use of a computerized constrained search algorithm. This algorithm iterates the decline rate "a" over an exogenously specified range for the time horizon "T", subject to the upper limit time constraint specified in equation (5). Products of the solution are the optimum decline rate a^*, the optimum time horizon T^* (which may be less than the constraint calculated in equation (5)), the optimum initial capacity q_o, annual production, cumulative production, and the present value of after-tax revenue. By manipulation of the latter value, various bidding options can be simulated. For example, under a bonus bid system the expected bid plus royalties should equal present value of the economic rent given pure competition and the expected value of R. Under a royalty bid system, cumulative royalty payments equal the anticipated economic rent. Thus, after-tax net present value revenue can be constrained to zero with the royalty rate, λ, being determined.[15]

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[14]This form of the tax calculation is also a simplified version of the actual calculation to be used in the empirical analysis. A lag is incorporated representing the time between bidding and commencement of production. The initial capital investment is distributed over the lag period with present value tax savings calculated for the respective investment tax credits, expensed investments, and depreciation components occuring during the lag. Taxes during the production period are calculated according to the first three terms in equation (7) representing gross revenue minus royalty, operating costs, and depletion, plus depreciation during the production period. As mandated by statute, the depletion deduction is limited to 50 percent of net income before depletion. These taxes are discounted to the beginning of the lag period. Since the tax savings represent an opportunity cost to the government, the discounted value of tax savings is then subtracted from taxes paid to determine the net government tax revenue. In other words, tax savings are assumed to be applied against gross revenue and/or taxes (as the case may be) on other company operations. In essence, these excess tax write-offs are credited as additions to the after-tax net present value of the lease.

[15]It should be noted that, although the previous discussion refers primarily to oil reservoirs, the model can also be used to evaluate non-associated natural gas reservoirs. Knowledge of changes in the various parameters is all that is required. As natural gas shortages increase, this approach may become more common since producers will gain bargaining power over pipeline purchasers. Traditionally, however, decline rates and production time horizons have been set institutionally (due to contractural obligations for natural gas). Exogenous specification of these variables for model implementation, given reserves, determines initial installed capacity but the after-tax net present value optimization procedure is similar in form to that described above.

The previous discussion points out several issues which have obvious policy implications. First it is clear that the economic rent is directly related to the expected level of reserves. This factor is in turn a function of the schedule and location of lease sales. Second, the royalty rate, production rate restrictions (based on maximum efficient rate regulations), tax policy, and government policy affecting market prices are all important factors affecting petroleum production and investment decisions. Third, producer control over production decline rates and initial investment levels are important determinants of production profiles and government revenues under alternative resource allocation systems.

The Role of Uncertainty in Bidding Behavior: The conceptual framework outlined above does not consider uncertainty questions. Yet the relationship of the lease system to uncertainty evaluation by the industry may be a key in forecasting the implications of alternative lease systems (Leland). For example, contingency lease arrangements have been widely advocated primarily because it is assumed that these systems reduce the level of geological uncertainty borne by the industry.[16] That this can, in fact, take place may be demonstrated by the following example. Assuming all values are present values, first consider the expected payoff under a pure bonus bid system. This may be expressed as:

$$E(\hat{P}) = X \cdot E(\hat{R}) - B \qquad (8)$$

where X is a constant based upon economic variables including product prices and costs, $E(\hat{R})$ represents expected oil in place, and B, the bid. Thus, the variance of the payoff is:

$$Var(\hat{P}) = X^2 Var(\hat{R}) \qquad (9)$$

Under a pure royalty bid system, the expected payoff becomes:

$$E(\hat{P}) = X \cdot E(\hat{R}) - \lambda P \cdot E(\hat{R}) \qquad (10)$$

where λ is the royalty rate bid. The variance then becomes:

$$Var(\hat{P}) = (X-\lambda P)^2 \; Var(\hat{R}) \qquad (11)$$

Obviously, the variance is decreased, ceritus paribus, under the royalty bid system. However, in certain circumstances, the expected value alone may be an adequate basis for investment decision making. This situation arises when the decision is one of a large number of independent decisions

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[16] As used here, the term geological uncertainty refers to uncertainty with regard to the magnitude and location of reserves (Adelman, 1973, pp. 54-55).

and when the combined result of all decisions is of prime importance (Maass, pp. 137-158). The variance of the outcome becomes an important decision making variable only if these conditions do not hold. In either case, however, some assumption of the investors utility function is required.

Several approaches might be utilized to include questions of geological uncertainty in the decision framework.[17] First, it can be assumed that geological uncertainty is treated as actuarial in nature and that potential bidders have neither preference or aversion to it in a specific bid situation. In this case, use of the expected value is an appropriate adjustment for geological uncertainty in all cases. Second, it can be assumed that R will be valued at something less than its expected value. In this case, a risk adjusted discount rate may be utilized for empirical analysis (Maass, pp. 137-158). This rate may be expressed as:

$$(12) \qquad r_2 = \frac{1}{1+r+c\sigma}$$

where r_2 is the risk adjusted rate, r is the risk free discount rate, σ is the standard deviation of the payoff (which changes with the leasing system), and c is a constant related to the degree of risk preference or adversion. Given the assumptions stated above, the magnitude of the parameter c must obviously be subjectively determined.

Uncertainty with respect to future prices, as well as costs, may also be of importance in an analysis of alternative lease systems. For an ex ante implementation of the framework specified, exogenous projections of both parameters are required. Crude oil price projections may logically be based upon the assumptions that future foreign oil prices will determine domestic price levels.[18] However, the future level of these prices is subject to a substantial degree of uncertainty (this is also true for natural gas prices where regulation has hampered the workings of the market). Traditional analytical techniques provide little guidance for empirical investigation. As stated by Adelman:

> Supply and demand are as irrelevant to the future price as to the past ... The only thing that matters is whether the current market control, which explains the enormous margin ... (between development cost and price), will flourish or fade (1973, p. 253).

Since probability distributions of such phenomena are subjective in

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[17] It is assumed here that there is a known probability distribution of the size and location of original oil in place, R, such that the expected value and variance of R in any given area may be determined. For procedures useful for such determinations, see Allais, and Uhler and Bradley.

[18] This assumption stems from the concept of marginal cost pricing and the view that foreign crude is the major alternative source of supply and the supply source having the lowest production costs.

nature, sensitivity techniques may be appropriately utilized to incorporate this type of uncertainty into the analysis.

Conceptual Assumptions: The conceptual model presented contains three implicit assumptions. First, unitization is assumed so that externalities associated with the private exploration of common property resources may be ignored (McDonald, 1971). Second, user or opportunity costs associated with resource exhaustion are not incorporated. Such costs arise from the inherent nature of exhaustible resources in that each unit extracted reduces the quantity available in future periods. Consequently, for profit maximization, it may be theoretically argued that the value of future output sacrificed by a marginal increase in current extraction should be considered as a cost of production (Bradley; Davidson; Kuller and Cummings). However, there is evidence that firms tend to ignore such costs. At current discount rates, the present value of future revenue sacrificed due to increased extraction rates tends to be insignificant. Firms will, then base their investment and production decisions upon the resource available for extraction (Gordon). Finally, competitive bidding strategy considerations are not included in the analytical framework presented (Attanasi and Johnson; Brown).

Summary: Given the conceptual assumptions outlined and appropriate data on the exogenous variables, the analytical framework described above can be utilized to evaluate alternative OCS leasing methods and strategies. To partially test model validity, a series of ex post evaluations were conducted. Unpublished governmental estimates of potential oil reserves and development-operating costs, along with engineering estimates of physical parameters, for recent lease sale areas in the Gulf of Mexico were utilized. A complete analysis is not yet possible, since the production phase is in the early stages for most of these areas. All resulting bid estimates, however, were within 10 percent of actual values and other independent variables were reasonable and consistent with current experience in the Gulf (U. S. Department of the Interior Officials; U. S. Department of the Interior, 1970; U. S. Department of the Interior, 1972).[19]

Given this background, we can now turn to an ex ante application of the analytical framework. In the next chapter, alternative leasing methods will be evaluated under a variety of possible engineering and economic conditions.

[19] Both oil and natural gas reservoir areas were tested in this regard. It was assumed, based upon conversations with industry sources, that natural gas production was constrained by institutional time horizons, as described previously.

