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Alternative Energy Leasing Strategies and Schedules for the Outer Continental Shelf

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EXECUTIVE SUMMARY

The basic aim of this research was to examine the effects of alternative leasing systems and schedules on United States Outer Continental Shelf (OCS) energy development. This summary provides a brief review of both the steps taken in the analysis and the results derived.

1. The study began with development of estimates concerning the number and sizes of petroleum and natural gas fields which might be discovered on the OCS (to water depths of 200 meters). Using the latest U. S. Geological Survey estimates of undiscovered recoverable OCS hydrocarbon resources in conjunction with historical data on field size distributions, a procedure was developed for estimating the total number of undiscovered fields (petroleum and non-associated natural gas) in each of three size categories and thirteen geological subregions. Using probability techniques, the expected number of fields projected was 646 for petroleum and 443 for natural gas. For oil, these totals were composed of 458, 104, and 84 small (0-50 million barrels), medium (50-100 million barrels) and large (greater than 100 million barrels) fields, respectively. Comparable numbers for non-associated natural gas were 345 small (0-300 million Mcf), 56 medium (300-600 million Mcf), and 42 large (greater than 600 million Mcf) fields.

Using a process of sampling without replacement with probability of selection proportional to size, a hypothetical order of field discovery in each OCS subregion was then determined. This data provided one portion of the information required for the subsequent analysis of leasing schedules.

2. Next, a theoretical structure for understanding and analyzing alternative OCS leasing systems was developed. The structure highlighted major national leasing objectives, with emphasis on risk behavior and risk sharing aspects of alternative systems.

3. The comparison of alternative OCS leasing systems considered the following options:

- Current cash bonus
- Higher fixed royalty
- Variable royalty rate
- Profit share with IRS income base
- Annuity capital recovery profit share
- British type profit share
- Indonesian type production sharing
- Variable rate profit share
- Working interest

- Work program
- Royalty bidding
- Profit share bidding.

4. A generalized resource leasing policy evaluation model was developed for use in analyzing the various leasing alternatives and leasing schedules. The model uses basic economic concepts, such as discounted cash flow techniques, and incorporates geologic, engineering, and economic relationships relevant to the petroleum industry in order to stimulate the offshore oil and natural gas development process. Monte Carlo simulation techniques are utilized to handle uncertainty in future resource prices, investment and operating costs, the presence or absence of resources, and the amount of reserves discovered. The exploration and development phases of the lease development process are separated in order to better simulate private sector decisions on lease development.

5. Outputs of the leasing model include statistics on the following variables:

- Production time horizon
- Installed production capacity
- Present value of royalty payments
- Present value of profit share payments
- Present value of depletion
- Present value of taxes
- Production (total and time profiles)
- Reserve discovery size
- Total production cost
- After tax net present value
- Percentage dry tracts.

Additional outputs can be obtained for tests of specific lease systems or policy options.

6. Production cost functions relating production cost per unit of annual installed capacity to reserve discovery size were estimated for each OCS subregion using data published by the National Petroleum Council and earlier work by the authors. Production cost functions for each of five climatic regions for both oil and non-associated natural gas were incorporated into the generalized leasing model.

7. The analysis of alternative leasing systems first examines the viability of alternative systems in marginal production areas; that is, production areas where costs were high in relation to assumed prices. Then the alternative systems were compared on more profitable production areas. Three sets of alternative price expectations were used for the comparisons. In general, it was found that any of the systems would be viable (permit development) if the contingency rates were properly set by the government, ex ante. However, regardless of the system used, the analysis showed that certain reservoir discovery sizes in some of the OCS subregions will not be developed because of unfavorable economic conditions.

8. Risk averse behavior was assumed on the part of private sector bidders. Given this assumption, five criteria were selected for a more rigorous comparison of the alternative systems. These included system impacts on:

- Government revenue
- Total expected production
- Chance of a less than normal profit
- Bonus ratio -- ratio of the after tax net present value of each system to that of the current cash bonus system
- Ratio of the mean after tax net present value to its standard deviation.

The last three criteria provide measures of system effectiveness with respect to transferring risk from the private to the public sector.

9. Using these criteria in evaluating both marginal and more profitable production conditions, five of the alternative lease systems appeared to be as good as or better than the current cash bonus system. Each of these systems uses the cash bonus as the bid variable. The five systems are:

- Royalty system with the royalty rate variable with the value of production in each year
- Fixed rate annuity capital recovery profit share system
- Variable rate annuity capital recovery profit share system
- Fixed rate British type capital recovery profit share system
- Variable rate British type capital recovery profit share system.

Although use of the variable rate systems had a tendency to lengthen production time horizons in certain situations, the impact on present values was unimportant and did not affect the conclusions derived. Analytical results were also consistent over a range of price and reserve expectations. In all tests, the contingency rates used for revenue generation during production were set so as to permit, if possible, economic development in marginal production areas (using an $11.00 per barrel and $.60 per Mcf price assumption).

10. Other systems evaluated were either inferior to or no better than the current cash bonus system. These systems include the higher fixed rate royalty system, the royalty system with the rate variable with the level of production, and the fixed and variable rate IRS based profit share systems.

11. Next, four alternative leasing schedules were developed for analysis of schedule impacts using the current leasing system and one of the five superior systems (the fixed rate annuity capital recovery profit share system). These schedules included one which would provide for uniform leasing across OCS subregions and through time, one designed to maximize economic rent, one designed to maximize production, and one designed to maximize environmental preservation. For analytical purposes, it was assumed that seventy-five percent of the total undiscovered recoverable resource in any OCS subregion would be discovered using the schedules. Both ten and twenty year leasing time horizons were tested under this assumption using three alternative price expectation assumptions. The resulting forty-eight combinations (4 leasing schedules X 2 leasing time horizons X 3 price expectations X 2 leasing systems) were compared on the basis of economic rent generated and present barrel equivalents of oil production.

12. In terms of the present value of economic rent, the following results were derived:

- Economic rent varies significantly with price
- The present value of economic rent is approximately twenty-five percent lower for the twenty year schedule than for the ten year leasing schedule
- There is no significant difference in expected economic rent between the two leasing systems tested
- Differences in present value of economic rent among the four schedules were minor (less than four percent), but statistically significant
- Environmental preservation (as defined for scheduling) can be accomplished with little loss in present value economic rent.

13. Using the accelerated leasing schedule, peak OCS liquids (oil plus NGL) production occurs about 1989 at a level of one billion barrels per year (2.9 million barrels per day) assuming a 1976 date for schedule commencement, and excluding production from existing OCS leases. Therefore, even with an accelerated leasing schedule, new OCS production could never be expected to completely replace the current level of petroleum imports.

14. Total expected liquids production from the OCS is 11-13 billion barrels; total expected gas production is 39-64 billion Mcf. These production

estimates are dependent upon a number of factors such as assumed resource prices, cost estimates, and economic and geologic assumptions utilized in this analysis. The estimates are critically dependent upon the basic input oil and gas reserve data from the U. S. Geological Survey. This data is in the form of probabilistic expectations of oil and gas reserves to a water depth of 200 meters. Major changes in any of the basic input data could produce significant changes in the production estimates which resulted from this study.

15. Primary OCS hydrocarbon reserves (to 200 meters) would be exhausted by 2015 (assuming a twenty year leasing schedule) and by 2005 (assuming a ten year leasing schedule).

16. Natural gas production is more responsive to changes in expected price than oil production. A change in the expected natural gas price from $.60 to $2.00 increased the total expected natural gas production from 38 to 64 billion Mcf. This result implies that deregulating natural gas prices (or substantially raising the price) could stimulate production.

17. In general, the comparison of alternative leasing schedules revealed that the differences among the selected schedules were relatively minor. This result again implies that the type of environmental preservation considered in this study could be accomplished at low cost to society.

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Chapter I

Introduction

The United States Outer Continental Shelf (OCS) and slope constitute the last major frontier for domestic petroleum and natural gas exploration. Current U. S. Geological Survey estimates suggest that almost one-half of all undiscovered oil resources and one-quarter of similarly defined natural gas resources may be located in the OCS and in the frontier provinces of Alaska (Miller, et al., 1975). Others have estimated that over sixty percent of both resources yet to be discovered are contained within OCS areas (Mobil Oil Corp., 1974).

The unique character of the OCS with regard to potential energy supply, however, does not stem solely from the magnitude of the resources which may be located there. The OCS is unusual in an institutional, as well as geological, sense. That is, it is owned and controlled by one entity -- the public through its elected and appointed representatives at the federal level (for areas beyond the three mile limit except for the Gulf of Mexico where the federal government controls beyond nine miles). The combined factors of public ownership and potential resource availability have focused attention on both the methods used by the government to manage these areas and the proper course of future OCS activities (House Select Ad Hoc Committee on the OCS).

Some of the management concerns involve potential offshore environmental problems and secondary impacts to onshore areas that might result from development of any energy resources that are present. Although these issues are important, they are not a major thrust of this study. Potential environmental problems stemming from OCS development may be minor relative to alternative energy sources (U. S. Department of the Interior, Final Environmental Statement, Vol. 2). In any case, to the extent that environmental factors can be internalized to the development process, only the cost relationships of the primary activity are affected. Evaluations of other OCS issues can, thereby, accomodate some of these externalities by modifying technical and cost relationships. Onshore impacts are, on the other hand, less likely to be internalized to a developer. Yet little can be said about the potential for such impacts until the scope, schedule and probable result of primary exploration and development activity is better understood.

In general, it is the latter which requires study and evaluation if informed public decisions, at all levels, are to be made relative to the management of this vast area of public domain. Energy resource exploration, development and production from the OCS is, therefore, the central focus of this research. However, a study of this area cannot be limited to the geological or purely physical aspects of the potential energy resources it contains, nor to technological issues related to resource exploitation. Rather, all of these aspects must be coupled with institutional and economic considerations before balanced alternatives for future management decisions can be properly evaluated.

In this research, we consider the interrelationship of these various elements in a systematic and replicable manner. The objective is to develop techniques for simulating the social and private implications of various considerations ranging from alternative management policies to changes in the data used as a basis for decision making. Changing circumstances with respect to such considerations may have a critical bearing on the attainment of objectives being fostered for the use of public domain lands. For example, what are the physical, environmental and economic implications of the following:

1. Alternative systems designed to lease public domain lands to the private sector for exploration and/or development of potential energy resources;

2. Alternative tax regulations related to energy resource exploitation;

3. Modified information concerning the potential for resource recovery;

4. Equipment or manpower constraints affecting a development schedule;

5. Alternative levels of domestic petroleum and natural gas prices for production from different reservoir sizes located in regions with different production cost relationships;

6. Alternative schedules for exploration and development in a given OCS region and the priority with which different regions are selected; and

7. Differential knowledge on the part of the government and the private sector in a prebid situation (assuming that competitive leasing to the private sector is the means used to foster energy resource development) regarding resource or other data related to bidding behavior.

Issues such as these are now being raised more frequently by our federal resource managers, the Congress and informed interest groups. Both Houses of Congress are considering or have passed comprehensive legislation modifying the original 1953 Outer Continental Shelf Lands Act (67 Stat. 462; 42 U.S.C. Secs. 133-1343) which provides authority for offshore resource development. The Department of the Interior is performing limited experiments with different leasing systems in an effort to foster public objectives with regard to OCS development. The energy industry issues forecasts of possible implications for OCS development that would stem from numerous changes suggested for our tax codes, leasing systems, leasing schedules and domestic energy price levels. It is, perhaps, no surprise that public debate over these issues has often produced no consensus as to a future course of action. Issues are being raised with claims and counter claims about appropriate management policies. Yet little, in depth, research has been made available for public review and comment.

More importantly, in the planning activity that followed the Arab oil embargo, the authors know of no comprehensive study of OCS potential for energy production under alternative management policies and development (leasing) schedules. Even the Project Independence Report of the Federal Energy Administration (Oil, 1974) did not evaluate alternative strategies (of the type outlined above) or schedules for OCS activity. As the United States attempts to formulate a long range energy policy, however, such an evaluation will be required. For without it, neither the time profile for production nor the present value economic effects of changes in public policy can be ascertained.

It is to these concerns that the research contained in this report is dedicated. Although an exhaustive evaluation of all possible changes in management policies or other relevant circumstances is beyond the scope of any one study, we hope to provide an appropriate analytical framework for such evaluations and highlight the use of it through application to some of the important policy issues currently being discussed in the political arena. The study is divided into six main components. In the first, the geology and energy potential of the United States OCS is examined and alternative scenarios are developed regarding the quantity and location of possible hydrocarbon resources. As part of this effort, estimates of the numbers and distribution of undiscovered hydrocarbon fields of various sizes are made. This information then serves as the basis for subsequent policy analysis. In addition, a framework is established within which judgements can be made concerning the order and rate of leasing (the leasing schedule); and the resultant effect on the hydrocarbon discovery process.

Second, a discussion of alternative leasing systems is presented and these systems are compared with current United States leasing and resource management policy. The basic principles of each system are pointed out and the underlying theory of alternative systems discussed. The principal focus is on the risk sharing capability of various approaches.

Third, an analytical framework is formulated for later use in analyzing alternative leasing strategies and schedules. This framework takes the form of a discounted cash flow simulation model using Monte Carlo techniques for incorporating risk with respect to critical variables. In addition, geologic, institutional and engineering considerations relevant to OCS decision making are included in the model specification. The net result is a model designed to encompass the elements of expected market behavior when OCS lands are offered for lease to the private sector.[1] Impacts of alternative management policies on a variety of economic factors, such as resource discoveries,

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[1]Note that the approach used here is substantially more sophisticated than previous models formulated by the authors (Kalter, *et al*., 1975; Kalter, *et al*., 1974; Kalter and Tyner, 1975). For example, the exploration and development phases of the discovery process are now handled separately, taxation issues are more thoroughly treated and investment time lags (with associated tax interactions) have been incorporated. In addition, issues of joint cost, associated with development of a second resource like natural gas, and numerous other technical and policy oriented features have been incorporated.

production rates and timing, investment requirements, government revenue, and development risk can be obtained from model simulations.

Fourth, potential costs of hydrocarbon exploration, development and production in various regions and for different leasehold sizes and reservoir discoveries are described and forecast. When used in conjunction with resource estimates and the analytical techniques specified, these production cost values complete the data needed for an economic evaluation of management policy.

The resource and cost information is first used in conjunction with the evaluation model to analyze alternative leasing systems which have been suggested for OCS development. The viability of these systems under different conditions and their impact on risk transfer is the main focus, but other economic impacts are also reviewed.

Finally, the accumulated study results are used as the basis for a major analysis of leasing schedules for the OCS under several alternative leasing systems and various market conditions. Implications of various schedules for production profiles of oil and natural gas and for present value economic results provide the focus. What emerges is a picture of what can be expected from the OCS in the way of future domestic hydrocarbon supply augmentation under various market conditions and management policies.

Chapter II

United States Outer Continental Shelf Energy Potential

To evaluate alternative management options for energy development on the OCS, estimates of the amount and characteristics of potential recoverable hydrocarbons contained in the relevant sedimentary basins must be made.[2] Physical constraints imposed by the geology and geography of offshore areas must also be examined; for it is the geology which controls the distribution of oil and natural gas and the geology, geography, and physiography which impose economic costs that limit the amount of hydrocarbons recoverable from those in-place.

Specifically, two categories of geologic based information are necessary for the analysis to be carried out in this study. First, estimates of the numbers of undiscovered oil and natural gas fields distributed throughout the various OCS areas by size classification are required. This information category includes several types of data such as distributions of expected recoverable reserves and expected field size distributions for each province. Second, judgements as to the order and rate of field discovery under alternative leasing schedules must be made. Data regarding these issues are, obviously, limited and subject to substantial uncertainty Except for the Gulf of Mexico and portions of the OCS off California, offshore lands of the United States are "frontier" areas in the sense that little concrete geologic data are available. Geophysical seismic surveys may be partially completed for some areas and extrapolations from land-based geology can often be made. But only after actual exploration and drilling can increased certainty regarding resource distribution be obtained. Yet, for policy purposes, this delay is unacceptable. Thus, available data must be used in conjunction with necessary assumptions and generalizations. What needs to be emphasized is that the resulting estimates are only as good as the geologic information available for the areas or regions under investigation. Probability and/or sensitivity techniques must, therefore, be employed to provide additional information concerning analytical results.

In this chapter, the geologic issues raised above are analyzed and a methodology for determining base data estimates is evolved. The process begins with a discussion of the available estimates of OCS hydrocarbon potential and a review of the various estimation procedures used in arriving at these estimates. The most appropriate data source on undiscovered resources by offshore province is then selected for the analysis, and the resource estimates are modified so that the reserve data conceptually matches the requirements of the analytical model to be developed in Chapter IV.

The next step in the process is to select a data source for field size distributions. After modifications of the selected theoretical field size

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[2]The Outer Continental Shelf (OCS) of the United States is defined here as the portion of the ocean floor which is beyond the jurisdictional limits of the individual states.

distributions and partitioning the distributions into field size classes, the reserve data and field size distributions by subregion are used together to determine the numbers of fields of each size which could be discovered. Variance estimates for each field size classification are also provided. The mean and variance (standard deviation) for each subregional field size classification become the basic geologic inputs to the policy evaluation model. Subregional mean reserve estimates, field size class means, and numbers of fields in each class are then combined in a simplified discovery sequence model to simulate the hypothetical order of field discovery. This discovery order is conceptually linked to potential leasing schedules. Each of these steps is described in detail in the material that follows.

Estimates of Geologic Potential: Attention has recently been focused on differences between various estimates of undiscoverable hydrocarbon resources for the United States. Although such estimates are of necessity subjective, the procedures used in incorporating the subjective judgements may be analytically sound. That not withstanding, the values produced by the U. S. Geological Survey (USGS) from 1960 through 1974 have been consistently higher, by factors of three to five, than estimates made by other groups or individuals (Zapp, 1962; Hendricks, 1965; Theobald, et al., 1972; USGS, 1974). Examples of the latter include several major oil companies (Gillette, 1974), a distinguished USGS researcher (Hubbert, 1974), and, now, the most recent USGS estimates (Miller, et al., 1975).

What factors would produce such divergent estimates? Even in geologically well-known areas, the nature of hydrocarbon occurrence in "blind" traps thousands of feet below ground, and the still poorly understood relations between timing and nature of origin, migration and entrapment processes, cause all estimates of hydrocarbon resources to contain inherent uncertainties. Extensive research has been done on identifying characteristics of oil and/or natural gas producing basins. Yet, no models have yet been devised which uniquely correlate type of geology with hydrocarbon occurrence. Results of these studies have, nonetheless, been useful in delineating prospective favorable geological areas or provinces. Potential petroleum reservoir rocks and traps, both structural and stratigraphic, are routinely recognized using various geological and geophysical methods. However, it must be emphasized that even the most favorable prospects, in geological terms, cannot be verified for hydrocarbon production potential without actually drilling a well.[3] When considering frontier regions such as the OCS, the uncertainty is even greater because all estimates of undiscovered resources are made with extremely general geological information.

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[3]A most striking illustration of this statement is the Destin Dome (Oil and Gas Journal, 1975), off the west coast of Florida. Three major petroleum companies, Exxon, Mobil and Champlin, paid $632.4 million for six leases covering the eastern crest of the largest and seemingly most promising structure ever encountered in the Gulf Coast region. After spending an additional $15 million on seven dry holes, Exxon has no further drilling plans in the area. The lack of producible hydrocarbons in this geologically well-explored and favorable structure emphasizes the risks and uncertainties involved in making resource estimates, even on a local scale.

In addition to these geological uncertainties, political, economic and technological considerations may induce bias and high variance into almost any resource evaluation. Also, the ultimate use to which a resource evaluation will be put will tend to influence not only the format of the analysis (Kaufman, 1975) but also, perhaps, the output. With the above considerations in mind, a closer look at estimation methods and their results would be in order.

A Review of Estimation Procedures: The pre-1975 U. S. Geological Survey methods of evaluating petroleum resources were based on the assumption that an area could be called "adequately" explored for hydrocarbon potential when, on average, one 6,000 foot exploratory well was drilled for every two square miles of potential sedimentary rock-covered area. Based on these criteria, the 1.86 million square miles of onshore and offshore sedimentary rocks of the counterminous United States which are thick enough to contain oil and gas could be adequately explored by exploratory drilling totalling five billion feet. Because approximately one billion feet of exploratory footage had been drilled through the late 1950's, the reasoning held that eighty percent of the United States remained to be explored. Estimates of the early 1960's assumed that the rate of discovery of oil would be equal to the average quantity discovered per foot drilled in the past and, thus, 460 billion barrels of oil were estimated yet to be discovered (Zapp, 1962). In 1965, in response to objections, principally by M. King Hubbert, this discovery rate was reduced to one half the former rate per foot drilled and a new estimate of 400 billion barrels ultimate production (including cumulative past production) was obtained (Hendricks, 1965). As late as 1974, the USGS estimates of undiscovered oil were in the range of 200-400 billion barrels of oil and natural gas liquids for the United States (including Alaska) onshore and offshore to water depths of 200 meters (USGS, 1974).

For years the USGS' geological/volumetric approach was challenged by Hubbert (1962, 1969). His historical extrapolation techniques rely on the theory that oil resources are finite and that a production versus time graph would be bell shaped. Petroleum production would grow exponentially at first, level off and then approach an exponential decline. In 1956, using drilling, discovery, and production statistics from 1860 to the present, Hubbert predicted the United States oil production peak which occurred in 1970. Hubbert's arguments are also based on historical records that returns per exploration foot drilled have fallen from 276 barrels in the 1930's to 35 barrels per foot in 1965 and as low as 30 barrels per foot in 1972 (Gillette, 1974). Using projections based upon such statistics, Hubbert's estimate of recoverable oil and natural gas liquids (NGL) is 67 million barrels, or about one-third of the USGS' lowest estimate in 1974 (Hubbert, 1974).

In more recent years, several oil companies, Exxon (Garrett, et al., 1974) and Mobil (Mobil Oil Corp., 1975) and the USGS Resource Appraisal Group (Miller, et al., 1975) have developed models for estimating undiscovered petroleum resources using subjectively determined input distributions for certain geologic parameters. These parameters include such variables as gas-oil ratios, oil recovery in barrels per acre-foot, barrels per cubic mile of sediment, ultimate recovery factors, etc. Judgements of high, low and most likely values for these parameters are commonly elicited from experts and incorporated in the calculations. Using this method, the United States can be divided into provinces of similar geologic structure and stratigraphic characteristics. The geological parameters for these individual areas are then estimated (often using known geological areas as analogs), and quantities of undiscovered hydrocarbons for each province are calculated. With province results in the form of probability distributions, estimates for the entire United States or for any other aggregation of individual provinces can be obtained by using Monte Carlo simulation techniques to sum the values for individual regions. Output is usually in terms of a high probability value, a low probability value and a most likely value. The technique is particularly appropriate for estimating resources in frontier regions, where little statistical information has been accumulated on discovery-to-wildcat ratios, sizes of oil pools, and other data obtained as an area is actually explored. Using such techniques, Mobil's "expected value" for undiscovered oil and natural gas liquids for the United States onshore and offshore to water depths of 1,829 meters (6,000 feet) is 88 billion barrels (Gillette, 1974), while the USGS Resource Appraisal Group's "mean" value is 98 billion barrels (to water depths of 200 meters).

Probability models for determining amounts of liquid hydrocarbons yet to be discovered in particular basins or those resources associated with a particular type of trapping process have also been proposed (see Kaufman, 1974; Kaufman, et al., 1975). These models rely on the assimilation of drilling information as exploration proceeds in a given area. Thus, they seem most useful in the analysis of fairly well-known basins or of basins presently being explored and drilled in comparison to the unexplored offshore frontier areas to be considered in this study.

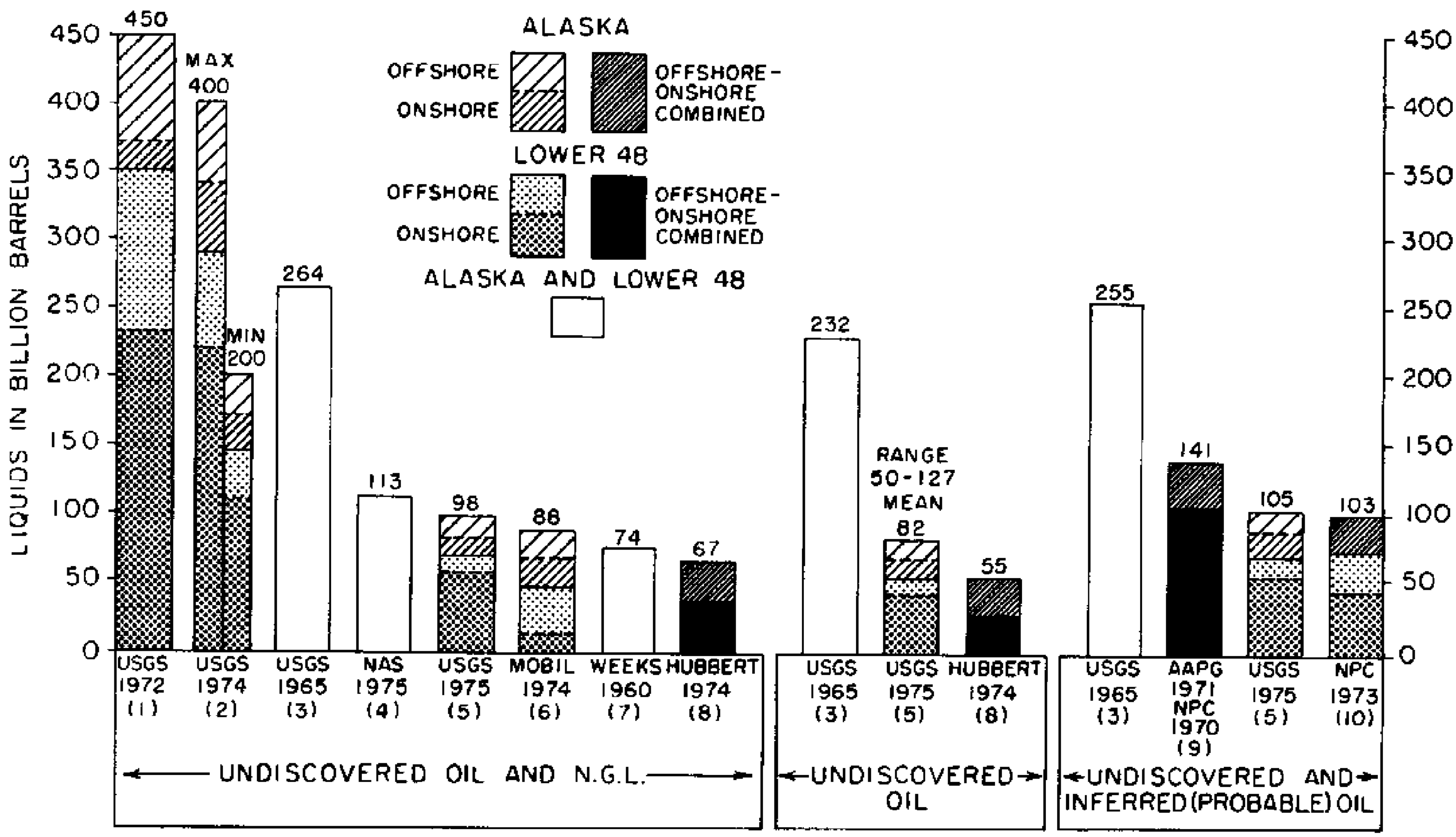
Other groups and individuals have presented estimates of United States petroleum resources. The methods vary somewhat and resulting values reflect different techniques, different subjective judgements and assumptions, and also differences in area considered -- especially in the offshore provinces. Water depths of 200 meters (660 feet), 1,829 meters (6,000 feet) and 2,500 meters (8,200 feet) have been used as cutoff limits for various reports. Figures 1 and 2 provide summary comparisons of a number of oil and natural gas resource estimates for the United States.

Probability Estimates of Energy Resources for OCS Provinces: For purposes of this study, it is obvious that aggregate resource estimates for the United States or its OCS would not provide the detail required to evaluate alternative management policies. Regional variations in critical variables, such as geology and production costs, point up the need for disaggregated estimates.

Only one data source was available which met the general criteria cited above and also provided sufficient background information to allow for further data manipulation. That source was the most recent USGS resource evaluation (Miller, et al., 1975; plus background data supplied by the USGS Denver office).

Figures 3 and 4 detail the specific OCS provinces evaluated by the USGS Resource Appraisal Group. From these two maps, it should be noted that the Atlantic Outer Continental Shelf region to water depths of 200 meters is divided into four provinces, the Gulf of Mexico into two provinces, the Pacific offshore region into nine provinces, and Alaskan offshore regions into thirteen provinces. These twenty eight offshore provinces include all areas

Figure 1.--Comparative Estimates of Undiscovered Recoverable Oil Resources in the United States



(1) Theobald and others, U. S. Geological Survey Circular 650, 1972. Includes water depth to 2,500 meters (8,200 feet).

(2) U. S. Geological Survey News Release, March 26, 1974. Includes water depth to 200 meters (660 feet).

(3) Hendricks, U. S. Geological Survey Circular 522, 1965. Adjusted through 1974. Includes water depth to 200 meters (660 feet).

(4) National Academy of Sciences, "Mineral Resources and the Environment," 1975. (See National Research Council). Water depth not indicated.

(5) U. S. Geological Survey "Mean," Oil and Gas Branch Appraisal Group, 1975. Includes water depth to 200 meters (660 feet).

(6) Mobil Oil Corporation, Expected Value: Science, 12 July 1974. (see Gillette). Includes water depth to 1,830 meters (6,000 feet).

(7) Weeks, L.G., Geotimes, July-August, 1960. Adjusted through 1974. Water depth not indicated.

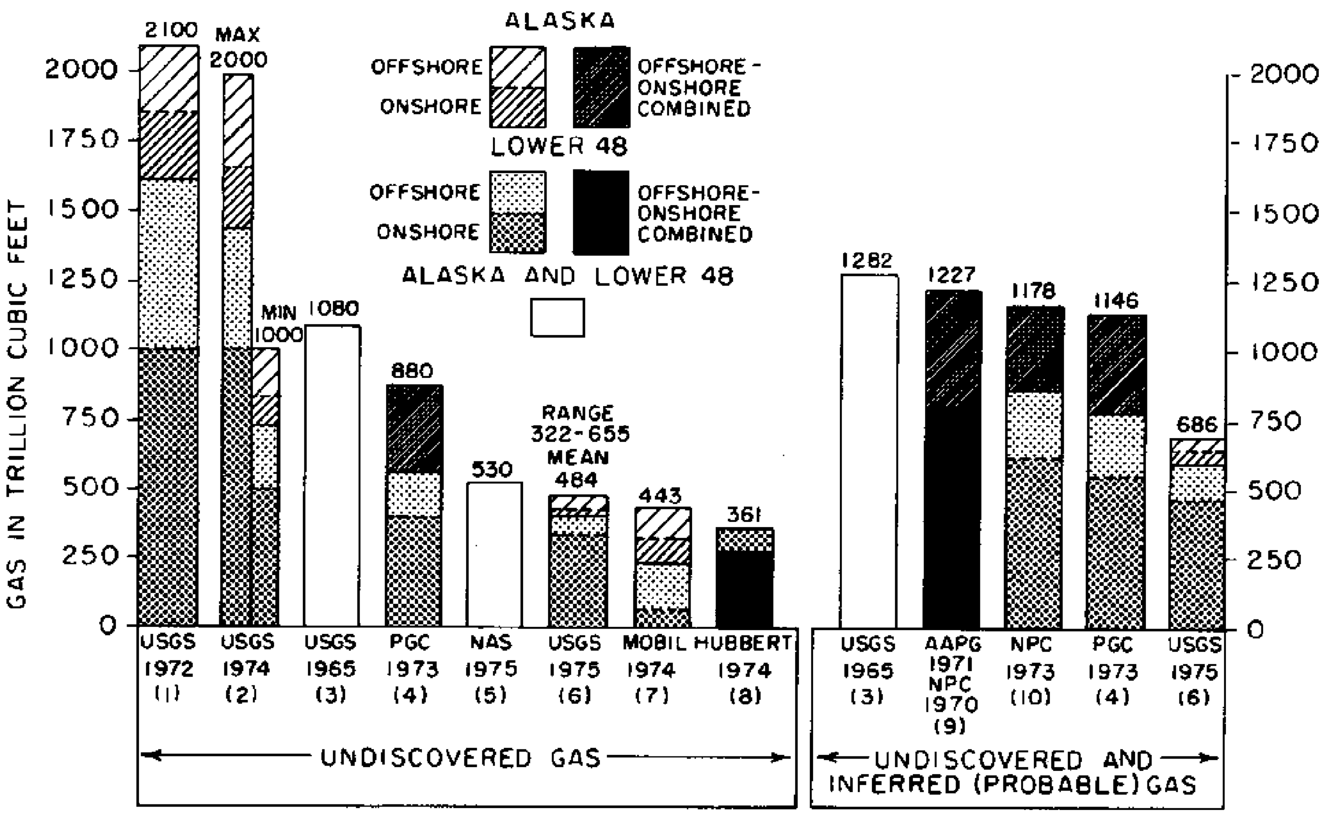
(8) Hubbert, Senate Committee Report, 1974. Includes water depth to 200 meters (660 feet).

(9) American Association of Petroleum Geologists Mem. 15, 1971. Also National Petroleum Council, "Future petroleum provinces of the United States," 1970. Some areas are excluded from this estimate. Includes water depth to 2,500 meters (8,200 feet).

(10) National Petroleum Council, "U. S. Energy outlook -- oil and gas availability," 1973. Includes water depth to 2,500 meters (8,200 feet).

Source: Miller, et al., 1975.

Figure 2.--Comparative Estimates of Undiscovered Recoverable Natural Gas Resources in the United States



(1) Theobald and others, U. S. Geological Survey Circular 650, 1972. Includes water depth to 2,500 meters (8,200 feet).

(2) U. S. Geological Survey News Release, March 26, 1974. Includes water depth to 200 meters (660 feet).

(3) Hendricks, U. S. Geological Survey Circular 522, 1965. Adjusted through 1974. Includes water depth to 200 meters (660 feet).

(4) Potential Gas Committee, "Potential Supply of Natural Gas in the United States," 1973. Includes water depth to 460 meters (1,500 feet).

(5) National Academy of Sciences, "Mineral Resources and the Environment," 1975. (See National Research Council). Water depth not indicated.

(6) U. S. Geological Survey "Mean", Oil and Gas Branch Resource Appraisal Group, 1975. Includes water depth to 200 meters (660 feet).

(7) Mobil Oil Corp., Expected Value: Science, 12 July 1974. (See Gillette). Includes water depth to 1,830 meters (6,000 feet).

(8) Hubbert, Senate Committee Report, 1974. Includes water depth to 200 meters (660 feet).

(9) American Association of Petroleum Geologists Mem. 15, 1971. Also National Petroleum Council, "Future Petroleum Provinces of the United States," 1970. Some areas are excluded from this estimate. Includes water depth to 2,500 meters (8,200 feet).