Chapter VI

An Evaluation of Alternative OCS Leasing Methods

At least one set of leasing policy alternatives may be common to all OCS activity, not just to the AOCS. These options concern the method of public land disposal via the lease system. A number of methods have been suggested as superior to the current cash bonus plus fixed royalty allocation approach. These include a royalty bid system, a bonus system with an increased royalty rate, a profit share system and an installment bonus system (Corrigan). In addition, changes in the current taxation system have been suggested (U. S. Congress, Senate, 1974).

This chapter discusses the application of the analytical framework previously specified to these questions. An attempt is made to show the conflicts and complementarities between possible social objectives as the leasing system is changed. From this analysis, a narrowed range of policy options will be derived for application to the geological and economic factors expected on the AOCS. However, it is possible that, upon evaluation, a preferred OCS allocation system may depend on specific factors relevant to a development area. Thus, the sensitivity of results shown below to critical parameters, will also be examined.

More specifically, the comparison of alternative leasing systems will consider:

1. The current system consisting of a cash bonus with a fixed royalty at 16 2/3 percent of value;
2. The current system with an increase in the fixed royalty to 40 percent of value;
3. A royalty system with no cash bonus (floating royalty rate based upon bid);
4. A profit share system with the rate set at 27 percent of net income (assuming the same taxation base as used presently for corporation income tax calculations); and
5. The previous options with and without the current 22 percent oil depletion allowance.

Other options could be specified but the ones indicated cover the range of suggestions currently being debated. Any additional alternatives are usually variations of those given.[20] However, the presence of uncertainty with

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[20] At first glance it may appear that an installment cash bonus system would differ fundamentally from those to be analyzed. However, such a system without a termination clause, is merely a variation on our current system. Given a competitive situation, capital availability and a state of information, the present value result should be identical. With a termination clause, uncertainty considerations would be affected and the result could differ. However, the latter case is difficult to analyze without a complex evaluation that considers reservoir size and cost relationships, as well as the specific terms under which a lease could be terminated.

respect to either geological or economic conditions may affect results under any of the scenarios discussed. To account for this possibility, analytical results will first be derived under the assumption of perfect certainty. Then, one means of incorporating uncertainty will be utilized to test the sensitivity of our results to this factor.

Common Implementation Assumptions: To insure consistency in the evaluation, all leasing options will be compared using a common set of assumptions. Also, the effects of exogenous factors likely to impact results will be tested for each option using similar limits. First, for oil reservoirs, producer control over initial investment levels and decline rates, within limits, is assumed. The degree of control over this rate is, however, a function of the specific geologic characteristics of individual hydrocarbon structures as well as the completion technology and operating procedures utilized to offset pressure decline (Kuller and Cummings; U. S. Department of the Interior Officials). The following evaluation will be conducted under two geological possibilities for the limit to control over the production decline rate. In all cases, lower bounds of 15 and 5 percent will be tested. No upper limit needs to be defined, since the lower bound becomes the critical economic constraint when attempting to maximize after-tax net present value.

Second, if geological conditions are held constant, the degree of producer control over the decline rate may be a function of the type and magnitude of production expenditures. The empirical relationship between this control and the relevant cost components of the framework specified previously is largely a matter of conjecture at this point.[21] For illustration purposes, two cases are assumed below. In the first instance, it is postulated that the relationship between control over decline rates and values of b and/or θ is practically insignificant. As an alternative, it is assumed that investment cost per unit of initial capacity takes on an exponential relationship with the decline rate (see footnote 12).

Third, it is assumed that adequate capital will be available to meet foreseeable increases in domestic petroleum development. In addition, short run constraints in the form of drilling and production equipment, and skilled manpower, are ignored. Institutional restrictions over the rate of production are also not considered in the case of oil reservoirs. Since such restrictions act to limit the rate of production in order to maximize recovery, their imposition on any given leasing system should be evaluated only after alternative systems have been analyzed for their effect on resource recovery without such a constraint. The possible implications of production restrictions may then be examined by comparing the analytical results of placing a limit on the annual production forthcoming under specific systems so that resource recovery is maximized (Davidson).

Fourth, the primary focus of the evaluation will be a comparison of the alternative systems when applied to oil reservoirs with associated natural gas. However, the model will also be applied to hypothetical non-associated natural gas reservoirs to test whether results would change under

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[21] This is primarily due to the obvious difficulty involved in determining the influence of geological phenomena upon the decline rate, along with the possible degree of control and the cost of that control.

such circumstances. As noted previously, however, several approaches can be utilized to carry out such a test. First, the model specified previously could be applied with the solution for production time, initial installed capacity and decline rate being endogenous. This assumes that no institutional constraints in the form of contractual agreements with pipeline purchases impact the development decision. Alternatively, such institutional constraints can be imposed upon the model. In other words, time horizons can be exogenously fixed and decline rates maintained at a very low level. For purposes of this analysis, both approaches will be examined. In the latter situation, an 18 year time horizon and a decline rate of .1 percent will be specified.

As a result of the assumptions given above, three possible scenarios may be obtained for any given oil reservoir. These include the following:

1. A 5 percent decline rate lower limit with fixed production costs based upon the characteristics associated with the reservoir in question;

2. A 15 percent decline rate lower limit with fixed production costs based upon the characteristics associated with the reservoir in question; and

3. A 5 percent decline rate lower limit with variable production costs based upon both the characteristics of the reservoir and the expenditures necessary for producer control of the decline rate below the natural geological limit.

For each set, the various leasing systems are analyzed by assuming that offshore acreage located in less than 600 feet of water and containing an estimated 1.17 billion barrels of recoverable oil in place is being offered for lease. It is assumed that lease development will take place over a five year period with production commencing in the sixth year at the initial installed capacity rate. Additional assumptions regarding product prices, production costs associated with such a reservoir, and physical parameters necessary for model implementation are listed in Table 9.

<u>Low Decline Rate, Fixed Production Costs:</u> For the first set of conditions, it is assumed that a low annual decline rate can be achieved on the basis of geological conditions and that producers can control this rate down to five percent. However, we assumed that production costs are fixed regardless of the control attempted by the producer. In addition, the initial installed capacity and the production time horizon may be varied by the industry in order to maximize after-tax net present value revenue. Uncertainty of an actuarial nature is assumed and a risk-free discount rate of 12 percent is used.

As shown in Table 10, an increase in the fixed royalty rate to 40 percent and a royalty bid system[22] both lead to a reduction in investment and initial

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[22]When left to competitive forces with no bonus bid required, the royalty rate expected as a bid under the assumptions used was 49 percent with no depletion allowance and 52 percent with the current 22 percent depletion allowance.

Table 9.--Initial Input Values for Leasing Policy Analysis

Parameter	Oil Value	Natural Gas Value
Production Cost/Unit Installed Capacity		
Investment, b	\$ 19.33	\$ 1.99
Operating, K_o	.55	.05
Price		
Initial, P	11.00	.52
Annual change, P_1	.00	.01
Tax Related		
Corporate income tax rate, ϕ	.48	.48
Investment tax credit rate, Ω	.07	.07
Depreciation period (years), n	15	15
Percent investment salvageable at n, α	10	10
Percent tangible investment, y	60	60
Percent depletion rate, z	0 and 22	0 and 22
Physical Parameters		
Reservoir condition, θ	.03	.03
Geological, β	1.5	1.5
Geological, γ	1	0

capacity installed as compared to the current system. At the same time, the production rate is reduced which results in an increase in recovery (or cumulative production), as well as a longer production time horizon. In other words, anticipated production is lower in the first few years but extends for a longer period than the present system.

Both royalty based resource allocation systems lead to a decrease in the bonus bid. However, the present value economic rent, which is traditionally defined as royalty plus bonus bid revenue, increases as the royalty rate is raised from 16 to 40 percent. In the cases presented, this is partially due to distortions inherent in the tax system as well as the specific tax assumptions used. Given the structure specified above, the bonus bid is defined to equal after-tax net present value revenue. Thus, the bonus bid is reduced by the calculated present value of tax payments. As the royalty rate is increased, taxes payable under the assumptions specified are reduced, and may, as in one example presented, fall to zero. Thus, the appropriate comparison under the alternative systems is the level of total government revenue. On the basis of this comparison, both royalty based resource allocation systems lead to a decrease in government revenue on a present value basis.