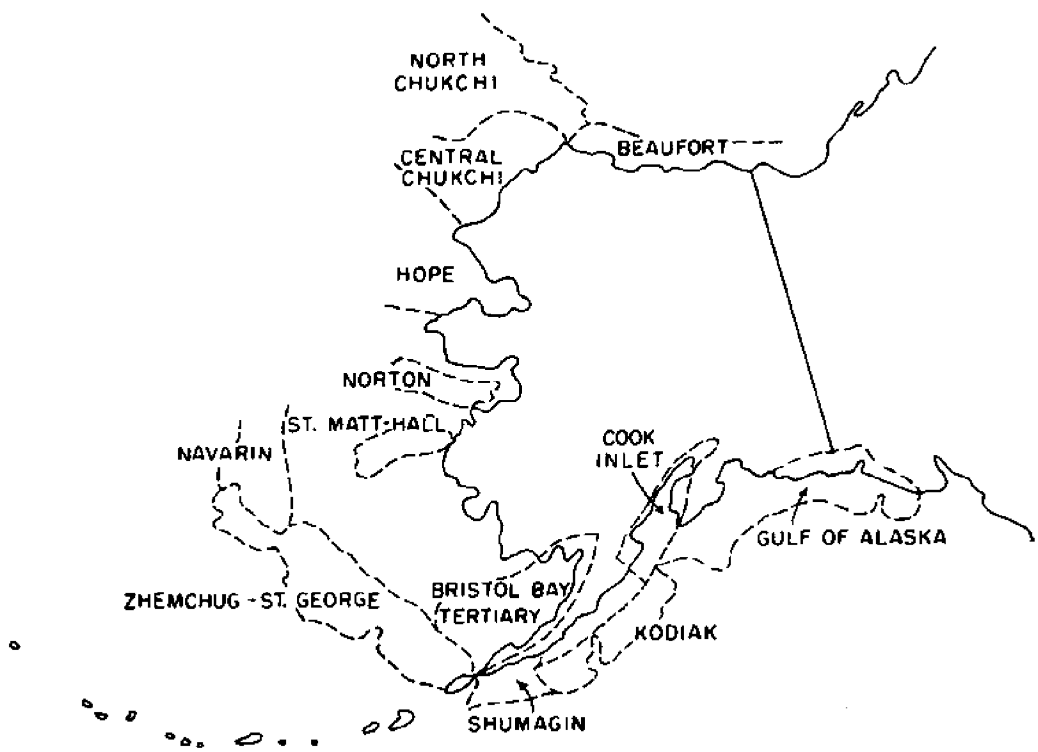
(10) National Petroleum Council, "U. S. Energy Outlook -- Oil and Gas Availability," 1973. Includes water depth to 2,500 meters (8,200 feet).

Source: Miller, et al., 1975.

Figure 3.--Map of the Conterminous Lower 48 United States Showing USGS Resource Appraisal Group Regional OCS Boundaries

Source: Miller, et al., 1975.

Figure 4.--Map of Alaska Showing USGS Resource Appraisal Group Regional OCS Boundaries.



Source: Miller, et al., 1975.

to be considered for federal leasing according to the Proposed OCS Leasing Schedule of June, 1975 (U. S. Department of the Interior, 1975).[4]

The subjective resource appraisals for individual geologic provinces used by the USGS group in preparing their appraisal were obtained from the basic data files at the Denver office. Table 1 summarizes the results of the appraisals for undiscovered recoverable liquid hydrocarbon and natural gas from the offshore provinces shown in Figures 3 and 4. The appraisal results shown in Table 1 include the following information:

1. A marginal probability estimate of the chance that any economically recoverable oil or natural gas is contained in the region under consideration.

2. Given that recoverable hydrocarbons are found, a low estimate with a 95 percent probability that at least that amount exists.

3. Given that recoverable hydrocarbons are found, a high estimate with a five percent probability that at least that amount exists.

4. Given that recoverable hydrocarbons are found, a mean estimate.

Using these data and the assumption that the subjective probabilities (prior beliefs) for hydrocarbon resource estimates are distributed lognormally, Dr. G. M. Kaufman of M.I.T. fit the USGS estimates to lognormal curves (personal communication, Betty M. Miller, Gordon M. Kaufman). In addition, Dr. Kaufman provided the 95 percent, 5 percent, and mean values for each province and the standard deviation for each lognormal distribution (also shown in Table 1). These distributions, then, are Baysian prior distributions. In other words, they represent the distribution of subjective expectations on future resource discoveries for each province.

Aggregate mean values and high and low probability estimates for the offshore regions of the United States and for the total OCS are also included in Table 1. It should be noted that Monte Carlo simulation techniques are needed to sum the <u>probability distributions</u> of two or more provinces or of two or more regions. Thus, except for the mean values, a simple addition of the values for the individual provinces of a geologic region will not produce the aggregated resource distributions shown.

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[4]However, the USGS appraisal includes only OCS areas to water depths of 200 meters (660 feet) and makes use of subjective judgements based on a continuation of pre-1974 price-cost relationships. Neither assumption can be sustained over the long term, as leasing activity in these areas expands and market conditions change. Because of these factors, the results of the USGS appraisal are probably conservative (given acceptance of the methods, the data used, and the judgements made). No other published appraisals are available, however, with the detail required for this study. Thus, we will not be able to consider all OCS areas or resources potentially available to the United States for leasing. When more detailed resource data become available, the results provided here should be updated and made more comprehensive.

Table 1.--USGS Resource Appraisal Group Estimates of Undiscovered Recoverable Oil and Natural Gas Resources for the OCS Areas of the United States

Region, Subregions and Province Names	Oil in Billions of Barrels						Gas in Trillions of Cubic Feet					
	Marg. Prob.	95%	5%	Mean	Std. Dev.	Cond. Mean	Marg. Prob.	95%	5%	Mean	Std. Dev.	Cond. Mean
ALASKA OFFSHORE												
Arctic Ocean												
Beaufort Sea	.75	0	7.60	3.28	3.5800	4.37	.75	0	19.30	8.20	22.380	10.93
North Chukchi	.60	0	6.20	1.89	1.7600	3.15	.60	0	19.50	5.67	15.800	9.45
Central Chukchi	.70	0	11.90	4.41	7.7700	6.30	.70	0	30.00	11.00	47.800	15.71
Hope	.30	0	0.60	0.13	0.0050	0.43	.50	0	3.30	0.86	0.370	1.72
Bering Sea												
Norton	.40	0	2.19	0.54	0.1100	1.35	.60	0	2.80	0.85	0.320	1.42
St. Matthew-Hall				Negligible						Negligible		
Bristol	.50	0	2.50	0.71	0.2100	1.42	.50	0	5.40	1.64	0.930	3.28
Navarin	.30	0	1.90	0.36	0.0500	1.20	.30	0	4.80	0.93	0.330	3.10
Zhemchug-St. George Basin	.50	0	5.10	1.32	0.8300	2.64	.50	0	13.00	3.30	5.210	6.60
Pacific Margin Basins												
Cook Inlet	1.00	0.5	2.30	1.19	0.5900	1.19	1.00	1.0	4.50	2.39	1.170	2.39
Eastern Gulf of Alaska	.70	0	4.40	1.13	1.7000	1.61	.70	0	13.00	3.39	15.310	4.84
Kodiak Tertiary	.40	0	1.00	0.23	0.0800	0.58	.40	0	3.50	0.69	0.700	1.73
Shumagin Shelf	.20	0	0.25	0.04	0.0005	0.20	.20	0	0.50	0.08	0.002	0.40
PACIFIC COAST OFFSHORE												
S. California Borderlands												
Inner Basins	1.00	0.4	2.00	1.01	0.5200	1.01	1.00	0.4	2.00	1.01	0.520	1.01
Outer Basins and Ridges	.40	0	0.24	0.06	0.0010	0.15	.40	0	0.24	0.06	0.001	0.15
Santa Barbara Channel	1.00	0.6	3.00	1.51	0.7900	1.51	1.00	0.7	3.30	1.70	0.850	1.70
Santa Cruz	.50	0	0.37	0.12	0.0050	0.24	.50	0	0.36	0.12	0.005	0.24
Northern Pacific Offshore												
Santa Maria	.60	0	0.28	0.11	0.0040	0.18	.60	0	0.28	0.11	0.004	0.18
Bodega	.40	0	0.53	0.13	0.0070	0.33	.40	0	0.53	0.13	0.007	0.33
Pt. Arena				Negligible						Negligible		
Eel River				Negligible						Negligible		
Oregon-Washington	.30	0	0.72	0.15	0.0070	0.50	.30	0	1.70	0.35	0.040	1.17

Table 1.--Continued

Region, Subregion and Province Names	Oil in Billions of Barrels						Gas in Trillions of Cubic Feet					
	Marg. Prob.	95%	5%	Mean	Std. Dev.	Cond. Mean	Marg. Prob.	95%	5%	Mean	Std. Dev.	Cond. Mean
GULF OF MEXICO												
Florida Gulf Platform	.70	0	2.80	0.99	0.4500	1.41	.70	0	2.80	0.99	0.4500	1.41
Central and Western Continental Shelf	1.00	2.0	6.50	3.84	1.4200	3.84	1.00	17.0	90.00	49.00	24.0500	49.00
ATLANTIC COAST OFFSHORE												
North Atlantic Shelf	.60	0	2.50	0.89	0.3100	1.48	.60	0	13.20	4.44	7.7700	7.40
Central Atlantic Shelf	.70	0	4.60	1.76	1.2400	2.51	.70	0	14.20	5.29	11.1800	7.56
South Atlantic Shelf	.40	0	1.25	0.34	0.0300	0.85	.40	0	2.50	0.67	0.1400	1.68
Southeast Florida Shelf and Straits				Negligible						Negligible		
TOTALS												
Alaska Offshore	-	3	31	15.23	-	24.44	-	8	80	39.00	-	61.57
Pacific Coast Offshore	-	2	5	3.09	-	3.92	-	2	6	3.48	-	4.78
Gulf of Mexico Offshore	-	3	8	4.83	-	5.25	-	18	91	49.99	-	50.41
Atlantic Coast Offshore	-	2	4	2.99	-	4.84	-	5	14	10.40	-	16.64
TOTAL UNITED STATES OFFSHORE	-	10	49	26.14	-	38.45	-	42	181	102.87	-	133.40

Modification of Resource Estimates: Having selected the USGS Resource Appraisal Group estimates as most appropriate for this study, some modifications and interpretations are still necessary if the data are to be useful within the context of our research methodology. Three, somewhat diverse issues, are important -- the question of conditional versus unconditional distributions, the partitioning of resource estimates between oil and non-associated natural gas fields, and regional groupings to be used for our subsequent analysis.

Conditional Distributions: The distributions displayed in Table 1 are unconditional distributions and the means of the distributions represent the true expected value of recoverable hydrocarbons. In a probability sense, the distributions represent the intersection of the probability distributions of recoverable hydrocarbons and the probability of finding hydrocarbons. However, the economic model, to be formulated in Chapter IV, utilizes a probability distribution conditional upon success in finding oil. In other words, it utilizes the distribution of expectations on reserve size given that oil is found.[5] The conditional mean value is determined by dividing the mean values in Table 1 by the marginal probabilities of finding oil.[6]

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[5]Utilizing Bayes theorem, the conditional probability is found according to the following formula:

$$P(O|S) = \frac{P(O \cap S)}{P(S)} \tag{1}$$

$P(O)$ = probability distribution for oil
$P(S)$ = probability of success
$P(O|S)$ = probability distribution of oil given success
$P(O \cap S)$ = intersection of probability distribution for oil and for success

Although the theorem is usually applied to events with discrete probabilities, the probability distribution for oil may be utilized in this case because only the mean of the distribution is needed.

[6]Because the marginal probabilities (MP) are in the form of a decimal fraction between 0.0 and 1.0 and represent the probability that commercial oil or natural gas will be discovered within a geologic province, the value 1.0-MP is the probability that no commercial oil or natural gas will be discovered. The economic model utilizes a dry-tract risk factor for the development analysis. This input parameter represents the chance that no resource will be discovered on the tract.

If we assume that the marginal probability for the entire province is also a reasonable approximation for the probability of a resource find on a specific tract, then the value 1.0-MP is a reasonable approximation for the dry-tract risk factor in the economic model. This assumption has been incorporated into this study with the realization that the probabiiity of a dry tract will not be uniform throughout an entire geologic province or subregion. Also, intuitively, it seems that when considering a specific tract in a province with a MP equal to 1.0, the risk of a dry tract will be greater than 0.0 (which would be used in the model). However, it should be emphasized that the

Partitioning of Resource Estimates: For an appropriate economic analysis of oil and non-associated natural gas fields, a partitioning of estimated resources between these field types is required.[7] To do this, two assumptions were made.

First, using historical production data for associated and non-associated gas production (NPC, 1973), the assumption was made that twenty percent of the total natural gas (GTOT) estimate in each province was associated gas (GASS) and eighty percent was non-associated gas (GNASS). Second, .033 barrels of natural gas liquid (NGL) was assumed produced for each Mcf of natural gas production. This factor is the national NGL-to-gas ratio utilized in USGS Circular 725. It is somewhat higher than the offshore average of .025 assumed in the same publication. However, the larger national average was utilized in this study.[8]

Utilizing the two assumptions described above, the following calculations were made. First, the total amount of natural gas liquids produced from non-associated gas fields (NGLNASS) was obtained by multiplying the natural gas liquid yield factor of .033 barrels per Mcf by the total amount of non-associated gas (GNASS):

(2) $$NGLNASS = .033\ (0.8\ GTOT)$$

Second, the total amount of liquid hydrocarbons in oil fields (LIQASS), i.e., the sum of oil (OIL) plus natural gas liquid yield from associated gas production (NGLASS), is obtained by subtracting the natural gas liquids in

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marginal probabilities subjectively reflect the amounts of geologic knowledge available for the areas and, thus, give relative differences in the expectations of success or failure between the various provinces and subregions. Because these marginal probability values can be subjectively interpreted as being measures of relative risks across various provinces, and because no other risk estimates were available, these factors were utilized in the policy analysis.

[7]Non-associated natural gas fields are defined as those in which the primary resource is natural gas, or gas and condensate (natural gas liquids). Similarly, oil reservoirs are defined as those in which the primary resource is petroleum which can be produced with natural gas (associated gas) and condensate.

[8]The Bureau of Land Management (BLM) Technical Bulletin 5 (p. 146) documents increases in NGL-to-gas ratios for both non-associated and associated gas during the years 1947-1967. In 1967, the NGL-to-non-associated gas ratio was .025 and the NGL-to-associated gas ratio was .045, the NGL/total gas ratio being .029. Assuming a continued increase in the OCS NGL-to-gas ratio and realizing the uncertainties in projecting these ratios throughout the various geographic locations of frontier OCS regions, the national NGL-to-gas ratio was assumed for all provinces under consideration.

non-associated gas fields (NGLNASS) from the estimates of total liquid hydrocarbons (LIQTOT) for each province:

(3) LIQASS = OIL + NGLASS = LIQTOT − NGLNASS = LIQTOT − 0.33 (.8 GASTOT)

Third, with the approximations for associated gas (GASASS) and total liquid hydrocarbons contained in oil fields (LIQASS), an associated gas-to-liquids ratio (AGFAC) was computed for each province:

(4) AGFAC = GASASS/LIQASS

These results, then, gave the amount of undiscovered hydrocarbon liquids (oil and NGL) contained in oil fields, the amount of NGL in non-associated gas fields, and the amount of undiscovered natural gas contained in non-associated gas fields. Also, the associated natural gas present in oil fields can be computed by using the associated gas to liquid hydrocarbon ratios.

Regional Aggregation: Upon reviewing the twenty-eight USGS offshore provinces in the context of proximity, geography and geologic analog used to estimate field size distributions (see next section), it was decided to group a number of the provinces together to form thirteen subregions. This was feasible because of the similarities which existed between individual members of the original taxonomy, both with respect to geology and production costs (see Chapter 5), and was done in order to reduce analytical costs (principally computer time). Figures 5 and 6 display the results of this aggregation.

The thirteen subregions and the USGS provinces which comprise them are also listed in Table 2. In addition, the sums of the conditional mean resource estimates for undiscovered recoverable oil and natural gas in the subregions are listed,[9] along with associated gas/oil ratios.

Field Size Distributions: Because the economics of energy resource development vary markedly according to the amount of developable resource contained within an oil or natural gas field, it is essential that information be obtained as to how the hydrocarbons may be distributed according to field size. A number of studies have demonstrated empirically that the size distributions of oil fields have an approximate lognormal form (Arps and Roberts, 1958; Kaufman, 1962; McCrossam, 1969). This means that many of the fields in a region may be too small to develop, but that a large percentage of the hydrocarbon resources may be trapped in relatively large-sized fields (which will be economically producible).[10] Hence, the nature of the field size

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[9] Although the provinces combined to form the subregions were geographically contiguous, the provincial marginal probabilities were not always equal throughout. For these cases, a weighted average of the marginal probabilities was calculated using the mean undiscovered recoverable resource estimates as weights. These revised marginal probabilities are also shown in Table 2.

[10] According to an Office of Technology Assessment study, seventy-five percent of the reserves found in the United States have been in fields of fifty million barrels or larger (OTA, 1975, pp. 19-22).