Under the assumptions presented, the implications of a profit share system clearly depend on the profit share base, the profit share rate and the

Table 10.--Comparison of Oil Model Results with Alternative Leasing and Tax Policies[a]

Variable	Units	Decline Rate Lower			
		With Depletion Allowance			
		Current Bonus Bid System	Increase In Fixed Royalty	Royalty Bid	Profit Share System
Royalty Rate, λ	%	16.67	40.0	.52	16.67
Profit Share Rate	%	--	--	--	27.0
Time Horizon, T^*	Years	12	16	26	12
Initial Capacity, q_o	MMBBL/yr.	102.18	87.05	68.92	102.18
Investment	$	1.98	1.68	1.33	1.98
Production Decline Rate, a	%	5	5	5	5
Total Recovery, R_o	MMBBL	922.03	958.74	1002.7	922.03
Royalty	$	.54	1.19	1.30	.54
Bonus Bid	$	.76	.31	.00	.54
Taxes Paid	$	.30	.04	.00	.52
Total Government Revenue	$	1.60	1.54	1.30	1.60

[a]All monetary values are present values (discounted at 12 percent) in billion dollars. MMBBL signifies million barrels. A development lag of 5 years was used for all alternatives.

Limit of 5 Percent

Without Depletion Allowance			
Current Bonus Bid System	Increase In Fixed Royalty	Royalty Bid	Profit Share System
16.67	40.0	.49	16.67
--	--	--	27.0
14	20	29	19
93.64	77.64	65.94	79.64
1.81	1.50	1.27	1.54
5	5	5	5
942.76	981.58	1010.0	976.74
.52	1.10	1.18	.47
.48	.12	.00	.12
.58	.22	.09	.89
1.58	1.44	1.27	1.48

corollary tax system. For example, a 27 percent rate on the current income tax base, produces results equivalent to the cash bonus approach. Removal of the depletion allowance from the base, however, causes initial capacity, investment and government revenue to fall relative to the cash bonus case. This result may be expected since, in the former case, an increase in the profit share rate leads to an increase in the effective depletion allowance per unit of production. Hence, there is an incentive to maintain investment levels.

In general, elimination of the current 22 percent depletion allowance results in a reduction in the initial capacity installed as well as total investment for all approaches. However, due to the alteration in the timing of production, as well as the increased taxes paid, total government revenue on a present value basis is decreased slightly over the with depletion system. These results tend to support the hypothesis that the depletion allowance results in higher investment levels and production rates. The analysis also suggests that the depletion allowance tends to swell economic rents (Davidson; Kahn). These rents can theoretically be captured with a bonus bidding system.

In all cases presented, an optimum is obtained by maximizing after-tax net present value revenue, subject to the constraints representing resource availability and the production time horizon. Thus, the industry may adjust the production decline rate, the initial capacity installed, and/or the production time horizon, as the bid and tax systems change in order to maximize net present value revenue. For example, initial capacity may fall, and the time horizon may increase, as occurred when the royalty rate was increased from 16 to 40 percent.

This result is contrary to previous studies which are based upon the assumption of a constant production profile (U. S. Department of the Interior Officials; VanMeurs). Given this assumption, any increase in the royalty rate reduces marginal revenue, and lower resource recoveries and government revenues may be obtained. This approach, however, fails to recognize flexibility in terms of the initial capacity installed, the production time horizon, as well as the production decline rate.

Of particular importance is the range within which the production rate can be varied by petroleum producers. If that range is limited by physical conditions or institutional factors such as maximum efficient rate (MER) restrictions, net present value revenue would be altered for all lease systems analyzed. Thus, the absolute level of government revenue cannot be specified a priori since it depends on geophysical-institutional-economic interactions. One example of this issue will be presented in the following section.

Finally, the impact of all bid systems upon government revenue is subject to several qualifications. First, for each alternative it is assumed that a 1.17 billion barrel expected reserve will be discovered. If it turns out, ex post, that this value was greater than that actually discovered, royalty collections and/or profit shares would obviously be reduced whereas the bonus bid collected would remain unaltered. In addition, if actual reserves were less than expected, the field may be abandoned under a royalty bid system. However, if the value is less than discovered, royalty revenues and/or profit shares would be increased. The final result with respect to government revenue depends on the level of actual reserves discovered, the relationship of the lease system to uncertainty evaluation by the industry,[23] and the interaction between reduced revenues and the tax-royalty structure. Second, lease profitability (and consequently, development feasibility) depends both upon the level of the royalty rate and product prices. For example, under a 40 percent fixed royalty system and a $5.00 per barrel oil price, no bids would be generated for the acreage offered under the assumptions discussed previously. However, a bonus bid would, at current royalty rates, be offered. Inefficiencies of this type are not associated with a pure royalty bid system.

High Decline Rate, Fixed Production Costs: For the second set of conditions, we assume that geophysical factors prohibit a low decline rate. Thus, producer control over this rate is further constrained. All other conditions are similar to the previous case. Table 11 details the results. In general, the impacts are similar to those discussed above. However, reduced control over the decline rate sharply reduces the differences between alternative systems and between the same system under alternative depletion allowance assumptions. In certain circumstances, in fact, the differences may be totally eliminated due to the reduced production times. Moreover, the cases presented demonstrate the possibility of generating no bids under bid systems with fixed payout requirements (fixed royalty and profit share). In the profit share case, the tax base used, in conjunction with the rate, resulted in income taxes that were greater than before-tax net present value (without the depletion allowance.) This is due to the current tax code definition for taxable income and the differential tax rates used under this system when accounting for tangible and intangible investment. A floating (or bid) profit share rate would mitigate this circumstance, as would a different definition of the tax base (one which utilized after-tax profits as its base).

Variable Decline Rate, Variable Production Costs: The third set of conditions simulated by the model assumed a variable decline rate from 5 to 15 percent, but a producer cost in achieving any value below 15 percent. Previous cases assumed unit development costs independent of the decline rate. Thus, after-tax net present value was maximized at the lower bound of the decline rate for each lease system. In this case, a functional relationship between a and b was specified (see footnote 12)[24] and the impact upon investment levels, production rates and government revenue ascertained. The results of model runs are presented in Table 12.

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[23] For example, under a royalty system, a bidder may offer the full value of the estimated resource because relatively little cost is entailed in the event of a dry hole. This fact can also lead to speculative behavior on the bidder's part. On the other hand, the bonus bidder may discount his bid since the risk is higher.

[24] The engineering constant "c" specified in this exponential relationship ($b = b_o e^{c(\Delta a)}$) was set at a value of 4.

Table 11.--Comparison of Oil Model Results With Alternative Leasing and Tax Policies[a]

Variable	Units	Decline Rate Lower			
		With Depletion Allowance			
		Current Bonus Bid System	Increase In Fixed Royalty	Royalty Bid	Profit Share System
Royalty Rate, λ	%	16.67	40.0	27.0	16.67
Profit Share Rate	%	--	--	--	27.0
Time Horizon, T^*	Years	14		15	14
Initial Capacity, q_o	MMBBL/yr.	143.71		141.73	143.71
Investment	$	2.78		2.74	2.78
Production Decline Rate, a	%	15		15	15
Total Recovery, R_o	MMBBL	840.75		845.29	840.75
Royalty	$	.54		.87	.54
Bonus Bid	$	.35		.00	.29
Taxes Paid	$	.00		.00	.06
Total Government Revenue	$	.89	No Bid	.87	.89

[a]All monetary values are present values (discounted at 12 percent) in billion dollars. MMBBL signifies million barrels. A development lag of 5 years was used for all alternatives.

Limit of 15 Percent

Without Depletion Allowance			
Current Bonus Bid System	Increase in Fixed Royalty	Royalty Bid	Profit Share System
16.67	40.0	21.0	16.67
--	--	--	27.0
15		15	
141.73		141.15	
2.74		2.73	
15		15	
845.29		846.63	
.54		.67	
.07		.00	
.27		.20	
.88	No Bid	.87	No Bid

Table 12.--Comparison of Oil Model Results With Alternative Leasing and Tax Policies[a]

Variable	Unit	Decline Rate Lower Limit of 5 Percent and With Depletion Allowance			
		Current Bonus Bid System	Increase In Fixed Royalty	Royalty Bid	Profit Share System
Royalty Rate,	%	16.67	40.0	32.0	16.67
Profit Share Rate	%	--	--	--	27.0
Time Horizon, T^*	Years	17		32	17
Initial Capacity, q_o	MMBBL/yr.	84.30		63.63	84.30
Investment	$	2.43		1.83	2.43
Cost Per Unit of Installed Capacity[c]	$	28.84		28.84	28.84
Production Decline Rate, a	%	5.0		5.0	5.0
Total Recovery, R_o	MMBBL	965.41		1015.6	965.41
Royalty	$	.49		.79	.49
Bonus Bid	$	.40		.00	.30
Taxes Paid	$	.05		.00	.15
Total Government Revenue	$	.94	No bid	.79	.94

[a]Monetary values are present values (discounted at 12 percent) in billion dollars. A development lag of 5 years was used for all alternatives.

[b]See footnote 12 of main text.

[c]Dollars per unit of initial (peak) annual capacity.

Variable Production Costs Based On Decline Rate[b]			
Without Depletion Allowance			
Current Bonus Bid System	Increase in Fixed Royalty	Royalty Bid	Profit Share System
16.67	40.0	28.0	16.67
--	--	--	27.0
22		32	
74.19		63.63	
2.14		1.83	
28.84		28.84	
5.0		5.0	
989.94		1015.6	
.44		.65	
.15		.00	
.30		.14	
.89	No Bid	.79	No Bid

As shown, if there is a private cost entailed in order to gain control over the rate of decline in production, producers tend to accept the increased per unit cost but avoid the full economic penalty by reducing their installed capacity and extending production time horizons.[25] As a result of the low decline rate and the longer production time, cumulative production is increased. However, since production profiles are shifted toward the future, government revenue on a present value basis is reduced. As occurred previously, the fixed payout options tested had a tendency to produce no bids under the assumptions specified. Given the required costs of production and/or income tax base, after-tax net present value would have been negative for those options. Elimination of the depletion allowance, either slightly reduced or did not affect government revenue and annual production. This analysis, then, demonstrates that the impact of alternative public policies depends upon the specific engineering-economic assumptions utilized.

Summary and Conclusions: The previous evaluation has pointed out the trade-offs implicit in various leasing strategies and the geophysical-institutional-economic interactions which must be accounted for in making public resource management decisions. The trade-offs between the objectives of government revenue maximization, cumulative resource recovery, and the timing of production have been demonstrated for various lease systems. Table 13 compares the general effects of alternative bidding and tax policies to the current cash bonus system under conditions of actuarial certainty.

In general, we have shown that contingency lease arrangements tend to shift production profiles toward the future with an associated increase in resource recovery and lower annual production rates. As this occurs, public revenues may be reduced. However, it is clear that a profit share system could be designed which would closely approximate annual production and total recovery from other systems by proper manipulation of the profit share rate and the associated income base. The impact of the various lease systems upon government revenue is subject to several other qualifications including the assumptions with regard to uncertainty evaluation by the industry and the degree of producer control over production rates. Moreover, the level of government revenue under all systems depends upon the geophysical factors associated with individual reservoirs. Elimination of the oil depletion allowance under any lease system would tend to reduce annual production and total government revenue, but increase total recovery.[26]

The impact of alternative lease systems under uncertainty can be explored by the technique of adding a risk factor to the discount rate. Table 14 shows the effect of varying the discount rate for the cash bonus approach from 12 to 18 percent. If it is hypothesized that a zero risk premium is associated with the profit share system, these results can be

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[25] Given a different lower limit to the production decline rate or a different cost function, this phenomena could change.

[26] Application of the model to natural gas reserves did not materially change any of the conclusions stipulated.

Table 13.--Alternative Leasing Systems Compared to Current Cash Bonus

Variable	Increase in Fixed Royalty (50%)	Royalty Bid	Profit Share (27%)	Elimination of Depletion Allowance
Investment	-	-	-	-
Production Time	+	+	+	+
Annual Production	-	-	-	-
Total Recovery	+	+	+	+
Government Revenue	-	-	N.C.[1]	-[2]

[1]There appeared to be little or no change in government revenue under the profit share system with the numbers used in this analysis. However, a profit share bidding approach with a variable profit share was not analyzed. This analysis will be conducted in future research.

[2]There was a very slight loss in total government revenue with elimination of the depletion allowance. In most cases, the difference would not be statistically significant.

compared with those for profit sharing in Table 11.[27] As shown, both government revenues and resource recoveries surpass the cash bonus system when the discount rate reaches or exceeds 14 percent. Production time horizons, initial installed capacity and, consequently, annual production remain lower than the profit share case, as defined, up to 18 percent discount. As a result, definite trade-offs between the multiple public objectives may be implicit in deciding between a cash bonus and a profit share bid system. Further research needs to be directed at these trade-offs and the implication of variations in a profit share system for them. The income tax base, the question of fixed or floating profit share rates, the impact on entry and competition, and the administrative costs all need to be explored. This will be one subject of our continuing research in this area.

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[27]Given the negative conclusions reported above for the royalty systems, we elected not to make such a comparison for a royalty approach. If this were carried out, a lower risk premium than that used for the cash bonus, but higher than zero, would be appropriate.

Table 14.--Cash Bonus Impacts Under Alternative Risk Adjusted Discount Rates[a]

Variable	Unit	Decline Rate Lower Limit of 5 Percent and Fixed Production Costs							
		Bonus Bid System With Depletion Allowance				Bonus Bid System Without Depletion Allowance			
		12% Discount Rate	14% Discount Rate	16% Discount Rate	18% Discount Rate	12% Discount Rate	14% Discount Rate	16% Discount Rate	18% Discount Rate
Royalty Rate, λ	%	16.67	16.67	16.67	16.67	16.67	16.67	16.67	16.67
Time Horizon, T^*	Years	12	12	13	13	14	14	15	18
Initial Capacity, q_o	MMBBL/yr.	102.18	102.18	97.61	97.61	93.64	93.64	90.14	81.84
Investment	$	1.98	1.98	1.89	1.89	1.81	1.81	1.74	1.58
Production Decline Rate, a	%	5	5	5	5	5	5	5	5
Total Recovery, R_o	MMBBL	922.03	922.03	933.10	933.10	942.76	942.76	951.24	971.38
Royalty	$	.54	.46	.38	.32	.52	.44	.36	.28
Bonus Bid	$	.76	.55	.37	.24	.48	.32	.18	.07
Taxes Paid	$	.30	.20	.13	.07	.58	.44	.32	.22
Total Government Revenue	$	1.60	1.21	.88	.63	1.58	1.20	.86	.57

[a] A five year development lag is assumed.

Given the current energy situation, this analysis does show an advantage for the present cash bonus plus royalty leasing system. Production profiles, from a given leased area, are substantially shorter than under an all royalty approach and may be shorter than under profit sharing. Total recovery, while somewhat lower, is not greatly reduced in terms of present barrel equivalents. As a result, the present value of total government revenue tends to be maximized under the cash bonus system. As indicated above, however, this may not hold in all situations. Providing that it does not result in the erection of undue barriers to entry (because of high capital requirements and the uncertainty involved in petroleum exploration), the current cash bonus system appears as an appropriate public vehicle for capturing economic rent and maximizing annual production from newly discovered petroleum reserves on federal lands. Elimination of the percentage depletion allowance would not greatly affect this conclusion and would, in addition, slightly increase resource recovery.

Given this background, the next chapter will examine the economics of the AOCS in more detail. In view of the current institutional setting and the findings detailed above, we will assume that the current leasing system is retained but that the percentage depletion allowance is eliminated for AOCS acreage disposal. Profit sharing arrangements do, however, appear to warrant future study.

Chapter VII

Empirical Results of the AOCS Evaluation

We are now in a position to evaluate alternative leasing policies for the AOCS. This will require the merging of geological and production cost data, presented in Chapters II and III, with the model formulated in Chapter V. Then, using the policy conclusions drawn from Section II and Chapter VI, appropriate alternatives for the AOCS can be tested. These alternatives involve the components of a long-range leasing program. Particularly important factors affecting the outcome of the leasing program are the following:

- Petroleum pooling assumptions - Since little is known about regional reserve potential, reserve locations must be assumed.