Figure 5.--Aggregated OCS Provinces Surrounding the Conterminous Lower 48 United States

Figure 6.--Aggregated OCS Provinces Surrounding Alaska

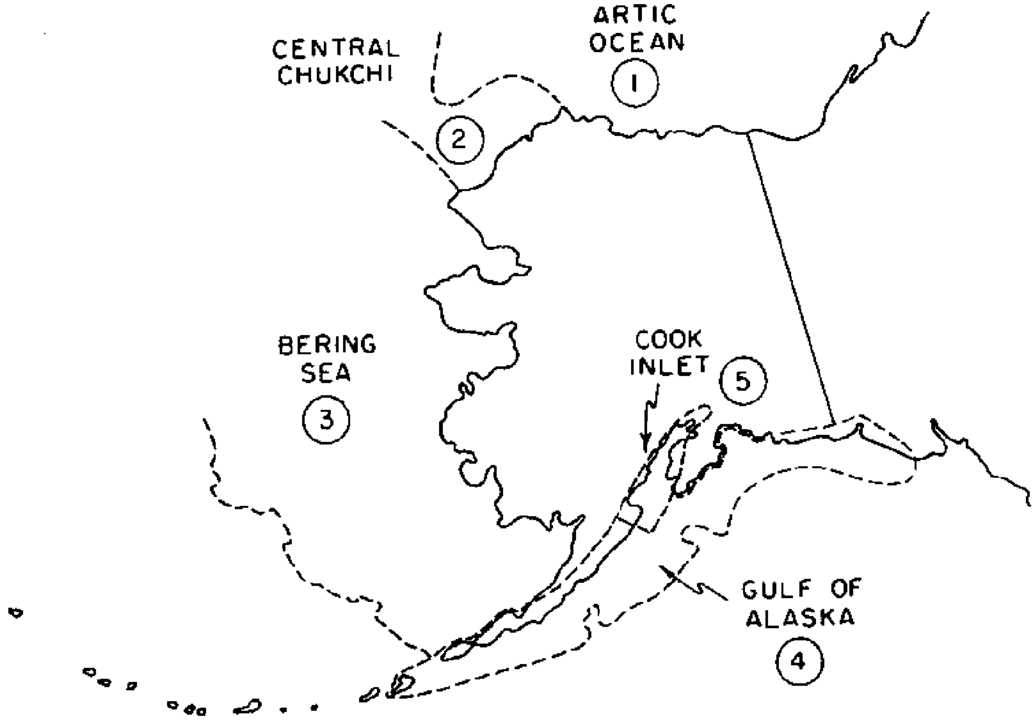

Table 2.--Revised Groupings of Geologic Provinces, Associated Resource Estimates, and Marginal Probabilities

Subregions Analyzed in this Study	USGS Provinces Included in Subregions	Unconditional Undiscovered Recoverable Hydrocarbon Estimates (Mean Values)				Revised Marginal Probability	Assoc. Gas/Oil Ratio $(\frac{Mcf}{Bbl})$
		Total Liquids	Liquids (Oil and NGL) in Oil Fields	Total Gas	Non-associated Gas		
		(Billion Barrels)		(Trillion Cubic Feet)			
1. Arctic Ocean	Beaufort Sea North Chukchi	7.52	6.98	20.38	16.31	.70	.584
2. Central Chukchi	Central Chukchi	6.30	5.89	15.71	12.57	.70	.534
3. Bering Sea	Hope Norton Zhemchug-St. George Bristol Navarin	7.04	6.61	16.12	12.89	.45*	.487
4. Gulf of Alaska	Eastern Gulf of Alaska Kodiak Shumagin Shelf	2.39	2.21	6.97	5.58	.64	.630
5. Cook Inlet	Cook Inlet	1.19	1.13	2.39	1.91	1.00	.426
6. North Pacific	Santa Maria Bodega Oregon-Washington	1.01	0.97	1.68	1.34	.42	.352
7. Santa Cruz	Santa Cruz	0.24	0.23	0.24	0.19	.50	.214
8. S. California	Inner Basins Outer Basins & Ridges Santa Barbara	2.67	2.59	2.86	2.29	.99	.220

Table 2.—Continued

Subregions Analyzed in this Study	USGS Provinces Included in Subregions	Unconditional Undiscovered Recoverable Hydrocarbon Estimates (Mean Values)				Revised Marginal Probability	Assoc. Gas/Oil Ratio $(\frac{Mcf}{Bbl})$
		Total Liquids	Liquids (Oil and NGL) in Oil Fields	Total Gas	Non-associated Gas		
		(Billion Barrels)		(Trillion Cubic Feet)			
9. Central and Western Gulf	Central and Western Continental Shelf	3.84	2.55	49.00	39.20	1.00	3.849
10. MAFLA	Florida Gulf Platform	1.41	1.37	1.41	1.13	.70	.204
11. North Atlantic	North Atlantic Shelf	1.48	1.28	7.40	5.92	.60	1.152
12. Central Atlantic	Central Atlantic Shelf	2.51	2.31	7.56	6.05	.70	.654
13. South Atlantic	South Atlantic Shelf	0.85	0.81	1.68	1.34	.40	.422

*For gas this value is .51.

distributions within offshore provinces will influence the development of these areas.

These distributions are, of course, impossible to determine in areas with little or no exploration and/or production histories. Even in well-developed petroleum basins it is difficult to assess the field size distributions with complete accuracy. However, utilizing historical records of exploration results in similar geologic areas can furnish a reasonable basis for making assumptions.

For example, the yearly issue of the Bulletin of the American Association of Petroleum Geologists devoted to "North American Developments" presents historical compilations of new field discoveries in the United States. For each year, the total number of new fields discovered is divided into six size classifications:

Field Class	Oil Field Size	Gas Field Size
A	over 50 million barrels	over 300 million Mcf
B	25 - 50 " "	150 - 300 " "
C	10 - 25 " "	60 - 150 " "
D	1 - 10 " "	6 - 60 " "
E	less than 1 million bbls.	less than 6 million Mcf
F	abandoned as non-profitable	abandoned as non-profitable

Figures 7 and 8 are graphs of the total numbers of oil and natural gas fields, respectively, in the size ranges A through F, which were discovered between 1945 and 1968. It is instructive to note the rapid decrease in field size as the number of fields discovered increases.

More detailed insight into the size distribution of oil fields is published in the National Petroleum Council's (NPC) report on oil and natural gas availability (National Petroleum Council, 1973). The NPC utilized a tabulation of crude oil reserves by field size for the period 1860-1944. These historical statistics were separated by region and geologic horizon. Field size data were plotted on lognormal probability paper and a straight line was fit to each province data set, corresponding to a particular lognormal probability distribution. Sufficient data to characterize each of these distributions are tabulated in Table 3. The mean field size for each distribution and the field sizes at plus and minus one log standard deviation (15.9 and 84.3 percent) are presented.

The AAPG data and NPC distributions represent alternative approaches which could be utilized in this study. One approach would be to assume that the field size distributions for each of the various offshore provinces are similar to the AAPG data for the entire United States depicted in Figures 7 and 8. Obviously, however, the field size distribution of each of the offshore provinces will differ, perhaps significantly, from these aggregated United

Figure 7.--Numbers of New Oil Field Discoveries of Various Sizes (1946-1968)

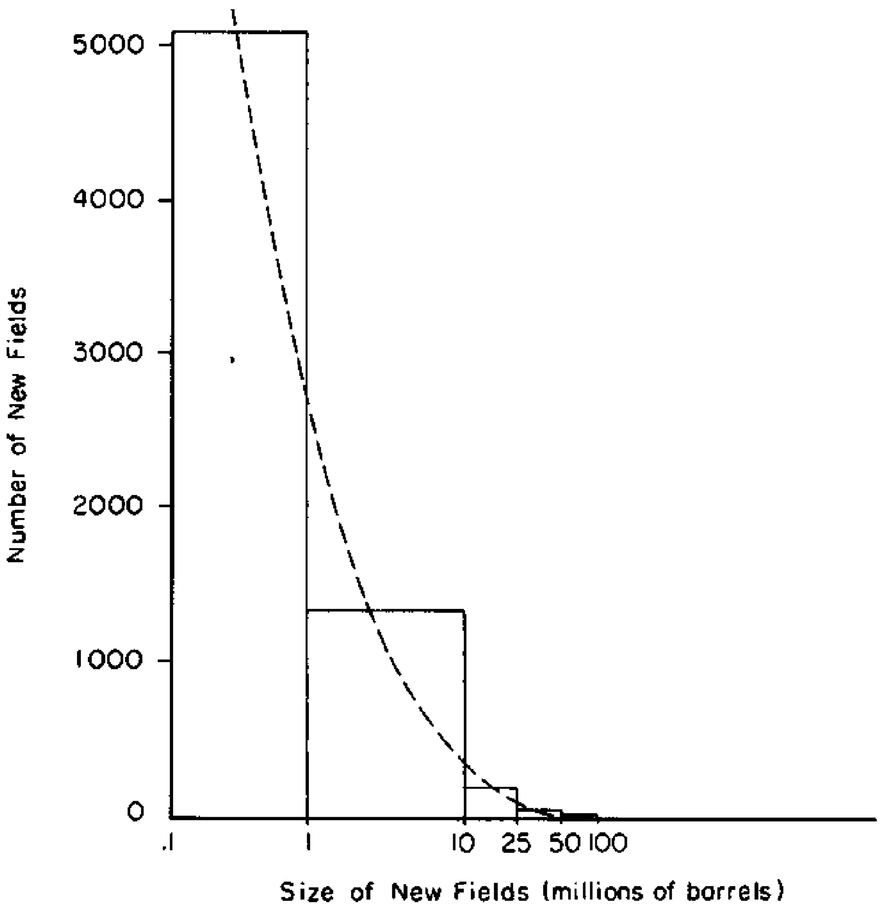

Figure 8.--Numbers of New Natural Gas Field Discoveries of Various Sizes (1946-1968)

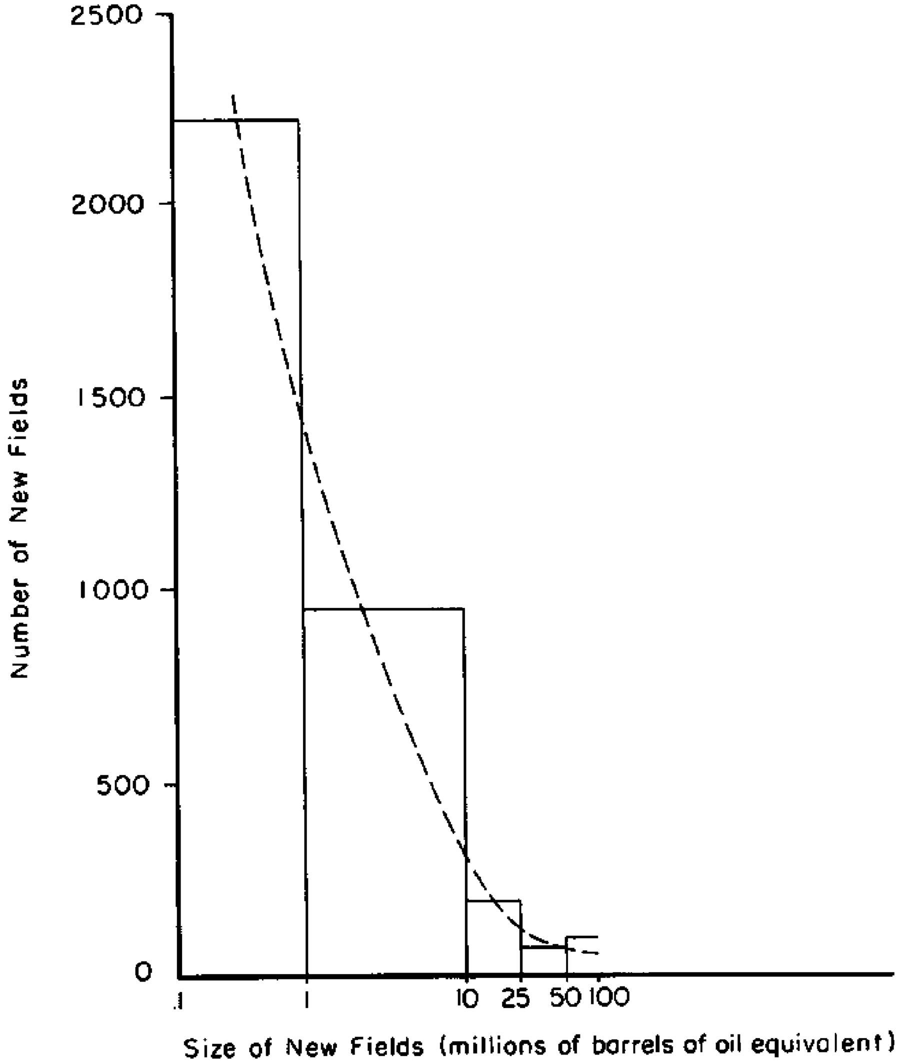

Table 3.--Oil Field Size: Lognormal Distribution for Various Percentiles

Geologic Province	Geologic Horizon	Pool Size at Percentile — Millions of Barrels of Primary Reserves		
		15.9%	50.0%	84.3%
Coastal/Santa Maria Valley	Pliocene/Upper Miocene	0.33	7.20	154.00
Los Angeles Basin	Pliocene/Upper Miocene	3.20	20.50	136.00
San Joaquin Valley	Pliocene/Upper Miocene	0.66	11.30	190.00
	Middle Miocene	0.63	8.40	112.00
	Lower Miocene	0.16	6.15	66.00
	Eocene and Older	0.19	4.10	90.00
Ventura Basin	Pliocene/Upper Miocene	0.53	3.14	18.20
	Middle/Lower Miocene	0.07	1.83	51.00
	Oligocene and Older	1.18	6.80	39.00
Green River	Mesozoic	0.28	2.98	34.50
No. Rocky Mountains (excl. Green River)	Mesozoic	0.18	1.90	21.00
No. Rocky Mountains Composite	Permo-Pennsylvanian	0.30	3.60	43.00
	Pre-Pennsylvanian	0.39	3.25	27.80
Midland Basin/Eastern Shelf	Guadalupe	0.01	0.43	17.00
Northwest Shelf	Guadalupe	0.11	2.50	66.00
Central Basin Platform, Delaware and Diablo Basin Composite	Guadalupe	0.87	7.20	61.50
New Mexico/West Texas Composite	Lower Permian	0.03	0.48	8.60
	Cisco/Canyon/Strawn	0.13	0.80	5.00
	Lower Pennsylvanian	0.06	0.58	7.30
	Mississippian	0.33	0.77	1.85
	Ordovician	0.10	1.60	28.00
Gulf Coast	Pleistocene/Pliocene/ Upper Miocene	1.24	9.30	71.50
	Miocene	0.82	5.60	38.00
	Oligocene 0-5000'	0.45	1.48	15.10
	Oligocene 5000-15,000'	0.43	3.65	31.00
	Eocene	0.17	1.48	12.60
	Cretaceous	0.23	3.25	45.50
	Jurassic	0.24	4.20	72.00
	Pre-Jurassic[a]	0.02	0.21	2.30

Table 3.--Continued

Geologic Province	Geologic Horizon	Pool Size at Percentile: Millions of Barrels of Primary Reserves 15.9%	50.0%	84.3%
Midcontinent	Cretaceous[b]	0.23	3.25	45.50
	Permian	0.03	0.48	8.60
	Pennsylvanian	0.04	0.47	5.00
	Mississippian	0.02	0.23	2.90
	Devonian-Silurian	0.04	0.16	0.62
	Upper Middle Ordovician	0.04	0.43	4.45
	Lower Middle Ordovician	0.10	0.92	8.30
	Lower Ordovician	0.02	0.16	1.90
Michigan Basin	Middle Devonian-Silurian	0.06	0.80	11.20
	Middle Ordovician	0.04	0.43	4.45
Eastern Interior	Mississippian	0.02	0.21	2.30
	Lower Mississippian	0.01	0.11	0.87
	Middle, Lower Devonian/ Silurian	0.06	0.80	11.20
	Upper, Middle Ordovician[c]	0.04	0.43	4.45
	Cambrian-Ordovician	0.02	0.16	1.90
Appalachian	Lower Mississippian	0.68	2.82	11.00
	Devonian-Silurian	1.16	4.95	21.10
	Middle Ordovician	0.04	0.43	4.45
	Cambrian-Ordovician	0.02	0.16	1.90
Atlantic Coast	Cretaceous[d]	0.23	3.25	45.50
	Jurassic and Older[d]	0.24	4.20	72.00

[a]Eastern Interior Basin Composite Mississippian data (closest geologically related information)

[b]Gulf Coast Cretaceous (closest geologically related information)

[c]Midcontnnent Upper Middle Ordovician (closest geologically related information)

[d]Gulf Coast data used (closest similar geologic information)

Source: National Petroleum Council, 1973, p. 182.

States field size distributions. For this reason, it was decided that the NPC field size statistics would be more appropriate.[11]

However, because the offshore areas considered in this study are not included in the statistics shown in Table 3, geologic analogies had to be established between the offshore provinces under study and the geologic provinces for which field size data are available. Fortunately, such analogies were included in the Province Summary Sheets and the Resource Appraisal Province Estimate sheets which are part of the Basic Files for USGS Circular 725 housed in Denver. The analogs consist of judgements by the province evaluators as to which known geologic provinces are analogous to the area for which the resource estimates were being made. The analogs proposed by the province evaluators for each of the OCS provinces are listed in Table 4. In comparing Tables 3 and 4, it is evident that a number of the analogs proposed by the USGS evaluators are not included in the NPC field size distributions. Thus, for some offshore provinces, a further judgement was required to draw an analogy with one of the NPC provinces. Also listed in Table 4 are the NPC geologic provinces which were used as analogs for the offshore provinces included in this study. These analogs, then, serve as the basis for our estimates of offshore field size distributions in each of the thirteen subregions.

Estimation Procedures: Use of the NPC analogs to determine field size distributions for each offshore subregion involves some difficult problems of interpretation. As mentioned above, the analog field size distributions were created by fitting theoretical lognormal distributions to observed field size data in various United States geological provinces. In every case the potential range of the resulting theoretical distributions is much greater than the data actually used in creating the distributions. For example, if one of the theoretical distributions were repeatedly random sampled, the range of sample values would be from very near zero to billions of barrels of oil, whereas the range of the historical data actually used in creating the distribution would be much narrower. Hence, although the theoretical lognormal distributions provided a good fit of observed data within and near the range of observed historical data, extrapolation to the tails of the distributions produced results which were neither valid nor meaningful.

To correct this deficiency, we attempted to determine appropriate criteria for truncating the theoretical lognormal distributions to make them statistically valid and useful for this analysis. On the lower end, we set out to determine the minimum field sizes which <u>were considered</u> by the geologists who formulated the USGS Province resource estimates. As mentioned above, the USGS report states that the estimates were done assuming continuation of

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[11]Although many of the same kinds of hydrocarbon generation, migration and trapping processes are involved in the formation of oil and natural gas fields, some aspects of gas accumulation differ significantly from those for oil. With this in mind, but also with the realization that so little is known about the geology of the offshore provinces, the assumption was made that the <u>forms</u> of the field size distributions were the same for both resources.