- Sale scale - How many acres are offered annually?

- Sale location - Where and in what order is the acreage to be leased?

- Production lag times - There is a lag between leasing and commencement of production especially in the early years of developing an area. The length of this lag affects the timing of production, onshore effects and the present value of producer income and government revenue.

The leasing model for an individual lease sale discussed in Chapter VI was expanded to allow multiple sales each year and over a number of years. The model combines the results of yearly sales into a matrix providing annual or annualized values for installed capacity, investment, production, royalty, taxes, and bonus bids. Total production and the present value of royalty, taxes, and bonus bids is also computed. This expanded model was used with the AOCS reserve and cost data to depict a possible leasing schedule.

<u>A Hypothetical Leasing Program</u>: Using the data presented in Chapter II, there are over 75 million acres offshore on the Atlantic shelf and slope. Of this, about 49 million acres are in less than 1500 feet of water and thus suitable for commercial development with current technology. In designing a probable, but hypothetical, leasing program for the AOCS, we assumed that two-thirds of the acreage available for commercial development would be nominated for lease sales by the existing nomination process. Thus, 33 million acres would be offered over the life of the program. Historically, about half the acreage nominated and offered for sale is actually leased by producers.

We further assumed that all the potential AOCS oil and natural gas reserves are located under the acreage actually offered and purchased for development. These assumptions, however, are not crucial to the analysis. On the other hand, the magnitude of estimated reserves is central to the evaluation. For purposes of exposition, we will use the median resource estimates from Chapter II (Table 2). These values can be easily varied to test other forecasts.

Alternative annual sale scales were considered for our hypothetical leasing program. Because of the low level of expected reserves relative to domestic demand, a three million acre annual offering was selected for analysis. This would permit rapid development of the reserves present yet be physically and institutionally feasible. An annual sale of this size results in an eleven year leasing program for the AOCS under our initial assumption of 33 million acres to be offered. Obviously, any alternative rate could be evaluated, but the rate chosen appears most likely at this writing.

The order in which specific areas would be leased was decided on the basis of reserve potential and expected economic return. From the reserve estimates in Chapter II, each sub-region was ranked according to the barrels of oil per acre. Using a lease offering of three million acres per year, sub-regions were leased in order of the expected petroleum concentration derived above subject to an economic return constraint. In some cases the profitability constraint caused changes in the lease ordering because of expected differences in production costs. For example, regions 11-13 in the Baltimore Canyon area would likely be leased before the Georges Bank because of the significantly lower investment costs. Similarly, potentially productive areas on the continental slope would be leased last because of the significantly higher investment costs. A complete leasing schedule, based on these criteria, for the eleven years is given in Table 15. The table lists, by year of disposal, the lease area and for each area the oil and associated gas reserves (in terms of oil), non-associated gas and natural gas liquids reserves (in terms of gas), oil reserves per acre, projected oil investment costs, and projected non-associated gas investment costs.

For nonspecific broad areas such as Other North Atlantic shelf, it was assumed that the petroleum was equally divided over the area offered for lease. This assumption is important only in so far as it affects the timing of sales and location of reserves. Alternative assumptions could easily be employed. For the nonspecific Atlantic shelf and slope areas north of 33°, it was assumed that one-half would be considered North Atlantic and one-half Mid-Atlantic for investment cost purposes. The Mid-Atlantic areas are leased first because of greater expected economic return.

The other factor affecting a projected lease program is expected production lags after the lease is granted. In the Gulf of Mexico, a three year production lag is common. However, since there has been no drilling or facility development off the U. S. Atlantic coast, the initial production lags are expected to be higher. A five year production lag was assumed for sales during the first year of leasing and a four year lag for those in the second. All future sales were assumed to have a three year production lag. The initial lags assume leasing begins no sooner than 1976. Hence, the earliest production would be expected in 1981.

Issues of sale scale, location and anticipated production lags raise a number of other interesting and important aspects related to a leasing program. Examples include the effects of manpower and equipment constraints or the implication of obtaining improved (public) geologic information prior to government leasing. These issues are not analyzed here, but will be examined in subsequent research. In not treating with these and other related issues, we are not denying their importance; quite the opposite, for they deserve a full analytical treatment which was

Table 15.--Hypothetical Leasing Schedule for the AOCS

Program Year	Area and Region Number[a]	Acres (million)	Potential Oil Reserves[b] (bil. bbl.)
1	Baltimore Canyon Proper (8,9,10)	2.35	1.12
	Baltimore Canyon Area (14)	.56	.19
	Baltimore Canyon Area (11,12,13)	.10	.03
	TOTAL	3.00	1.34
2	Baltimore Canyon Area (11,12,13)	2.04	.52
	Georges Bank Proper (1,2,3)	.97	.28
	TOTAL	3.00	.80
3	Georges Bank Proper (1,2,3)	.91	.27
	Other North Atlantic (16)	2.09	.38
	TOTAL	3.00	.65
4	Other North Atlantic (16)	3.00	.55
5	Other North Atlantic (16)	2.59	.48
	Other North Atlantic (16)	.41	.07
	TOTAL	3.00	.55
6	Other North Atlantic (16)	3.00	.55
7	Other North Atlantic (16)	3.00	.55
8	Other North Atlantic (16)	1.27	.24
	Georges Bank Area (4,5,6)	1.73	.25
	TOTAL	3.00	.49
9	Georges Bank Area (4,5,6)	2.03	.30
	South Atlantic Shelf (18)	.97	.04
	TOTAL	3.00	.34
10	South Atlantic Shelf (18)	3.00	.13
11	South Atlantic Shelf (18)	1.83	.08
	Baltimore Canyon Slope (15)	.04	.02
	Georges Bank Slope (7)	.05	.02
	Other North Atlantic Slope (17)	.38	.13
	South Atlantic Slope (19)	.46	.06
	TOTAL	2.76	.31

[a]See Table 2, Chapter II for more detail.

[b]Associated natural gas and natural gas liquids are converted to equivalent barrels of oil on a revenue basis (see pages 17-18). Because of the rising price of natural gas, the conversion is somewhat in error in later years, but the difference is insignificant.

[c]Natural gas liquids are converted to equivalent cubic feet of natural gas on a revenue basis (see pages 17-18). Because of the rising price of natural gas, the conversion is somewhat in error in later years (in the opposite direction of the oil conversion), but the difference is insignificant.

Potential Non-Assoc. Nat'l. Gas Reserves[c] (TCF)	Potential Oil/Acre (1000 bbl.)	Oil Invest-ment Cost ($/yearly bbl.)	Gas Invest-ment Cost ($/yearly MCF)
9.21	.47	$ 19.33	$ 1.99
1.63	.34	19.33	1.99
.20	.26	19.33	1.99
11.04			
4.24	.26	19.33	1.99
2.28	.29	27.60	2.83
6.42			
2.16	.29	27.60	2.83
3.12	.18	19.33	1.99
5.28			
4.48	.18	19.33	1.99
3.88	.18	19.33	1.99
.60	.18	27.60	2.83
4.48			
4.48	.18	27.60	2.83
4.48	.18	27.60	2.83
1.92	.18	27.60	2.83
2.04	.15	27.60	2.83
3.96			
2.40	.15	27.60	2.83
.35	.04	10.71	1.10
2.75			
1.09	.04	10.71	1.10
.67	.04	10.71	1.10
.18	.50	37.78	3.88
.18	.41	56.18	5.77
1.07	.34	37.78	3.88
.53	.13	19.38	1.99
2.63			

beyond the scope of this analysis, but which will be possible at a later date.

Empirical Results: On the basis of the hypothetical leasing program described above, empirical results were derived for three separate regions in the Atlantic. These results were then summarized for the entire AOCS. All lease impacts were derived based on a cash bonus lease system with no depletion allowance and a 16 2/3 percent fixed royalty. The initial lease sales for the eleven year program were assumed to commence in 1976, although a later start would merely have the effect of postponing the various impacts by the period of delay. In all cases tested, a lower limit to the decline rate of 5 percent was used and fixed production costs were assumed (see Chapter III).