Table 4.--Subregions, Geologic Provinces, and Basin Analogs

Subregions Analyzed in this Study	United States Geological Survey Geological Province	United States Geological Survey Evaluator's Basin Analog	National Petroleum Council Analog Used in this Study
1. Arctic Ocean	Beaufort Sea	Clastic and non-diapiric parts of Gulf Coast, no pre-Cretaceous; E. North Slope	Gulf Coast Oligocene 5,000'-15,000'
	North Chukchi	Gulf Coast U.S. (but no salt and perhaps no prospective pre-Cretaceous)	Gulf Coast Oligocene 5,000'-15,000'
2. Central Chukchi	Central Chukchi	Western North Slope; Western Interior U.S. and Canada	Northern Rockies-Mesozoic
3. Bering Sea	Hope	Anadyr (USSR); Cook Inlet (without Jurassic-Cretaceous marine rocks)	Ventura Basin
	Norton	Cook Inlet; Anadyr (USSR); Deltaic Basin (Niger)	Ventura Basin
	St. Matthew-Hall	Not Included in Analysis - Resources Estimated to be Negligible	
	Bristol	Cook Inlet (offshore); Norton Basin	Ventura Basin
	Navarin	Possibly Anadyr (USSR)	Ventura Basin
	Zhemchug-St. George	Anadyr (USSR)? Cook Inlet?	Ventura Basin
4. Gulf of Alaska	Eastern Gulf of Alaska	Oregon-Washington offshore and B.C.	Santa Maria Basin
	Kodiak Tertiary	Oregon-Washington offshore	Santa Maria Basin
	Shumagin Shelf	Southern California Borderlands	Santa Maria Basin
5. Cook Inlet	Cook Inlet	Ventura Basin; Uinta Basin	Ventura Basin
6. North Pacific	Santa Maria	Santa Maria Basin (onshore)	Santa Maria Basin
	Bodega	Santa Maria Basin (onshore), Ventura Basin	Santa Maria Basin
	Pt. Arena	Not Included in Analysis - Resources Estimated to be Negligible	
	Eel River	Not Included in Analysis - Resources Estimated to be Negligible	
	Oregon-Washington	Gulf of Alaska; Northern California	Santa Maria Basin

Table 4.—Continued

Subregions Analyzed in this Study	United States Geological Survey Geological Province	United States Geological Survey Evaluator's Basin Analog	National Petroleum Council Analog Used in this Study
7. Santa Cruz	Santa Cruz	Ventura Basin; Santa Maria Basin (onshore)	Ventura Basin
8. Southern California	Inner Basins	Los Angeles Basin	Los Angeles Basin
	Outer Basins and Ridges	Santa Maria Basin (onshore); Los Angeles Basin	Los Angeles Basin
	Santa Barbara Channel	Los Angeles Basin; Santa Maria Basin (onshore)	Los Angeles Basin
9. Central and Western Gulf	C. & W. Continental Shelf	Gulf of Mexico	Gulf Coast Oligocene 5,000'-15,000'
10. MAFLA	Florida Gulf Platform	Smakover Trend (Jurassic) Gulf Coast	Gulf Coast-Jurassic
11. North Atlantic	North Atlantic Shelf	Scotian Shelf; Mesozoic Trend in Gulf Coast Area	Gulf Coast-Jurassic
12. Central Atlantic	Central Atlantic Shelf	Permian Basin; Smakover Trend (Jurassic) Gulf Coast; Scotian Shelf	Gulf Coast-Jurassic
13. South Atlantic	South Atlantic Shelf	W. Florida Platform; Penninsular Florida	Gulf Coast-Cretaceous
	Southeast Florida Shelf and Straits	Not Included in Analysis - Resources Estimated to be Negligible	

pre-1974 price-cost relationships (Miller, et al., 1975, p. 1). On a province by province basis, we polled a number of geologists attempting to determine what were the minimum field sizes considered to be commercially developable (given the pre-1974 economics assumption) and, therefore, included in the total resource estimate.[12] While it was difficult to obtain definitive statements from many of those consulted, a range of figures regarding minimum commercial field size by province did emerge from the numerous discussions.

On the basis of these discussions, minimum field sizes applicable to the twenty-eight original USGS geologic provinces were estimated. These values are summarized in Table 5. In all cases, we have used an estimate from the lower end of the ranges obtained from the geological experts. The rationale for this decision was directly related to the influence of changing economics on the minimum field size values. Since our subsequent economic analysis will use post-1973 price-cost relationships, consistency requires the use of such relationships in defining the cutoff point on the USGS distributions. By using the lower end of the ranges of the subjective values obtained for minimum field sizes, a better approximation of current relationships could be obtained. In addition, a comparison was made between results using the lower and upper ends of the ranges and the distribution of field sizes changed by less than five percent. Thus, the results do not appear overly sensitive to the judgements made.

The subjective interpretations of minimum field sizes were then applied to the estimated resource distributions for each of the thirteen offshore subregions under consideration (note that the minimum field sizes for all aggregated provinces were identical). Hence, this process assumes that all of the estimated undiscovered recoverable resources are trapped in fields larger than the minimum developable field size.

Statistical considerations also required that a maximum field size cutoff be applied to the distributions (Kaufman, et al., 1975). Because the parameters for the lognormal distributions were available and not the specific historical field size data, an assumption had to be made concerning the maximum field size expected to be discovered in each geologic subregion. After testing various alternatives, this maximum cutoff was established as the point at two log-standard deviations beyond the mean for each particular distribution. This value appeared reasonable in that the distribution of oil by field size category generally approached the historical distributions for the United States.

The truncated lognormal field size distribution for each subregion could now be used to determine mean field sizes and, in conjunction with our mean

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[12] Among those contacted were Betty Miller and Gordon Doltan, USGS, Denver; W. T. Perry, Jr. and Larry Drew, USGS, Reston; Rod Pearcey, USGS, New Orleans; Sid Kaufman and William B. Travers, Cornell University; plus a number of individuals from the commercial sector, most of whom requested that their identity and specific comments be kept off the record.

Table 5.--Estimates of Pre-1974 Minimum Developable Hydrocarbon Field Sizes for Each of the Offshore Geologic Provinces

Province	Minimum Developable Field Sizes	
	Oil	Gas
	(Million Barrels)	(Million Mcf)
Beaufort Sea	12.5	75.0
North Chukchi	12.5	75.0
Central Chukchi	12.5	75.0
Hope	10.0	60.0
Norton	10.0	60.0
St. Matthew-Hall	10.0	60.0
Bristol	10.0	60.0
Navarin	10.0	60.0
Zhemchug-St. George	10.0	60.0
Cook Inlet	5.0	30.0
Eastern Gulf of Alaska	10.0	60.0
Kodiak Tertiary	10.0	60.0
Shumagin Shelf	10.0	60.0
S. California-Inner Basins	2.5	15.0
S. California-Outer Basins and Ridges	2.5	15.0
Santa Barbara Channel	2.5	15.0
Santa Cruz	4.0	24.0
Santa Maria	4.0	24.0
Bodega	4.0	24.0
Pt. Arena	4.0	24.0
Eel River	4.0	24.0
Oregon-Washington	4.0	24.0
Florida Gulf Platform	1.5	9.0
C. and W. Continental Shelf	1.5	9.0
North Atlantic Shelf	5.0	30.0
Central Atlantic Shelf	2.5	15.0
South Atlantic Shelf	1.5	9.0
Southeast Florida Shelf and Straits	1.5	9.0

resource estimates (Table 2), to estimate the number of fields by size category. In addition, an estimate of the standard deviation of field sizes for each region must be made. Derivation of these three factors will be outlined below.

Mean Field Sizes by Field Size Group: Mean field sizes were developed by randomly sampling each field size distribution until one thousand fields larger than the minimum developable field and smaller than the maximum cutoff size were obtained. These fields were then grouped into the following size categories:

Category 1 -- Minimum field size to fifty million barrels for oil and to three hundred million Mcf for natural gas,

Category 2 -- Fifty to one hundred million barrels for oil and three hundred to six hundred million Mcf for natural gas, and

Category 3 -- Greater than one hundred million barrels for oil and greater than six hundred million Mcf for natural gas.

For each of the three categories, the mean field size and proportion of total resource (per subregion) expected in each field size category were calculated. Table 6 displays the results for oil and Table 7 for non-associated natural gas.

Standard Deviation of Field Sizes: The standard deviation of each field size category (for each subregion), along with the field size means, forms the basis for our subsequent Monte Carlo simulation of the reserve value used as input to the economic analysis.

Subjective judgements were made for this purpose, incorporating the following considerations:

1. It is important to distinguish between ex ante expectation (belief) distributions and ex post distributions of actual field size. The analogs used in this process represent actual (ex post) distributions of discovered oil field sizes. When these distributions are partitioned into three field size classes, each class distribution represents an ex post view of the distribution of oil field sizes within each category. Yet, it is the distribution of ex ante beliefs which we are seeking to determine.

This process assumes that geologists generally are able to classify their expectations of a given area as having potential for a small, medium, or large find (or no find). If we assume that the mean sizes of expected small, medium, and large finds correspond to the mean sizes of the three field size categories described above, we then need only to estimate the variance (standard deviation) of each distribution. Clearly, the variance of the ex post distributions (from the partitioned lognormal analogs) described above, alone, is not a good basis for determining the ex ante distribution variance of beliefs on oil discovery. There is no assurance that the variance of an historical set of "small" field discoveries will correspond to expectations of a small find in a given province. The parameters of these "belief" distributions (u,σ^2) must be subjective judgements and cannot be statistically

Table 6.--Oil Field Sizes, Standard Deviations and Percent of Total Resource by Field Category and Subregion

Subregion	Category 1 Fields (less than 50 mil. bbls.)			Category 2 Fields (50-100 mil. bbls.)			Category 3 Fields (greater than 100 mil. bbls.)		
	Mean (mil. bbls.)	Std. Dev. (mil. bbls.)	% of Total Resource	Mean (mil. bbls.)	Std. Dev. (mil. bbls.)	% of Total Resource	Mean (mil. bbls.)	Std. Dev. (mil. bbls.)	% of Total Resource
1. Arctic Ocean	25.8	12.9	30	70.0	49.0	28	158.7	158.7	42
2. Central Chukchi	25.9	12.9	33	69.6	48.7	26	147.3	147.3	41
3. Bering Sea	23.0	11.5	37	69.8	48.9	32	147.4	147.4	31
4. Gulf of Alaska	23.9	11.9	4	73.1	51.2	4	577.9	577.9	92
5. Cook Inlet	17.4	8.7	43	69.9	48.9	29	145.2	145.2	29
6. North Pacific	17.4	8.7	5	73.9	51.7	5	567.9	567.9	91
7. Santa Cruz	16.2	8.1	43	70.1	49.1	29	144.9	144.9	28
8. S. Cal. Basins	17.2	8.6	14	71.9	50.3	11	256.6	256.6	75
9. C. and W. Gulf	11.7	5.8	40	70.0	49.0	26	155.8	155.8	33
10. MAFLA	12.8	6.4	12	70.8	49.6	9	311.8	311.8	79
11. North Atlantic	18.5	9.2	11	70.2	49.1	8	321.3	321.3	81
12. Central Atlantic	15.0	7.5	12	71.0	49.7	8	320.6	320.6	80
13. South Atlantic	12.2	6.1	21	70.9	49.6	15	225.7	225.7	65

Table 7.--Non-Associated Natural Gas Field Sizes, Standard Deviations and Percent of Total Resource by Field Category and Subregion

Subregion	Category 1 Fields (less than 300 mil. Mcf)			Category 2 Fields (300-600 mil. Mcf)			Category 3 Fields (greater than 600 mil. Mcf)		
	Mean (mil. Mcf)	Std. Dev. (mil. Mcf)	% of Total Resource	Mean (mil. Mcf)	Std. Dev. (mil. Mcf)	% of Total Resource	Mean (mil. Mcf)	Std. Dev. (mil. Mcf)	% of Total Resource
1. Arctic Ocean	154.8	77.4	30	420.0	294.0	28	952.2	952.2	42
2. Central Chukchi	155.4	77.7	33	417.6	292.3	26	883.8	883.8	41
3. Bering Sea	138.0	69.0	37	418.8	293.2	32	884.4	884.4	31
4. Gulf of Alaska	143.4	71.7	4	438.6	307.0	4	3,467.4	3,467.4	92
5. Cook Inlet	104.4	52.2	43	419.4	293.6	29	871.2	871.2	29
6. North Pacific	104.4	52.2	5	443.4	310.4	5	3,407.4	3,407.4	91
7. Santa Cruz	97.2	48.6	43	420.6	294.4	29	869.4	869.4	28
8. S. Cal. Basins	103.2	51.6	14	431.4	302.0	11	1,539.6	1,539.6	75
9. C. and W. Gulf	70.2	35.1	40	420.0	294.0	26	934.8	934.8	33
10. MAFLA	76.8	38.4	12	424.8	297.4	9	1,870.8	1,870.8	79
11. North Atlantic	111.0	55.5	11	421.2	294.8	8	1,927.8	1,927.8	81
12. Central Atlantic	90.0	45.0	12	426.0	298.2	8	1,923.6	1,923.6	80
13. South Atlantic	73.2	36.6	21	425.4	297.8	15	1,354.2	1,354.2	65

derived. All the information currently available is used in specifying that judgement.

2. The standard deviation to mean ratios for the USGS province resource estimates ranged in value from 0.01 to 1.76, with but two provinces having ratios greater than 1.00. Although these ratios are indicative of wide ranges in expected variance in the province resource estimates, it is difficult to apply these data directly to variance expectations for field size distributions.

3. Standard deviation to mean ratios for expectations of small fields will probably be smaller than for the larger field categories used in this analysis. The narrower range of field sizes contained in the two smaller categories, when compared to the open-ended upper boundary for category three, greatly limit the field size variance in the first two categories. On the other hand, the shapes of the lognormal field size distribution curves for the various subregions tend to be the principal control on variance as well as mean field size for the category three fields.

4. It might be expected that after a period of extensive exploration, drilling and production within individual provinces, the expected field size variances would decrease in accordance with an increase in knowledge of the geological characteristics of the province. However, the expected mean field sizes for the region would undoubtedly also be revised as more geological knowledge is analyzed. These two factors, of unknown importance, are not applied to the present analysis. The assumption is made that the standard deviations and mean field sizes for each of the categories do not vary over the exploration time horizon.

With the above criteria in mind, the following somewhat arbitrary, but best-guess, standard deviation to mean field size ratios (σ/μ) were applied to the different field size categories: for small (category 1) fields, $\sigma/\mu = 0.5$; for medium (category 2) fields, $\sigma/\mu = 0.7$; for large (category 3) fields, $\sigma/\mu = 1.0$. The results of this application are also displayed in Tables 6 and 7.

Numbers of Fields by Size Category: Next, the total number of fields expected in each size category and subregion was calculated. The conditional mean resource estimate for each subregion (Table 2) was multiplied by the proportion of the total resource expected to occur in each field size category. The resulting values (the amount of oil or natural gas in each field category) were then divided by the expected mean field size for each category. The result was the number of fields of each size expected in each subregion. Table 8 displays the expected numbers of fields of each size for oil and non-associated natural gas, respectively, for the OCS subregions of the United States.

Order of Field Discovery: An assumption regarding the rates at which hydrocarbon fields will be discovered during exploration in each subregion is also needed to complete our subsequent analysis. The discovery rate serves as the basis for the time profiles of production and income streams under any given leasing schedule. Based upon empirical analyses of discovery rates in known producing regions (Drew, 1974; Kaufman, 1965; Arps and Roberts, 1958), several researchers have attempted to describe or model the discovery process.

Table 8.--Estimated Number of United States OCS Hydrocarbon Fields by Size Category

Subregion	Oil						Gas					
	Category 1 Fields		Category 2 Fields		Category 3 Fields		Category 1 Fields		Category 2 Fields		Category 3 Fields	
	No. of Fields	Mean Size (mil. bbls.)	No. of Fields	Mean Size (mil. bbls.)	No. of Fields	Mean Size (mil. bbls.)	No. of Fields	Mean Size (mil. Mcf)	No. of Fields	Mean Size (mil. Mcf)	No. of Fields	Mean Size (mil. Mcf)
1. Arctic Ocean	80	25.8	27	70.0	18	158.7	31	154.8	10	420.0	7	952.2
2. Central Chukchi	75	25.9	21	69.6	17	147.3	26	155.4	7	417.6	6	883.8
3. Bering Sea	106	23.0	30	69.8	14	147.4	34	138.0	9	418.8	5	884.4
4. Gulf of Alaska	3	23.9	1	73.1	3	577.9	1	143.4	1	438.6	1	3,467.4
5. Cook Inlet	27	17.4	4	69.9	3	145.2	7	104.4	2	419.4	1	871.2
6. North Pacific	2	17.4	1	73.9	1	567.9	0	104.4	0	443.4	1	3,407.4
7. Santa Cruz	6	16.2	1	70.1	1	144.9	1	97.2	1	420.6	0	869.4
8. S. Cal. Basins	20	17.2	4	71.9	7	256.6	3	103.2	0	431.4	1	1,539.6
9. C. and W. Gulf	88	11.7	10	70.0	6	155.8	225	70.2	24	420.0	14	934.8
10. MAFLA	13	12.8	1	70.8	3	311.8	1	76.8	0	424.8	1	1,870.8
11. North Atlantic	7	18.5	1	70.2	3	321.3	5	111.0	1	421.2	2	1,927.8
12. Central Atlantic	18	15.0	2	71.0	5	320.6	8	90.0	1	426.0	2	1,923.6
13. South Atlantic	13	12.2	1	70.9	3	225.7	3	73.2	0	425.4	1	1,354.2

This research has found that field size discovery may be modeled as sampling without replacement, with the probability of discovery of an individual field proportional to its size in relation to the remaining resources in undiscovered fields (see Kaufman, 1975 for a detailed discussion of this assumption). Using this assumption, one can expect the order of discovery of different field sizes within a region to be approximated by sampling from sets of field size distributions (Table 8) without replacement, with the discovery probabilities proportional to field size. It would be expected that large fields generally would be discovered early in the exploration time horizon. To implement this procedure, the following steps were taken:

1. The probability of selecting a field in a certain size category was assumed to be proportional to the percentage of the total resource calculated to be in that category within a subregion.