Results are presented separately for oil and associated natural gas, for non-associated natural gas and natural gas liquids, and for the combined hydrocarbon reserves. Table 16 shows the pertinent results for the former category separated for the Middle, North and South Atlantic regions. The Mid-Atlantic would be the most productive region, producing a cumulative total of 2.7 billion barrels, with most of the area leased early in the program. On the other hand, the South Atlantic would produce very little oil or associated gas, at current prices and production costs, because most reserves are forecast to be in water deeper than 1500 feet.

Table 17 contains the leasing results for non-associated natural gas and natural gas liquids for each region. As explained previously, a production time horizon of 18 years and a decline rate of .1 percent was assumed for this portion of the resource because of contractual obligations. Note that with a 1976 natural gas price of $.52 per Mcf and a $.01 annual increase, no bids are obtained for any North Atlantic gas regions prior to 1981. A minimum gas price of $.59 per Mcf is required for production because of investment costs which are higher than those for the Mid-Atlantic. High costs also appear to limit development on the Mid- and North Atlantic slope as late as 1986. Non-associated natural gas production from these areas is shown as zero in Table 17 because the extent of their existence in areas with oil prospects is not known. To the extent that the areas are leased for oil prospects, the high non-associated natural gas development costs would probably result in a postponement of any non-associated gas production. To the extent that these areas are viewed as exclusively natural gas prospects, the high cost would lead to a lack of bids in the year offered and, thus, probably result in a revised leasing schedule and a further postponement in production. The extent of such schedule changes is unknown with present information. Over five TCF of natural gas may be affected by this consideration in the North Atlantic and almost 1.5 TCF on the slope (in less than 1500 feet of water). For purposes of analytical consistency, we have assumed the leasing program would not be modified (hence, the zero values). However, in the real world, these circumstances would probably result in some modifications to the lease schedule or to regulated prices, or both. Further exploration of this question would require more herioc assumptions than are warranted here.[28]

Table 18 summarizes the hydrocarbon recovery and revenue results for oil, natural gas and natural gas liquids in the three AOCS regions. Overall exploration, development and production impacts, on an annual basis, are shown in Table 19. As indicated, production would begin in 1981, given the procedures, assumptions and data inputs described above, and would peak for oil in 1987 and for natural gas in 1989. On the other hand, production of oil would cease in 2019 and for natural gas in 2006. Total government revenue would be at a maximum in 1986. Almost $29 billion of revenue (undiscounted) would result for the government over the 43 year production period. At the same time, private sector investment would total almost $16.5 billion.

Table 20 displays the components of government revenue, when discounted to 1976 at 12 percent, for the three regions. In addition, production figures summed over the life of the production period and segregated by type of hydrocarbon are given. On a present value basis, government revenue totals almost $8.5 billion from a total production that depleted from 80 percent (oil) to almost 87 percent (natural gas) of the estimated recoverable reserves (xR).

The sensitivity of the analytical results to the assumptions and procedures used must be remembered when reviewing the tabled values. Changes in one or more of the important input values could seriously affect the results reported. In general, a change in reserves would have a direct and proportional relationship to production and government revenue. Factors like market price, production costs, sale scale, and order of sale locations, however, would not generally have a proportional effect and would likely change production profiles.

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[28]It is interesting to note that when the model is run with 1976 natural gas prices of $.82 per Mcf, all areas received bids except the Georges Bank area slope in year eleven (as in the oil results). Total gas production also rose from 44.7 TCF to 51 TCF.

Table 16.--AOCS Leasing Results by Region and Year for Oil and Associated Natural Gas

Year	Year No.	Area and Region Number[a]	Oil and Associated Natural Gas Reserves[b] (bil. bbl.)	Installed Capacity[c] (mil. bbl.)	
					Mid-
1976	1	Baltimore Canyon (8,9,10,11,12,13,14)	1.34	107.24	
1977	2	Baltimore Canyon (11,12,13)	.52	43.38	
1978	3	Other North Atlantic (16)	.38	31.70	
1979	4	Other North Atlantic (16)	.55	45.89	
1980	5	Other North Atlantic (16)	.48	40.05	
1986	11	Baltimore Canyon Slope (15) and Other North Atlantic Slope (17)	.15	8.25	
					North
1977	2	Georges Bank (1,2,3)	.28	19.06	
1978	3	Georges Bank (1,2,3)	.27	19.45	
1980	5	Other North Atlantic (16)	.07	5.04	
1981	6	Other North Atlantic (16)	.55	39.63	
1982	7	Other North Atlantic (16)	.55	39.63	
1983	8	Georges Bank (4,5,6) and Other North Atlantic (16)	.49	35.31	
1984	9	Georges Bank (4,5,6)	.30	21.62	
1986	11	Georges Bank Slope (7)	.02	0.0	
					South
1984	9	South Atlantic Shelf (18)	.04	4.13	
1985	10	South Atlantic Shelf (18)	.13	13.44	
1986	11	South Atlantic Shelf (18)	.08	8.27	
1986	11	South Atlantic Slope (19)	.06	5.01	

[a]See Table 2, Chapter II for more detail.

[b]Associated natural gas and natural gas liquids are converted to equivalent Because of the rising price of natural gas, the conversion is somewhat in error in later

[c]Initial capacity installed at end of development time lag.

[d]All values pertinent to a given lease sale are present valued, at a 12 percent The values given cannot be summed because they are present valued to different years.

		Present Value to Lease Year[d]			
Prod. Time Horizon (years)	Total Recovery (bil. bbl.)	Royalty (bil.$)	Taxes (bil.$)	Bonus Bid (bil.$)	Total Govt. Revenue (bil.$)
<u>Atlantic</u>					
14	1.08	.60	.66	.55	1.81
13	.41	.26	.31	.26	.83
13	.30	.22	.26	.23	.71
13	.44	.31	.38	.34	1.03
13	.38	.27	.33	.29	.89
31	.13	.06	.03	.00	.09
<u>Atlantic</u>					
19	.23	.13	.10	.07	.30
17	.22	.14	.12	.09	.35
17	.06	.04	.03	.02	.09
17	.45	.29	.25	.18	.72
17	.45	.29	.25	.18	.72
17	.40	.26	.22	.16	.64
17	.25	.16	.14	.10	.40
0	.00	.00	.00	.00	.00
<u>Atlantic</u>					
9	.03	.02	.04	.04	.10
9	.10	.08	.13	.13	.34
9	.06	.05	.08	.08	.21
13	.05	.03	.04	.04	.11

barrels of oil on a revenue basis (see pages 17-18).
years, but the difference is insignificant.

discount rate, to the year of that sale.

Table 17.--AOCS Leasing Results by Region and Year for Non-Associated Natural Gas and

Year	Year No.	Area and Region Number[a]	Non-Associated Gas and Natural Gas Liquid Reserves[b] (TCF)	Installed Capacity[c] (mil.MCF)
				Mid-
1976	1	Baltimore Canyon (8,9,10,11,12,13,14)	11.04	618.87
1977	2	Baltimore Canyon (11,12,13)	4.24	237.68
1978	3	Other North Atlantic (16)	3.12	174.90
1979	4	Other North Atlantic (16)	4.48	251.14
1980	5	Other North Atlantic (16)	3.88	217.50
1986	11	Baltimore Canyon Slope (15) and Other North Atlantic Slope (17)	1.25	0.0
				North
1977	2	Georges Bank (1,2,3)	2.28	0.0
1978	3	Georges Bank (1,2,3)	2.16	0.0
1980	5	Other North Atlantic (16)	.60	0.0
1981	6	Other North Atlantic (16)	4.48	251.14
1982	7	Other North Atlantic (16)	4.48	251.14
1983	8	Georges Bank (4,5,6) and Other North Atlantic (16)	3.96	221.99
1984	9	Georges Bank (4,5,6)	2.40	134.54
1986	11	Georges Bank Slope (7)	.18	0.0
				South
1984	9	South Atlantic Shelf (18)	.35	19.62
1985	10	South Atlantic Shelf (18)	1.09	61.10
1986	11	South Atlantic Shelf (18)	.67	37.56
1986	11	South Atlantic Slope (19)	.53	29.71

[a]See Table 2, Chapter II for more detail.

[b]Natural gas liquids are converted to equivalent cubic feet of natural gas on a
rising price of natural gas, the conversion is somewhat in error in later years (in
but the difference is insignificant.

[c]Initial capacity installed at end of development time lag.

[d]All values pertinent to a given lease sale are present valued, at a 12 percent
The values given cannot be summed because they are present valued to different years.
in all cases.

Natural Gas Liquids

Total Recovery (TCF)	Present Value to Lease Year[d]			
	Royalty (bil.$)	Taxes (bil.$)	Bonus Bid (bil.$)	Total Govt. Revenue (bil.$)
Atlantic				
11.04	.27	.18	.10	.55
4.24	.11	.09	.06	.26
3.12	.09	.08	.06	.23
4.48	.14	.12	.09	.35
3.88	.12	.11	.08	.31
0.0	.00	.00	.00	.00
Atlantic				
0.0	.00	.00	.00	.00
0.0	.00	.00	.00	.00
0.0	.00	.00	.00	.00
4.48	.14	.06	.00	.20
4.48	.14	.06	.01	.21
3.96	.13	.06	.01	.20
2.40	.08	.04	.01	.13
0.0	.00	.00	.00	.00
Atlantic				
.35	.01	.02	.02	.05
1.09	.04	.06	.05	.15
.67	.02	.03	.03	.08
.53	.02	.02	.01	.05

revenue basis (see pages 17-18). Because of the
the opposite direction of the oil conversion),

discount rate, to the year of that sale.
A production time horizon of 18 years is assumed

Table 18.--Overall AOCS Leasing Results by Region and Year

Year	Year No.	Area and Region Number[a]	Oil Recovery[b] (bil. bbl.)	Non-Associated Natural Gas Recovery[c] (TCF)
				Mid-
1976	1	Baltimore Canyon (8,9,10,11,12,13,14)	1.08	11.04
1977	2	Baltimore Canyon (11,12,13)	.41	4.24
1978	3	Other North Atlantic (16)	.30	3.12
1979	4	Other North Atlantic (16)	.44	4.48
1980	5	Other North Atlantic (16)	.38	3.88
1986	11	Baltimore Canyon Slope (15) and Other North Atlantic Slope (17)	.13	0.0
			2.74	26.76
				North
1977	2	Georges Bank (1,2,3)	.23	0.0
1978	3	Georges Bank (1,2,3)	.22	0.0
1980	5	Other North Atlantic (16)	.06	0.0
1981	6	Other North Atlantic (16)	.45	4.48
1982	7	Other North Atlantic (16)	.45	4.48
1983	8	Georges Bank (4,5,6) and Other North Atlantic (16)	.40	3.96
1984	9	Georges Bank (4,5,6)	.25	2.40
1986	11	Georges Bank Slope (7)	.00	0.0
			2.06	15.32
				South
1984	9	South Atlantic Shelf (18)	.03	.35
1985	10	South Atlantic Shelf (18)	.10	1.09
1986	11	South Atlantic Shelf (18)	.06	.67
1986	11	South Atlantic Slope (19)	.05	.53
			.24	2.64

Source: Tables 17 and 18.

[a]See Table 2, Chapter II for more detail.

[b]Associated natural gas and natural gas liquids are converted to equivalent natural gas, the conversion is somewhat in error in later years, but the difference is

[c]Natural gas liquids are converted to equivalent cubic feet of natural gas on a the conversion is somewhat in error in later years (in the opposite direction of the oil

[d]All values pertinent to a given lease sale are present valued, at a 12 percent because they are present valued to different years.

	Present Value to Lease Year[d]			
	Royalty (bil.$)	Taxes (bil.$)	Bonus Bid (bil.$)	Total Govt. Revenue (bil.$)
Atlantic				
	.86	.85	.65	2.36
	.38	.40	.32	1.10
	.31	.35	.29	.95
	.45	.50	.42	1.37
	.39	.44	.37	1.20
	.06	.03	.00	.09
Atlantic				
	.13	.10	.07	.30
	.14	.12	.09	.35
	.04	.03	.02	.09
	.43	.31	.18	.92
	.43	.32	.18	.93
	.39	.28	.17	.84
	.24	.18	.11	.53
	.00	.00	.00	.00
Atlantic				
	.03	.06	.06	.15
	.12	.18	.18	.48
	.07	.11	.11	.29
	.05	.06	.05	.16

barrels of oil on a revenue basis (see pages 17-18). Because of the rising price of insignificant.

revenue basis (see pages 17-18). Because of the rising price of natural gas, conversion), but the difference is insignificant.

discount rate, to the year of that sale. The values given cannot be summed

Table 19.--Overall AOCS Leasing Impacts On An Annual Basis[a]

Year	Year No.	Installed Capacity (oil) (mil. bbl.)	Installed Capacity (gas) (bil. Mcf)	Investment (bil. $)	Annual Oil Production[b] (mil. bbl.)	Annual Gas Production[c] (mil. Mcf)
1976	1	0.0	0.0	.66	0.0	0.0
1977	2	0.0	0.0	1.12	0.0	0.0
1978	3	0.0	0.0	1.62	0.0	0.0
1979	4	0.0	0.0	2.08	0.0	0.0
1980	5	0.0	0.0	2.53	0.0	0.0
1981	6	220.8	1031.4	1.51	215.4	1030.4
1982	7	45.9	251.1	1.65	249.7	1280.3
1983	8	45.1	217.5	1.74	281.5	1496.3
1984	9	39.6	251.1	1.48	306.4	1745.7
1985	10	39.6	251.1	0.95	330.1	1994.8
1986	11	35.3	222.0	0.62	348.4	2214.6
1987	12	25.8	154.2	0.27	356.6	2366.4
1988	13	13.4	61.1	0.20	352.3	2425.0
1989	14	21.5	67.3	0.00	356.1	2489.9
1990	15	0.0	0.0		338.7	2487.3
1991	16				332.2	2484.8
1992	17				306.5	2482.4
1993	18				291.6	2479.9
1994	19				239.1	2477.4
1995	20				152.1	2474.9
1996	21				121.7	2472.4
1997	22				107.5	2470.0
1998	23				89.0	2467.5
1999	24				84.6	1453.0
2000	25				71.2	1205.1
2001	26				51.2	990.5
2002	27				29.6	743.1
2003	28				13.5	496.0
2004	29				3.8	277.7
2005	30				3.6	126.2
2006	31				3.4	66.1
2007	32				3.3	0.0
2008	33				3.1	
2009	34				3.0	
2010	35				2.8	
2011	36				2.7	
2012	37				2.5	
2013	38				2.4	
2014	39				2.3	
2015	40				2.2	
2016	41				2.1	
2017	42				2.0	
2018	43				1.9	
2019	44				1.8	
2020	45				0.0	
TOTAL		487.0	2506.8	16.43	5067.9	44697.6

See footnotes for Table 19 on next page.

Annual Tax [d] (bil.$)	Annual Royalty (bil.$)	Bonus Bids (bil.$)	Total Govt. Revenue (bil.$)
.11	.00	.65	.76
.18	.00	.39	.57
.25	.00	.38	.63
.32	.00	.42	.74
.39	.00	.40	.79
.43	.50	.18	1.11
.47	.58	.18	1.23
.51	.67	.17	1.35
.54	.74	.16	1.44
.57	.81	.18	1.56
.60	.87	.17	1.64
.60	.91	.00	1.51
.60	.92		1.52
.60	.93		1.53
.60	.90		1.50
.60	.88		1.48
.60	.85		1.45
.60	.83		1.43
.52	.73		1.25
.37	.58		.95
.32	.53		.85
.30	.51		.81
.27	.48		.75
.22	.34		.56
.19	.29		.48
.14	.22		.36
.09	.15		.24
.05	.09		.14
.03	.04		.07
.02	.02		.04
.01	.02		.03
.00	.01		.01
	.01		.01
	.01		.01
	.01		.01
	.00		.00
11.10	14.43	3.28	28.81

Table 20.-- Government Revenue and Hydrocarbon Production From the Leasing Program Evaluate

	Mid-Atlantic	North Atlantic	South Atlantic	Total AOCS
	Discounted Government Revenue[1]			
Tax	$ 2.13	$ .74	$ .15	$ 3.02
Royalty	2.04	.98	.10	3.12
Bonus Bids	1.71	.45	.14	2.30
Total	5.88	2.17	.39	8.44
	Total Production[2]			
Oil	2.49	1.87	.22	4.58
Natural Gas Liquids	.58	.35	.06	.99
Natural Gas	19.39	11.70	1.87	32.96

[1]All revenue values are in billions of 1974 dollars and are discounted to the beginning of the first lease year at a 12 percent discount rate.