2. Using a random sampling procedure and the probabilities defined in (1) above, field sizes were sequentially selected. The mean of each selected field size was subtracted from the total resource figure and new probabilities were generated for each of the three field size categories before a new selection was made.

3. Sampling was continued until the resource was totally exhausted from each of the three field size categories.

A listing of the sampling order could then be interpreted as the order in which the fields are expected to be discovered.

It was then assumed that the rate of field discovery and the rate of OCS leasing could be equated. This assumption implies that "errors" in the leasing process, on average, tend to be offsetting and that the leasing sequence is a good proxy for the discovery sequence. Because leasing policies incorporate nomination of areas to be considered for leasing, the selection of OCS tracts which will be offered by the government is really a consequence of the exploration process. If we assume that the best prospects are nominated first by exploration companies, then these prospects will also be the first to be drilled and evaluated. Given that the selection of areas to be leased is part of the exploration process, it follows that it is part of the discovery process and that the leasing order can, at least roughly, be equated with the order of discovery.

Resource Discovery and Leasing Schedules: Completion of the discovery process described above would result in total discovery of <u>all</u> recoverable resources within an area. Because the leasing schedules considered subsequently are probably insufficient to exhaust the discovery process, only some portion of the recoverable resource would actually be found.[13] Consequently, for

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[13] Environmental withdrawals, national defense areas, and manpower or equipment constraints can all lead to this result.

analytical purposes, we assumed that seventy-five percent of the total undiscovered recoverable resource in any subregion would be discovered using the leasing schedules to be evaluated.[14] It should be noted that using this cutoff value, in conjunction with the random sampling process described above, results in the discovery of all or almost all of the large field sizes obtained from the field size distribution analysis.

Finally, for analytical purposes, the number of expected fields (by size category) corresponding to the seventy-five percent cutoff value was divided evenly into ten exploration units. In this format, leasing policy decisions such as concentration of leasing and exploration in particular areas can be more easily analyzed by increasing the number of exploration units assumed to be conducted within a given time increment. The total number of fields in all thirteen subregions which would be discovered in these ten exploration-effort units are displayed in Table 9, while tabulations for the individual subregions are included in Appendix A.

Summary: Having completed all of the steps described above, the following data were available for input to the economic model:

1. Expected numbers of undiscovered oil and natural gas fields of various sizes distributed throughout each of the thirteen offshore subregions of the United States (to water depths of 200 meters). These data are in the format of mean field size and standard deviation for each of three field size categories for each subregion (see Tables 6 and 7).

2. The order of and rate of leasing and discovery of the oil and natural gas fields within each subregion (see Appendix A).

To arrive at these values, we have tediously walked through a delicate web of data and assumptions. Despite the high degree of uncertainty in the resulting data, it appears to provide the best available basis for the analysis of alternative leasing systems and schedules, which is the purpose for which it is intended.

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[14] Leasing schedules varying from ten to twenty years in length will be simulated in Chapter 7.

Table 9.--Total Hydrocarbon Fields Discovered in Ten Exploration Effort Units (Assuming Discovery of 75 Percent of Total Reserves)

Exploration Effort Unit	Number Small Fields	Number Medium Fields	Number Large Fields
		Oil	
1	7	10	15
2	10	14	9
3	15	5	14
4	12	14	10
5	15	11	10
6	12	16	9
7	23	6	5
8	25	3	6
9	25	4	4
10	23	5	2
	Non-Associated Natural Gas		
1	8	4	9
2	6	11	6
3	11	4	8
4	13	5	7
5	17	4	5
6	18	6	2
7	13	8	2
8	20	2	1
9	18	4	1
10	16	5	1

Chapter III

Alternative OCS Leasing Systems

The basis for public management of OCS energy development is the leasing system used to initiate and govern private sector development.[15] In conjunction with leasing schedules (the rate and locations of potential OCS disposal), the leasing system is critical in determining government revenue, the rate and length of production from individual fields, production costs, and the return to the private developer. In this chapter, we discuss a variety of alternative systems which could be used in leasing OCS hydrocarbon resources. This discussion provides background information and sets the stage for our subsequent empirical evaluation of such systems (Chapter VI). The results of that evaluation will then be used in formulating the analysis of alternative leasing schedules.

Historically, the leasing system used by the United States for OCS areas is one which makes use of a cash bonus as the bid variable and assesses a fixed royalty on the value of production. During the last several years, however, there has been increasing interest in alternative systems with variations in both the bid variable and the rate at which the contingency factor (royalty or profit share rate) is assessed. This interest has culminated in the enactment by the United States Senate of the "Outer Continental Shelf Management Act of 1975" (S.521). That bill, and a complimentary version now under consideration by the House of Representatives, permits the use by federal resource managers of a number of new leasing options. In the following sections, we will review many of the leasing options which have been mentioned as alternatives to the current cash bonus approach (including options specified in S.521).

<u>Leasing Objectives</u>: To compare alternative leasing systems, a set of evaluation criteria is needed. The public leasing objectives stipulated by various enabling statutes are three in number.

1. To ensure an orderly and timely development of the resource in question;

2. To protect the environment; and

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[15]This statement assumes that the United States political system accepts the value judgement that such development should rest with the private sector. At this point, that proposition appears valid even though much debate has taken place over this issue. We will not evaluate the question further; for it is primarily a political question concerning perceptions of administrative feasibility and the impact that publicly run exploration and/or development would have on economic efficiency and equity. Such questions are beyond the scope of our inquiry. We will generally assume efficient development, and in the case of leasing to the private sector, competitive activity throughout our analysis.

3. To ensure the public a fair market value return on the disposition of its resources.[16]

The relative weights or trade-offs between the objectives are matters of subjective judgement which must be considered before establishing new or changed policies. For many, environmental protection should have a very heavy weight in leasing actions; while others are more concerned about revenue generation or public give aways to the private sector. Regardless of the manner in which leasing policy is conducted, some balancing of various social objectives is implicit. The degree of emphasis placed on the various outcomes will to a large extent determine the resultant policy mix.

The first objective, to ensure an orderly and timely development of the resource, is related to both the leasing schedule and leasing policy. Clearly, the location and timing of leasing activity is relevant to this objective, because it involves consideration of potential adverse regional impacts, possible manpower and equipment constraints, and the effects on capital availability brought about by the rate of OCS development. The choice of a leasing system is also related to this objective in that alternative systems result in differing initial capital requirements, and different timings of production and returns to the private sector investor. These effects are examined in more detail for the alternative systems in Chapter VI.

The second objective, to protect the environment, is related more to the schedule and location of lease sales than to the leasing system employed. Uniform administrative procedures, requirements, and environmental regulations can be imposed across all leasing systems in order to insure that environmental quality is maintained. Therefore, consideration of the environmental impacts of offshore leasing can only be evaluated within the context of leasing schedules, which are discussed in Chapter VI.

In this chapter, we turn our attention to the third objective, that of insuring the public a fair market return on the disposition of its resources. This objective is sometimes equated with maximizing government revenue although the two are not the same. The government could maximize its revenue by acting as a profit maximizing monopolist and constraining the rate of OCS leasing and development in order to increase revenues. However, for purposes of this analysis, we will assume that the government does offer leases at an adequate rate such that the fair market value objective may be thought of as maximizing government revenue within the context of obtaining the true competitive market value given adequate lease sales. Government revenue from oil leases is composed of bonus payments, royalty and/or profit share payments, and taxes. The impact of the leasing system on government revenue depends on the risk behavior of the leasing parties.

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[16] The Outer Continental Shelf Lands Act of 1953 (67 Stat. 462; 43 U.S.C. Secs. 133-1343) provides authority for offshore resource development. In addition, the Mining and Minerals Policy Act of 1970 (30 U.S.C. Sec. 21a) describes national minerals policy and Title 31 U.S.C. 483 obligates the Federal Government to obtain fair and equitable return on resource dispositions. Also, the National Environmental Policy Act of 1969 (42 U.S.C. 4321-47) details the environmental protection goals under which government action can take place.

Risk Behavior and Risk Sharing: Before proceeding, it may be beneficial to review possible combinations of risk behavior from both the government and private sector (bidders) point of view. Theoretically, there are six possible combinations of behavior with the public and private sector each capable of being risk averse, risk neutral, or risk loving. However, we will follow the customary practice of assuming the government (or public sector) is risk neutral and examine only the three remaining possibilities in further detail.

The simplest case is the situation where the private sector, as well as the public sector, is assumed to be risk neutral. In that event, the degree of risk sharing inherent in a lease system makes no difference because all parties are indifferent to varying degrees of risk. In this case, government revenue equals the sum of the residual lease value paid as a bonus, taxes, and contingency payments. Alternative leasing systems, then, can be compared on pure efficiency and equity criteria with no adjustments needed for risk behavior.

Another possibility is that private sector bidders are risk loving; that is, they prefer more risk to less. Assuming that the bonus bidding system is the simplest to administer, is efficient, and has no undesired side effects, the government would always choose a pure bonus system with no royalty or profit share provisions because its use would maximize government revenue. In other words, there would be disbenefits to the public sector from sharing risks with the private sector.

For the risk neutral and risk loving assumptions, none of the discussion on risk sharing in this chapter is relevant. However, the efficiency and equity aspects of the bonus system can still be evaluated. Although the conventional wisdom is that the cash bonus system is the most efficient, this "wisdom" will be treated as an hypothesis and examined empirically in Chapter VI.

The final possibility is that private sector bidders are risk averse (and the public sector risk neutral). This assumption is the most commonly employed and is the one to which our attention is directed in this chapter. With risk averse behavior the cash bonus payment represents only a fraction of the economic residual value. Because of the paucity of empirical analysis, it is impossible to measure the magnitude of the risk adjustment which might take place. However, we can evaluate differences in indicators of risk reduction without knowing their quantitative significance in terms of bonus reduction. If firms are risk averse, risk sharing (contingency) systems could turn out to be more efficient in achieving such objectives as maximizing government revenue or total production. (Hence, risk sharing is a tool to achieve other objectives, rather than an objective within itself.) The theoretical context for this analysis is developed in this chapter and the empirical results are outlined in Chapter VI.

In discussing alternative leasing systems, we will divide the possible systems into two groups: 1) those in which the cash bonus is the bid variable, and 2) those in which a contingency rate (royalty or profit share) is the bid variable. This distinction is not based on the share of contingency payments in total economic rent or total government revenue; rather, it is a classification of systems by bid variable.

Bonus Bid Systems: Before reviewing particular aspects of each leasing system using the bonus payment as the bid variable, it will be helpful to postulate a general theoretical structure of bonus bid information. It has been suggested that cash bonus bidding insures that the most efficient firm wins the bid because its costs are lower and hence the bid higher (Kaufman, 1970). However, an alternative hypothesis is that the firm with the most optimistic expectations regarding recoverable reserves becomes the winning bidder because of the significance of the expected reserve quantity in determining tract value (Capen, et al., 1971). In actuality, the winning bidder can be determined by the interplay of a number of factors such as the following:

1. Recoverable reserve expectations,

2. Future resource price expectations,

3. Production cost expectations,

4. The firm's time preference rate (discount rate),

5. The firm's risk preference function (the extent to which true expected value is changed due to varying degrees of risk, and

6. The firm's expectations on delays or constraints caused by equipment shortages, technical failure, and institutional problems such as environmental protection regulations.

The first three factors are the most important exogenous inputs used in calculating tract value. The discount rate (fourth factor) may vary among firms because of differences in access to the capital market, differences in opportunity cost among firms, or because of differences in demand for the hydrocarbons to be derived from the lease. Risk preference functions may vary among firms due to firm size or for a number of other reasons. A firm's expectations of recoverable reserves, prices, costs, the time profile of production, and other factors combine to produce a time stream of expected annual costs and revenues. This stream is then discounted to the lease sale date to determine the present value of the lease. In the competitive cash bonus bidding system, the firm which, considering all of these factors, views the prospect most favorably (highest value) becomes the winning bidder.

However, because of uncertainty in all of these factors, the actual expected lease value is adjusted by firms in determining bonus bids (assuming risk averse behavior). The certainty of a firm's estimate of tract value varies among tracts. For some tracts, reserves are known with some certainty (e.g., some Gulf drainage tracts), and for other tracts very little is known about recoverable reserves (e.g., the Atlantic OCS) and the variance in the reserve estimate is quite large. Varying degrees of uncertainty may also exist in other variables at other points in time or under different exploration and production conditions. The individual firm's response to varying degrees of risk is determined by its risk preference function. Assuming the firm is risk averse, it will tend to reduce its bids on riskier tracts (relative to true value) to compensate for the higher uncertainty.

In addition to the adjustment for risk, an adjustment for potential information bias must also be made. If the mean industry estimates and forecasts relating to the above factors are on average correct (or unbiased), the winning bidder would frequently be one that overestimates the potential value on a given tract. In other words, the winning bid would generally be too high given the future realized tract value, and the industry rate of return on competitive leases too low. Even though the average industry estimates may be unbiased, the estimate of the winning bidder would generally be more optimistic than the industry average; hence, the estimates of the winning bidders would tend to be biased. However, in the long run, if all bidders are aware of this tendency, and reduce their bids accordingly, the average winning bid would fall to the approximate mean expected tract value (despite the fact that the winning bidder would frequently still be the one that initially overestimates tract value). With historical experience, firms would learn how to adjust their bids to achieve this result. Any firm which did not reduce its bids to account for its potential information bias would achieve a lower rate of return and could eventually accumulate significant losses.

In addition to the adjustment for risk and information bias, an adjustment for the extent of anticipated competition must also be made. This adjustment involves game theory considerations with regard to the extent of anticipated competition and an analysis of prior bidding experience.

For the mathematically inclined, it may be helpful to represent the bid formation process symbolically. The anticipated annual net revenue stream is the difference between gross revenue and costs (B_t-C_t). Gross revenue is a function of the distribution of prices (P) and reserves (R) as shown in equation 5:

(5) $$B_t = f(P,R)$$

The anticipated annual cost stream is a function of the distribution of expected reserves, cost inputs (K), and other factors (Z) as shown in equation 6:

(6) $$C_t = g(R,K,Z)$$

The present value (PV) of the anticipated revenue stream is a function of B_t, C_t, and the discount rate r (see equation 11) which may vary from firm to firm.

Once the distribution of expected present value for the lease is determined, the adjustments described above take place to determine the bonus bid. Conceptually, three separate adjustments could take place, although they probably would not occur that way in practice. (The steps are isolated here for purposes of exposition only.)

The first adjustment is to compensate for risk (assuming risk averse behavior). Even if it is known with certainty that the mean expectation is unbiased, risk averse behavior dictates that the value of the lease to the risk averse bidder is not so great as the true mean expected value. Hence, this bidder would reduce his bid, below the mean lease value, to "compensate himself" for the risk he is bearing. The risk adjusted lease value, V_1, may be expressed as a function of the parameters of the present value distribution (which is a function of the input distributions) as shown in equation 7:

$$(7) \qquad V_1 = h(PV)$$

Secondly, the bidder would not likely bid his true mean expected value of the lease because of information bias, which was discussed above. The winning bidder is usually the one with the most optimistic view of the lease. In other words, the winning bidder usually holds a more optimistic set of expectations regarding the lease than other bidders and relative to actual realizations. Hence, even if the bidder were risk neutral or risk loving, he would reduce his bid because of this information bias. The extent of the reduction may be postulated as a function of the risk adjusted value (V_1) and some measure of historical experience (H) as shown in equation 8:

$$(8) \qquad V_2 = k(V_1,H)$$

Finally, it has been shown that the expected number of competitors plays an important role in bonus bid formation (Capen, et al., 1971). The competition (game theory) adjusted value (V_3) would then be a function of the information bias and risk adjusted value (V_2) and the anticipated number of competitors (N) as shown in equation 9:

$$(9) \qquad V_3 = m(V_2,N)$$

While this factor is no doubt important, we will not deal with it in this study. The game theory aspects of bidding are beyond the current scope of this analysis.

Of course, any of these values could also be expressed as a function of other variables, but the list was restricted for purposes of exposition. By combining these expressions, the bonus bid (BB) can be expressed as a function of the above mentioned variable distributions:

$$(10) \qquad BB = n(P,K,R,Z,H,r,N)$$

For illustrative purposes it is interesting to look at hypothetical linear forms of the above relationships. The following four equations illustrate such a set of simple relationships.

$$(11) \qquad \overline{PV} = \sum_{t=1}^{T} \frac{B_t - C_t}{(1+r)^t}$$

$$(12) \qquad \overline{V}_1 = \alpha_1 + \alpha_2\,\overline{PV} + \alpha_3\,(\overline{PV}/S)$$

$$\overline{V}_2 = \alpha_4 + \alpha_5 \overline{V}_1 + \alpha_6 \overline{H} \tag{13}$$

$$V_3 = \alpha_7 + \alpha_8 \overline{V}_2 + \alpha_9 \overline{N} \tag{14}$$

where $\overline{PV}$ is the mean of the present value distribution; $\overline{V}_1$, $\overline{V}_2$, and $\overline{V}_3$ are the means of the adjusted lease value distributions; and $\overline{N}$ and $\overline{H}$ are the means of the number of competitors and historical experience distributions, respectively. It is clear from this set of relationships, a gross simplification of actual real world, that values for a number of parameters (nine in this case) would be needed to form bids in this manner. In actual company decisions, the three value adjustments are probably combined into one subjectively based judgement. Nonetheless, it is important to understand the bases of the isolated adjustments when comparing alternative leasing systems.

Commonly, one major basis for comparing alternative leasing systems is the effect of risk reduction induced by alternative systems. However, in this section we have noted that at least three major factors enter into the process of bonus bid formation: 1) the impact of reducing the risk caused by uncertainty in present value estimates of lease values, 2) the impact on bidding behavior caused by information bias of the winning bidder, and 3) the effect on the bonus bid of the anticipated number of competitors in the bidding process. In some cases, it will be very difficult to isolate these differential effects when comparing alternative systems; nonetheless, it is important to retain the distinctions in order to better understand the bonus formation process and its relationship to evaluating alternative systems.

It is clear that under the assumptions of perfect competition, perfect foresight, perfect information, no tax distortions and perfect capital markets, the present cash bonus leasing system would perform exceptionally well and there would be no need to even examine alternative systems (because the cost of the investigation and the administrative and transportation costs of implementing alternatives would be greater than the benefits). However, because of the very nature of the oil discovery process, the oil industry, and the existing institutional structure, many of these assumptions are violated. In the sections that follow, we will review the characteristics of alternative systems and examine, theoretically, the potential effects of these systems in light of the bonus formation process described above.

The Current Cash Bonus System: As implied above, the winning bidder of a tract is the one that makes the highest sealed bid.[17] Heavy emphasis is placed on the bonus bid relative to other potential systems. In other words, a larger proportion of total government revenue would be expected to come

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17 For a further discussion of the planning and administrative processes now used, see Kash and White (1973) and Kalter, *et al.*, (1974).

from bonus payments.[18] Historically, the cash bonus system has been used with a fixed royalty rate of 16.67 percent although the legal minimum is 12.5 percent. The use of a royalty payment in conjunction with the cash bonus tends to partially alleviate private sector uncertainty in future prices and to some extent in reserve size. However, only the effects of reserve size uncertainty on revenues are partially alleviated; none of the cost uncertainty is reduced. Costs are a function of reserve size (because of economies of scale) as well as other factors, and all of the risk is born by the private sector. Because of the relatively high degree of uncertainty regarding costs, the risk adjustment for a cash bonus system might be quite significant.

Determining the effect of the information bias adjustment is not straightforward. It has been argued that the rate of return on oil and natural gas leases in the Gulf of Mexico is relatively low and that the low rate can be at least partially explained by a failure to understand the importance of information bias (Capen, et al., pp. 641-642). In other words, bonus bids have been "too high" given the private sector target rate of return and expected lease values. Since the bonus payment is relatively large for the current cash bonus system, such "bidding errors" could indeed result in significantly higher government revenue and a lower industry rate of return in offshore areas. However, once historical experience is gained in an area and for a particular system, this "error" should be self correcting through the learning process. In any case, the magnitude of the information bias adjustment for the cash bonus system could be relatively large because the bonus payment itself is a relatively large component of total economic rent (and government revenue).

Higher Fixed Royalty: One system which has received some attention in the past (Kalter, et al., 1974) is the possibility of utilizing a higher fixed royalty rate (greater than the current 16.67 percent) with the existing bonus system. Analysis of this system is quite similar to the current cash bonus system described above except that with higher royalty rates a greater portion of the risk is shifted to the public sector. However, as in the current bonus system, only price uncertainty and a portion of the reserve uncertainty is affected by a royalty contingency payment.

There are two difficulties with the higher rate fixed royalty system. First, there is a problem in setting the rate high enough to alleviate a substantial portion of the uncertainty without running a high risk of the rate being too high to permit economic development of the lease. The rate must obviously be set ex ante before much is known about the lease resources. If the rate is set high anticipating substantial resources and it turns out that

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[18] From 1960 through 1974, bonus payments for federal OCS oil and gas amounted to $14.5 billion and royalties amounted to $3.0 billion, undiscounted (USDI, 1975, p. 106). Of course, production for the leases issued during these years will continue into the future and the amount of royalties will increase. However, the royalty payments would need to be discounted to place them on an equivalent basis with bonus payments. The point is that bonus payments have been relatively large and quite important.

a small quantity of resource is found on the tract, the rate could reduce anticipated revenues to the point that the tract would not be developed. This problem is due to the fact that royalty affects revenues but not costs as described above.

Second, a high fixed royalty can lead to the early termination of production because unit revenues to the producer remain constant as unit costs climb through time. Hence, a royalty rate may be satisfactory to initiate production yet still cause less than an optimal quantity of resource to be recovered. This argument assumes that there is no flexibility in the level of initial capacity which is installed. Our previous analysis has indicated that, to the extent installed capacity is variable on a given reservoir, this second argument is of limited validity (Kalter, et al., 1974). In such cases, installed capacity would be reduced, production time horizons lengthened and annual production profiles reduced.

Variable Royalty Rate System: A variable royalty rate system is one in which the rate applicable during each period is dependent upon the production or value of production during that period. A higher rate applies if production is large and a lower rate for low levels of production. For example, the levied royalty rate might range from a minimum of 12.5 percent to a maximum of sixty percent depending on the production level achieved in each period. This system has the theoretical advantage of offering greater flexibility in setting the initial rate(s) without running the risk of preventing the tract from being developed as with the fixed royalty system. It also appears to alleviate the problem of early termination of production because the royalty rate falls as production declines. However, to the extent that installed capacity and the associated annual production rate is variable, a variable royalty rate could provide an incentive for spreading out production over a longer time period in order to achieve an effective overall lower royalty payment. This hypothesis will be tested in Chapter VI.

Profit Share System with an IRS Income Base: The profit share systems described in this section also make use of the cash bonus as a bid variable. Because the profit share is taken on net income, uncertainty is reduced for both costs and revenues. There are a number of ways to define net income and hence a number of possible kinds of profit share systems. The amount of reduction in uncertainty depends on the definition of the income base.

One definition of net income called the IRS base is gross revenue minus operating costs and depreciation. In essence, this definition is net operating revenue in each year with an allowance for depreciation of capital investment. Using this definition, uncertainty in initial investment cost is shared only to the extent that investment capital is recovered through depreciation during the production period. This definition of net income allows no return on capital before the profit share is taken. This and all other profit share systems considered in this section make no allowance for loss sharing in the event that no development takes place. Hence, although a substantial portion of the uncertainty in future prices, reserve size, and costs is alleviated given that development occurs, none of the uncertainty associated with the possibility of no commercial find is alleviated. However, if the size of the bonus payment is significantly reduced by any of these systems, the cost of the remaining uncertainty should be relatively low.

As with the higher fixed royalty rate system, there is a problem with the IRS profit share system in setting the rate ex ante. A rate high enough to share a substantial portion of the risk may turn out to be too high to permit profitable development on some leases. However, early termination of production, which may exist with high rate fixed royalty systems, is not a problem for profit share systems because costs are deducted before the profit share is taken.

Annuity Capital Recovery Profit Share System: One system which allows for greater risk sharing in initial investment cost is an annuity capital recovery profit share system such as the one described in the "Outer Continental Shelf Management Act of 1975" (S.521). In this system, all of the capital investment plus interest to the time production begins is converted to an annuity with a pre-specified interest rate and length of capital recovery period. The amount of this annuity (plus any annuity carried forward from previous periods) is subtracted from net operating profits in each production year to obtain the profit share base. Once the investment capital is fully recovered, the government profit share is taken from the net operating profit. Since this profit share base approximates a true economic profit share including a return to capital, the profit share rate can generally be set quite high. Hence, the problem of no development occurring with a profit share rate set too high, which occurs with the high fixed royalty and IRS profit share systems, is substantially corrected with the annuity capital recovery profit share system. However, the dry lease uncertainty still exists in this as in the other profit share systems.

British Type Profit Share System: Another system which approximates a true economic profit share plan including a return to capital is the British plan. In this system, no profit share is taken by the government until some factor times the total capital investment is recovered from net profits. For example, if total capital investment is $100 million and the recovery factor is 1.75, $175 million of net profits would be allowed before the government profit share took effect. The return to capital is implicit in the capital recovery factor which is multiplied by the initial investment cost. The economics of this system are essentially the same as the annuity capital recovery system described above, with the exception that the investment capital is recovered earlier and over a shorter (variable) time period.

Indonesian Production Sharing System: In the Indonesian system, all capital equipment (except leased or rented equipment) becomes the property of the government, but a rental rate of up to ten percent per year is allowed to be added to operating cost. In each year operating costs may be counted against the first forty percent of production, and if operating costs exceed this amount, they may be carried forward. The profit share is taken from the remaining sixty percent of production. In other words, if the profit share rate is seventy percent and production costs actually equal forty percent of production, forty-two percent of total production would be turned over to the government. This system should more properly be called a constrained profit or a variable royalty system because total recoverable costs cannot exceed the value of forty percent of production. In the above example, if costs amounted to fifty percent of the value of production, the net profit for the producer would be eight percent of the value of production (as opposed to eighteen percent when costs equal forty percent of production). If costs amounted to thirty percent of the value of production, the net profit take for the producer would be twenty-one percent of the value of production with forty-nine percent going to the government. In cases where the production rate is very high (and consequently unit costs low), the government increases its share of the after capital recovery oil.

The Indonesian system would alleviate cost uncertainty to the extent that total cost can be recovered from forty percent of the value of production. As with the IRS profit share system, no provision for a return on the initial investment capital is included in the profit share basis. The return to capital in this system is derived from the private sector's share of the remaining profit oil.

Variable Profit Share: The variable profit share system works much as the variable royalty rate systems except that the variation in profit share rate is normally expressed as a function of annual net profits rather than annual production or its gross value. The variable rate approach could be used with any of the profit share approaches described above. The advantage of a variable rate is that there is more flexibility in setting the rate *ex ante* (before reserves and costs are known) than with the fixed rate systems. Of course, to the extent that annual production rates and consequently profit rates are variable *on a given reserve base*, there may be a tendency to stretch out production in order to achieve a lower overall profit sharing rate. This possibility will also be evaluated in Chapter VI.

Working Interest Systems: Another interesting bidding variant which is included in the "Outer Continental Shelf Management Act of 1975" (S.521) is the working interest system. This system is included with both profit share and royalty options. Instead of bidding for a total tract, interested parties are allowed to bid for working interest shares. Winning bidders include that combination of bidders which sum to the highest total bid for all the working interest in the area. In this program, it is envisaged that leasing would be by large structural or stratigraphic traps rather than by 5,760 acre blocks. After the lease sale, the government would select an operator who would be responsible for exploration and development of the area in coordination with the other bid winners.

Another variation in this system is that the government would rebate one half the exploration expenses from the pool of government revenue received as bonus payments. One effect of this provision could be that increased exploration activity would be likely to take place. Exploration activity generally continues so long as the expected value of continued exploration is greater than the expected value of terminating the exploration activity. Under current tax law, the bonus payment plus all expenses on a lease can be written off as tax losses if the lease is turned back to the government. Therefore, the expected value of the lease with another exploratory well being drilled must be greater than the tax loss, or potential tax loss, for each incremental exploratory well drilled. Furthermore, as additional exploratory wells are drilled the expected value of each incremental well reduces as the probability of a major find diminishes. Hence, as additional exploratory wells are drilled, the value of the tax loss rises and the expected value of the potential reserve find falls. The point at which these two values become equal is the point beyond which no further exploration is optimal. However, if an exploration cost rebate of fifty percent is allowed, the cost of exploration curve is shifted downward and increased exploration activity may be warranted. Given the current tax laws, the major effect of an exploration cost rebate may be to increase exploration activity over what it might be in the current system.

Other than this impact, no other significant effect is anticipated. Total government revenue would be largely unaffected because the exploration cost rebate would be figured in the company's calculations in determining their bonus bids and, thus, would be included in the government revenue in one form or another. If exploration activity currently is sub-optimal, this provision would have a desirable effect. To date, no analysis has been done which examines the implications of the current tax law for the optimality of exploration activity. To accomplish this task, the discovery process would have to be modeled and combined with an economic model which optimizes over time through all the economic variables.

Other than this difference, the economics of a working interest system are basically the same as the economics of a profit share or royalty system. The cash bonus remains as the bid variable and the contingency rates function essentially the same as in the system previously described. The provision for working interest merely means that more than one owner is allowed and a number of winning bidders (instead of one) would be anticipated. Each bidder would still have to evaluate the total prospects and express his bid as a fraction of the estimated value for the total prospect.

However, there could be substantial differences in the bid determining process used by companies in bid formation. Because companies would be allowed to bid a separate amount for each working interest fraction they would be able to spread their bids to better reflect their _ex ante distribution_ of prospect value. This behavior, in turn, would have an effect on government revenue from the prospect. The bidding strategy and game theory implications for the working interest system may be quite significant, but an analysis is beyond the scope of this study.

Work Program: Another system outlined in S.521 is called a work program. Under this system the government selects a company to explore and develop a region based on a work plan submitted by that company. Profit share and/or royalty rates, as well as other fees, are negotiated between the government and the selected company. This system will not be analyzed in this paper nor explored in further detail. Little _ex ante_ economic analysis can be done when this type of system is employed. Although the system is used in several other countries, it is not likely that it will be used on a large scale in the United States since it requires administrative selection of a tract developer rather than allocation through competitive bidding.

Royalty and Profit Share Bidding Systems: All the above systems used the cash bonus as the bid variable with either fixed contingency rates or a pre-specified schedule for variable contingency rates. Alternatively, the cash bonus payment may be fixed with the royalty or profit share rate becoming the bid variable. Royalty and profit share bidding systems are not analyzed in this study, but are briefly outlined below.

Royalty Bidding System: In a royalty bidding system, the bidding variable becomes the royalty rate which is paid to the government. The analysis of uncertainty transference is essentially the same as that outlined above for royalty systems. Uncertainty in future prices and to a partial extent uncertainty in reserve estimates is alleviated. However, as explained above, all the uncertainty in future profitability is not accomodated by any type of royalty system. In addition, a royalty bidding system may have the tendency to encourage speculators to overbid in the hope that a larger than expected amount of reserves could be found, or substantially higher prices would materialize. This speculation could be encouraged because in royalty bidding with a low fixed bonus very little front end load is required. Speculation on a large discovery is possible at low cost to the private bidder.

Profit Share Bidding: In principle, a profit share bid system has the same drawback as the royalty bid system in that it tends to encourage speculation. However, because a profit share system inherently shares risk on both the cost and revenue side, the tendency toward speculation in such a system may be different than for royalty bid systems. The extent to which this is the case would depend upon the profit share base being used. Although profit share bidding has some attractive features, an in depth analysis of the system is beyond the scope of this study.

Combinations: Obviously, many combinations of the above systems could be utilized in designing a leasing approach for a given reservoir or tract proposed for sale. For example, the fixed royalty rate could be used in combination with the fixed profit share rate or in combination with the profit share bidding system. A working interest system could be designed with royalty and profit share components. Also, a royalty or profit share bidding system could be designed with a high initial cash bonus requirement or a high rental payment. Although the number of possible combinations is large, they all evolve from the same basic economic principles. No attempt will be made to outline all the possible combinations, because inferences can be drawn on the combinations by evaluating the basic alternatives described in this chapter.

Summary: In this chapter, we have discussed the implications for and outlined the principles involved in a number of alternative leasing policies and systems. We began by reviewing the goals of the public leasing program and specifying the context in which achievement of these goals would be evaluated. Assuming risk averse behavior on the part of the private sector bidders, we then outlined some important aspects of the bonus bid formation process.

This discussion of the bid formation process provided background for the description and brief theoretical structure of alternative leasing systems employing the cash bonus as bid variable. In this category, features of the current cash bonus system, a higher fixed royalty rate, variable royalty rate, IRS base profit share, annuity capital recovery profit share, British type profit share, variable rate profit share, and working interest systems were outlined and theoretical implications for risk sharing were introduced. Contingency rate bidding systems were then briefly discussed although they are not analyzed in this study.

It was seen that on a theoretical basis, very little risk is shared in the current cash bonus system, a fraction of the risk shared with a higher fixed or variable royalty rate system, and a substantial portion of the development risk is shared with capital recovery profit share systems. Because of a myriad of factors not yet evaluated, no definitive conclusions on optimal leasing systems could be drawn based on purely theoretical evidence. However, it does appear that, assuming risk averse behavior, one or more of the contingency systems would be preferable to the current cash bonus system. This hypothesis will be tested and the alternative systems analyzed empirically in Chapter VI.

Chapter IV

A Generalized Resource Leasing Policy Evaluation Model

Regardless of the energy resource being considered, private sector response to public energy leasing policies will normally follow a similar logic. Assuming competitive lease sales and a profit maximization objective function for the private sector, discounted cash flow techniques (appropriately constrained for public rules and market rigidities) can be used to simulate these responses. This chapter provides the detailed specification and description of a model, incorporating these techniques, which can be used to evaluate a number of policy questions pertaining to various energy resources located on the public domain. This generalized leasing model incorporates a number of factors important for public policy decisions into a framework of private market behavior. Economic, geological and engineering considerations relevant to private producer decision making are included so that the model may be useful for quantitatively testing the effects of a wide range of public policy alternatives. For example, the model is designed to determine the impacts of a number of alternative federal policies aimed at reducing risk for private sector resource development. A wide range of leasing policy alternatives are also incorporated into the model so that it may be used to analyze the effects of alternative leasing strategies.

This chapter is designed to provide readers with an in depth understanding of how the model works. It is not written with reference to oil and natural gas alone; rather, a generalized model description is retained which can be applicable to any energy resource. Both the theoretical and mechanical aspects are covered in great detail, in order that the reader will understand not only the theoretical rationale behind the relationships modeled but also will comprehend the means used to translate the theoretical structure into actual equations and solution procedures.

Basic Concepts: The model is designed to simulate the actions of the winning bidder in competitive leasing situations. In general, it utilizes exogenously supplied estimates of energy reserves on an individual or group of leaseholds, along with estimates of the associated production costs (investment and operating) and market prices to determine the actions of a potential leasehold developer which would maximize his after tax net present value. In so doing, the model determines the production capacity to be installed on the leasehold and the length of time that capacity is used for production. Uncertainty with respect to the key variables supplied exogenously (reserves, production costs and market prices) is incorporated via use of Monte Carlo simulation techniques which are described subsequently. Net present value calculations are carried out using discounted cash flow techniques with exogenously supplied rates of return as discount rates.