[2]Oil and natural gas liquid (including condensate) values are in billions of barrels, and natural gas values are trillion cubic feet. These values are actual hydrocarbon values and not the converted values which appear in the previous tables.

Footnotes for Table 19

[a]All dollar values are in terms of 1974 prices. Totals may not precisely agree with sums from the regional tables because of rounding and because of the differences in discrete and continuous decline and discounting procedures.

[b]Associated natural gas and natural gas liquids are converted to equivalent barrels of oil on a revenue basis (see pages 17-18). Because of the rising price of natural gas, the conversion is somewhat in error in later years, but the difference is insignificant.

[c]Natural gas liquids are converted to equivalent cubic feet of natural gas on a revenue basis (see pages 17-18). Because of the rising price of natural gas, the conversion is somewhat in error in later years (in the opposite direction of the oil conversion), but the difference is insignificant.

[d]Derived by summing annualized values for each lease sale in each region for both oil and natural gas.

PART IV

An Overview

Given the analytical model and empirical results specified in the previous section, what conclusions can be drawn regarding AOCS leasing policy? This section will attempt to summarize and draw conclusions out of the evaluation presented. In reviewing these conclusions, however, the reader is cautioned to recall the various factors that can impinge on both the absolute and relative results reported. Changes in price, reserves, production costs and leasing strategy could result in a different picture of AOCS leasing than that presented. Although the tendency of most impacts caused by changes in these factors can be discerned from our analysis, the absolute change cannot be shown without new model runs. Moreover, certain effects of exogenous shocks are the result of interdependent parameters which can often result in subtle implications.

Chapter VIII

Summary and Conclusions

Potential hydrocarbon reserve values served as the foundation of the previous analysis. The values used evolved after consideration of a number of sources and forecasting approaches. The result, however, must be considered speculative since no AOCS drilling has taken place. Using a geological approach to hydrocarbon estimation in wildcat areas, median potential recoverable hydrocarbons for the AOCS were estimated at 9.9 billion barrels of oil, 66 trillion cubic feet of natural gas and 2 billion barrels of natural gas liquids and condensate. However, a significant portion of these reserves are expected to be located in water depths greater than 1500 feet. Extraction of resources from these deeper waters is not technologically or economically feasible at present or in the near future. Therefore, our analysis of AOCS production potential was restricted to expected reserves located under water less than 1500 feet deep. Estimated reserves for these areas are 5.7 billion barrels of oil, 38 trillion cubic feet of natural gas, and 1.2 billion barrels of natural gas liquids and condensate.

On the basis of forecast AOCS production costs, energy prices and a leasing schedule, total production from these reserves was estimated at 4.5 billion barrels of oil, 33 trillion cubic feet of natural gas, and 1 billion barrels of natural gas liquids and condensate over a 1976 to 2019 development and production period. These figures are for primary production only; secondary and tertiary production of petroleum was excluded from the analysis. Peak oil production occurs in 1987 at just under one million barrels per day. Peak natural gas production occurs in 1989 at just under six million Mcf per day (2.19 TCF per year). All AOCS production would be terminated by 2019 in the case of oil and by 2006 in the case of natural gas. With the lease program used in the analysis (3 million acres per year), over one-fifth of all the recoverable oil in the AOCS is leased with acreage sold in the first year of the program. The entire acreage is located in the Baltimore Canyon area off the Mid-Atlantic states. All AOCS acreage under less than 1500 feet of water is leased in 11 years.

Seven-eighths of all natural gas reserves are recoverable at forecast prices ($.52 per Mcf in the first year raising at $.01 per year), but almost 100 percent would be recoverable if an initial price of $.82 per Mcf is assumed. If oil prices remain near $11.00 per barrel, four-fifths of recoverable AOCS petroleum reserves would be produced. However, if the oil price falls to $8.00 per barrel, none of the oil deposits in the North Atlantic region would be developed with the investment costs used in this analysis.

Costs of exploring, developing, and producing hydrocarbon reserves depend on a number of factors such as water depth, drilling depth, reserves, climate, and distance from shore. In this analysis, AOCS costs were forecast for an average well in terms of the drilling depth, reserves, and distance from shore factors but then varied for various climatic and water depth conditions. Three regions (North Atlantic, Mid-Atlantic, and South Atlantic) were used for purposes of expressing cost differences due to climatic factors. Two water depth ranges (0-600 feet and 600-1500 feet) were also incorporated in the analysis. Base costs of $10.71, $19.33, and $27.60 per barrel of new annual (peak) capacity (in water up to 600 feet deep) were used for the South, Middle, and North Atlantic regions, respectively. Higher cost estimates were used, by region, for greater water depths.

Over the eleven-year leasing span, a total of $16.4 billion in capital investment plus $3.3 billion in bonus bids (not discounted) is required to develop all the potential hydrocarbon resources (1974 dollars). Almost $3 billion in total investment is required in the peak year of 1980 as compared with $5.2 billion actual investment by 30 of the largest oil companies in all of the United States in 1973 (Chase Manhattan Bank, p. 19). This figure raises the possibility of a capital constraint for a leasing program as rapid as the one analyzed here, especially considering that the $3 billion is for AOCS development alone. The effects of potential capital, manpower, and/or materials constraints, however, have not been treated with in this analysis.

Using the current bonus bidding system, government revenue from the leasing and development of AOCS petroleum resources arises from royalty payments, taxes, and bonus bids. Total government revenue over the production period amounts to $29 billion with a discounted value of $8.4 billion (at a 12 percent discount rate). Of this $8.4 billion, $3.0 billion is from income taxes (36 percent), $3.1 billion from royalty payments (37 percent) and $2.3 billion from bonus bids (27 percent).

In addition to the bonus bidding system, three other bidding systems were evaluated. These included:

1. An increase in fixed royalty (to 40 percent) plus bonus;

2. A royalty bid system (floating royalty); and

3. A fixed profit share rate (of 27 percent) plus a bonus.

The effects of eliminating or maintaining the oil depletion allowance were also evaluated. The bonus bidding system was found to be clearly superior to either of the royalty bidding systems in terms of government revenue or speed of resource development. Although the particular profit share system evaluated in this analysis appeared to be inferior to the bonus bidding system, no general conclusions could be drawn. Further research is required to analyze variations in profit share systems with different income bases and bidding structures. Also, a comparative analysis of risk between the bonus bidding and profit share systems needs to be undertaken.

Elimination of the depletion allowance does not increase total government revenue from leasing of federal resource, and may slightly reduce it. This is because the economic rent is captured by the government either through taxes or the bonus (assuming competitive bidding). Of course, this conclusion would not apply to non-federally owned resources.

In view of the fact that domestic petroleum production has dropped below nine million barrels per day (with approximately 17 million barrels per day being consumed), the schedule and strategy for leasing federal lands containing energy resources will assume a vital role in any public policy to reduce U. S. dependence on foreign sources. It is generally agreed that, outside of Alaska, most large on land hydrocarbon resource areas have been discovered. The Outer Continental Shelf is the largest remaining hydrocarbon resource area available to the U. S. (National Petroleum Council). The U. S. Geological Survey estimates total potential oil and natural gas reserves from OCS areas at 65-130 billion barrels and 395-790 trillion cubic feet, respectively. Although the AOCS portion of this estimate may be 15 percent or less, the location relative to consuming regions makes these potential reserves both important and easily exploited. It is clear, however, from the preceding analysis that future AOCS production (at current reserve forecasts and technology) will not be sufficient to make the east coast region self-sufficient in petroleum or natural gas production. Moreover, the degree to which these projections can be converted to actual reserves and the extent of their recovery depends on more than geological phenomena.

Given environmental considerations and the real issues involved in on land impacts, it appears that the United States should proceed as rapidly as possible to reduce the current uncertainty about AOCS energy resources. For if current forecasts are accurate, alternative sources of supply will be needed on a continuing basis. Plans for these alternatives will also require long lead times. Future economic stability may require that those plans be started today.

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