Given this basic model logic, several approaches to model solution can be used. The solution algorithm can be designed to handle installed capacity (q_o) as either a continuous value (one which can take on any value in arriving at an overall optimum solution) or as a lumpy value (one in which only prespecified capacities are permitted in model solution due to the type of production equipment which must be installed). This distinction, in large part, leads to the different model algorithms. In the former situation, equations are specified which solve for and optimize installed capacity simultaneously with other model outputs. In the latter, the discrete installed capacities which are allowable are exogenously entered into the model and the optimal capacity is determined. One advantage of this approach is that it permits economies of scale with respect to installed capacity to be considered in model solutions since unique cost relationships can be entered with each capacity examined.[19]

Figures 9 and 10 are flow diagrams for the two alternative solution algorithms. Both approaches have been programmed for model execution. The model description will follow these two flow diagrams and will separately describe the solution algorithm with continuous q_o and with exogenous q_o input. It may be helpful for the reader to refer back and forth between these two flow diagrams and the text. To make the description easier to follow, a list of all model input variables with the associated computer code, the symbol used in this description, and a brief definition is provided in Table 10. All symbols in the text and future references to variable names will refer to the variable definitions in Table 10.

After the variables are read in and stored if necessary, the first step in the model solution is to run completely through the model once using mean values for all input variables. This step determines the after tax net present value (ATNPV) if all mean values are used and converts that value into a bonus bid payment to be used in subsequent calculations.[20] This conversion is assumed to be linear according to equation 15:

$$\text{BONUS} = B_o + B_1 \cdot \text{ATNPV} \qquad (15)$$

where B_o and B_1 are the input values BCON and BFAC, respectively.[21]

The Exploration Phase of Resource Development: The next step in the model solution is to determine the exploration cost for the lease tract or area in question. For example, gross oil exploration costs (EC) are a function of the number of wells to be drilled per acre, the number of acres in the tract,

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[19] However, economies of scale with respect to reserve size can be used under both approaches.

[20] The amount of the bonus bid is necessary for use in the tax calculations. The use of mean input values to calculate the bonus serves to approximate the actual value. This can then be used in subsequent calculations where uncertainty is considered. Optionally, the bonus may also be recalculated after any number of Monte Carlo iterations for use in subsequent iterations.

[21] If B_o and B_1 are set equal to 0 and 1, respectively, the bonus will equal ATNPV. The values of B_o and B_1 depend on the bidder's risk preference function.

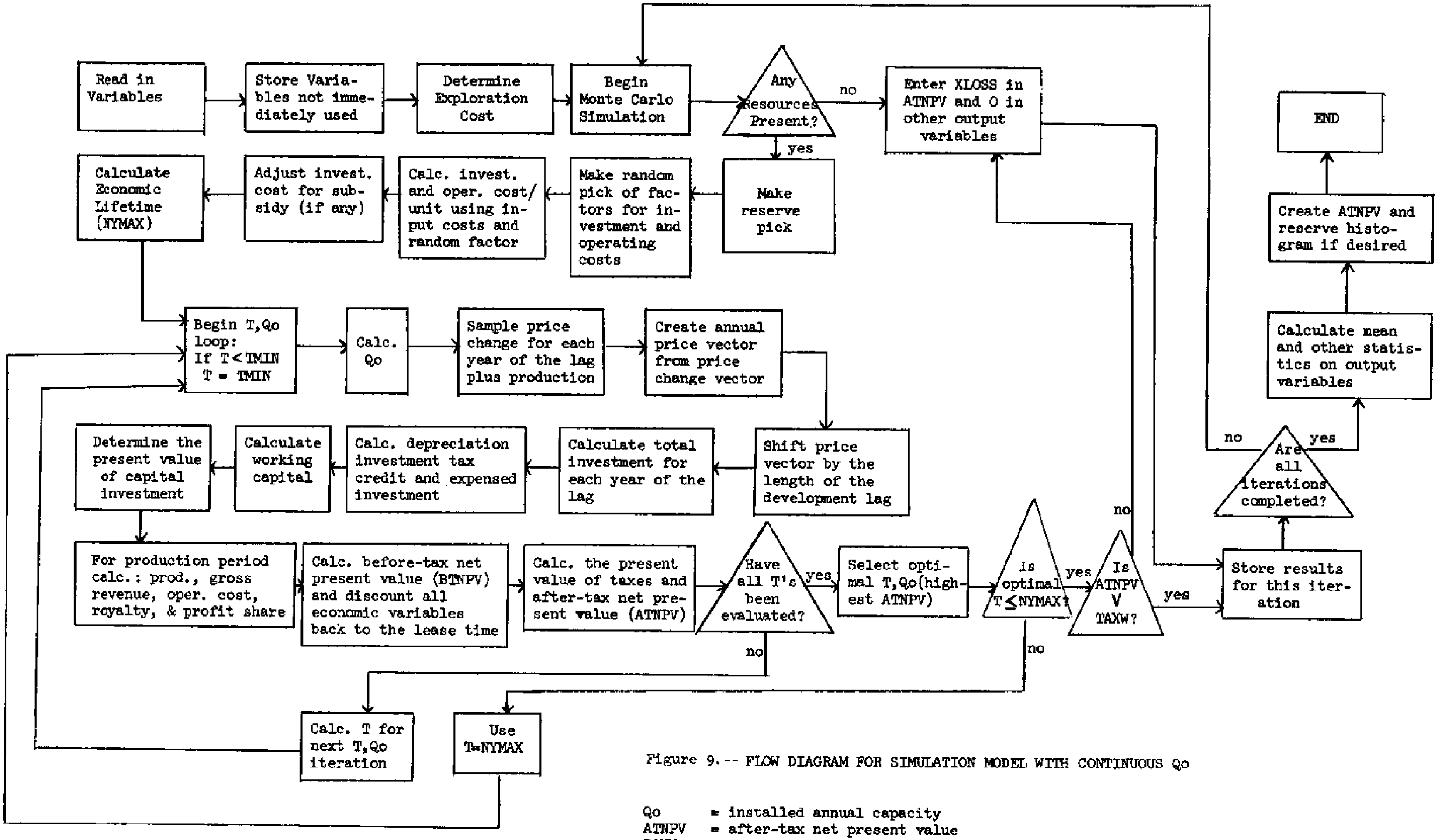

Figure 9.-- FLOW DIAGRAM FOR SIMULATION MODEL WITH CONTINUOUS Qo

Qo	= installed annual capacity
ATNPV	= after-tax net present value
TAXW	= tax write-off available if lease is not developed after exploration
XLOSS	= loss incurred from exploration of lease is not developed (exclusive of bonus)
TMIN	= minimum production time period

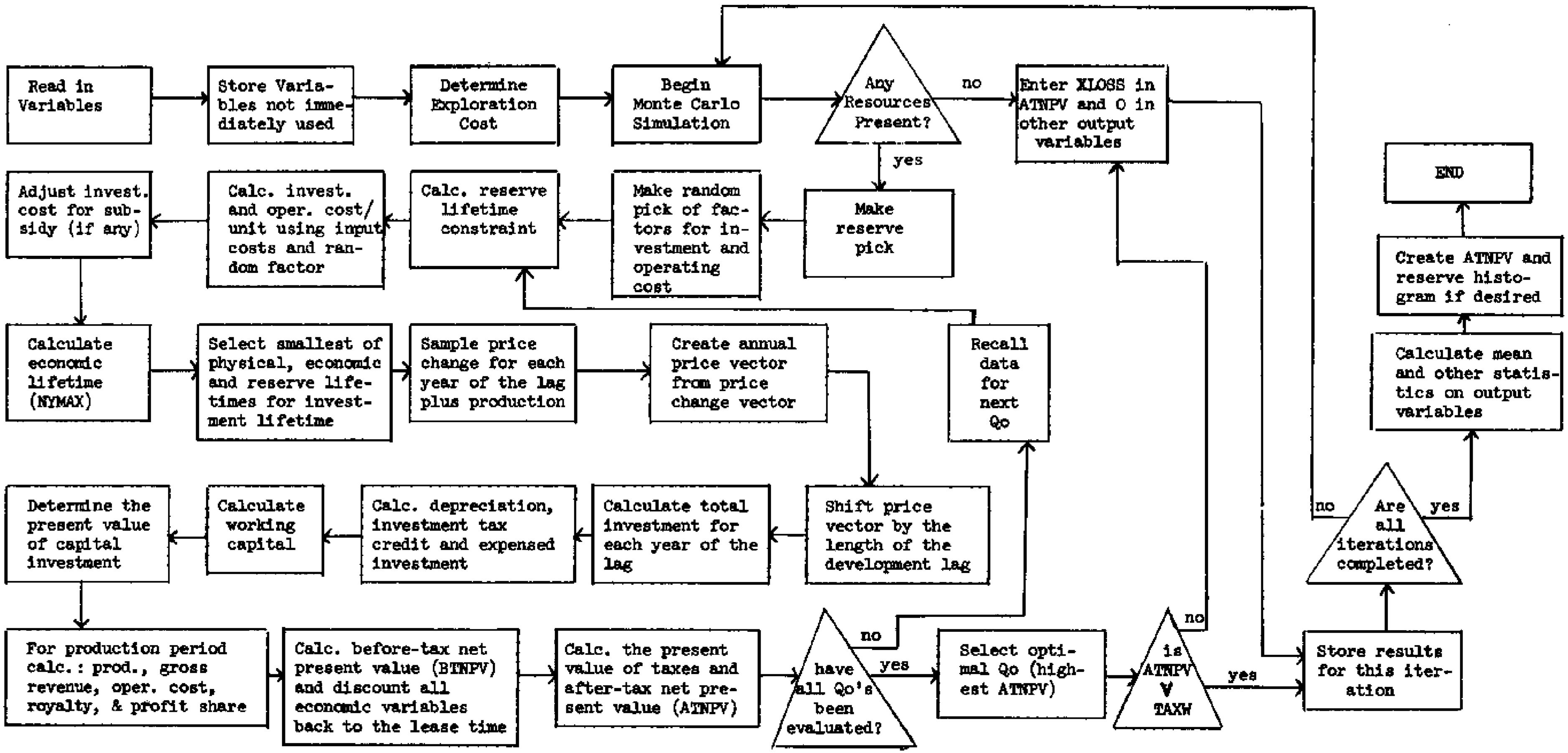

Figure 10.--FLOW DIAGRAM FOR SIMULATION MODEL WITH INPUT Qo

Qo = installed annual capacity
ATNPV = after-tax net present value
TAXW = tax write-off available if lease is not developed after exploration
XLOSS = loss incurred from exploration if lease is not developed (exclusive of bonus)

Table 10.--Some Input Variables for the Generalized Leasing Model

Symbol	Computer Code	Definition
P_o	RPO	Initial Price for the Resource
λ	RLAMB	Royalty Rate (%)
N	RN	Depreciation Period (years)
α	RALPHA	Investment Salvageable (%)
Ω	OMEGA	Investment Tax Credit Rate (%)
r	RR	Discount Rate (%)
a	X(I)	Production Decline Rate (%)
R	RCAP	Reserves (if Monte Carlo not used)
θ	RTHETA	Annual Change in Operating Cost (%)
z	RZ	Depletion Rate (%)
ϕ	RPHI	Tax Rate (%)
i	RI	Interest Rate for Capital Recovery (%)
T_p	LT	Maximum Physical Lifetime for Investment (Years)
β	RBETA	Geologic Parameter (Oil)
P_1	RP1MN	Mean of Normal Distribution of Annual Change in Price
B_1	BFAC	Factor Used to Adjust ATNPV to Determine Bonus
B_o	BCØN	Constant Used to Adjust ATNPV to Determine Bonus
s	ST	Rate for State Severance Tax (on Gross Value)
B	IBP	Length of Production Build-up Period
AGFAC	AGFAC	Factor for Determing the Amount of Associated Gas (or any second resource)
GP_o	GPØ	Initial Price for Gas (or any second resource)
R	RMEAN	Mean of Reserve Distribution
F	IFLATP	Length of Time the Initial Production Level is Used
Q_o	QO	Installed Capacity (Annual)
b	RBQ	Cost per Unit of Installed Capacity
K_o	RKO	Operating Cost per Unit
L	LAG	Investment Lag -- Construction Period (Years)
f	F	Proportion of Investment Expended in Each Lag Year (vector of L dimension)
y	YZ	Proportion of Yearly Investment which is tangible (Oil)
RENT	RENT	Annual Rent per Acre
h_i	BPP	Factor Applied to Capacity to Determine Production During IBP

and the cost per well.

(16) EC = Wells/acres x acres x dollars/well

This amount is adjusted by deducting tax savings from expensed investment and other tax deductions, and adding rental payments during the exploratory period.

In addition to calculating the net expenses of exploration, the potential tax write-off available to the company if the lease is not developed is also calculated. This potential tax write-off is the bonus payment plus the book value of depreciable exploration expenses multiplied by the tax rate. The value is used later in the program to compare with the potential present value of the lease if developed to decide whether or not it is advantageous to develop the lease.

For resources such as coal or oil shale, the same principles are involved in determining exploration expenses and potential tax write-offs, but the functional relationships used in determining exploration costs would differ.

Uncertainty and the Monte Carlo Analysis: For policy analysis, it is important to determine the potential effects on private decisions of uncertainty with respect to future prices, production costs, and reserves. Using the mean (average) values of probability distributions is inadequate for this analysis because only outputs resulting from these mean values are produced. No measure of the spread (variance) of potential outcomes is obtained. In other words, in the absence of some type of simulation, no measure of the potential riskiness of the final outcome is derived (and of course, the probability of the expected mean actually occurring is zero). For policy purposes, it is desirable to learn not only how the mean output values are affected by various policy options but also how the variance or range of the outcomes is changed.

For example, suppose two policy options have identical effects on the means of relevant policy objectives (model outputs), have identical costs (in whatever terms cost is measured), but have differential effects on the expected outcome variances. Naturally, the policy maker would want to incorporate the variance in his policy decision. In every case the variance or range of possible outcomes is a piece of information which is valuable to the decision maker attempting to influence private market behavior.

Monte Carlo simulation is one technique for handling the problem of uncertainty in input values and to estimate the variance in potential outcomes. Rather than using point estimates of uncertain input variables, an assumed probability distribution is provided from which samples are taken to be used as inputs for the analysis. The process of sampling each variable from its unique probability distribution and performing the model calculation is repeated many times to produce a range of model output values. A frequency distribution of these output values can be derived and the mean and variance of the expected outcomes determined. In performing this type of simulation we replace the unknown actual population of future prices, costs and reserves by an assumed probability distribution from which samples are drawn. By sampling many times it is possible to generate many possible combinations of prices, costs and reserves that together produce outcomes, each in the appropriate proportion (King, p. 303).

Any type of probability distribution may theoretically be specified for the uncertain variables. Figures 11, 12, 13 and 14 depict the normal, triangular, uniform and lognormal distributions, respectively. The uncertain variables used in this model and the type of distribution which is used for each variable are listed below.

Variable	Distribution
Annual price change	Normal
Investment cost contingency factor	Triangular
Operating cost contingency factor	Triangular
Presence or absence of resources (Bernouli)	Uniform
Amount of reserves	Lognormal or normal

The rationale behind the selection of these distributions is provided in the discussion of the uncertain variables which follows.

Future Resource Prices: Uncertainty in future resource prices is handled by randomly selecting the annual change in price each year from a normal distribution with a specified mean and variance. This vector of sample annual price changes together with the initial resource price, P_o, is used to create a vector of initial prices for each year of potential lease duration. Equation 17 illustrates this process.

$$(17) \qquad P_o(t+1) = P_o(t) \cdot e^{P_1(t)}$$

$P_o(t)$ is the initial resource price in year t, $P_1(t)$ is the rate of change in price during year t (from the vector of price change samples), and $P_o(t+1)$ is the initial resource price in year (t+1). This vector of initial prices for each year and the vector of price changes during each year are used in the model computations to determine gross revenue for each year of production. Since this procedure is repeated independently for each Monte Carlo iteration, a separate price distribution emerges for each year of the production period. Because the annual price change has a compound effect upon the initial price, the mean and variance of these annual price distributions could also change through time.[22]

The price change used is assumed to be the expected price change in excess of general inflation. It is not the total expected change in price of the resource; rather, it is the difference between the expected change in price

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The resulting annual price distributions can be truncated and possibly skewed. For example, if policy options involving price support levels are simulated or minimum prices are used, the support levels may be high enough to affect prices, truncate the lower end of the price distribution and, implicitly, the price change distribution.

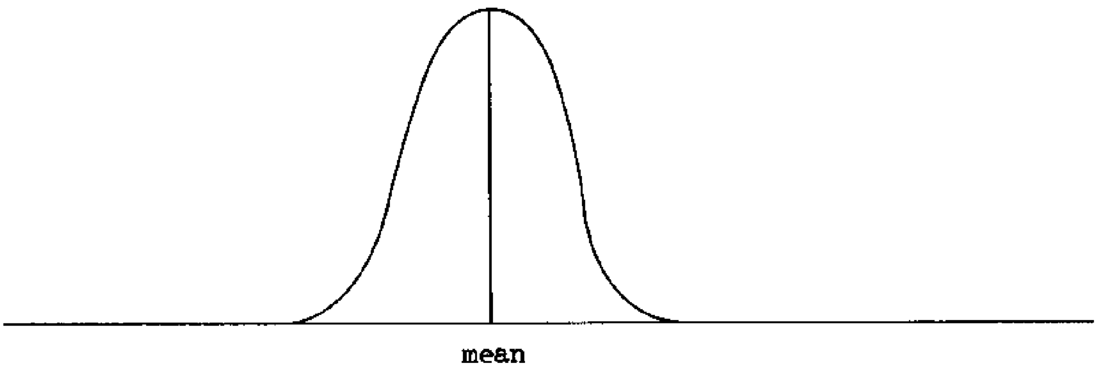

Figure 11.--Normal Distribution Used for Annual Price Change and Reserves

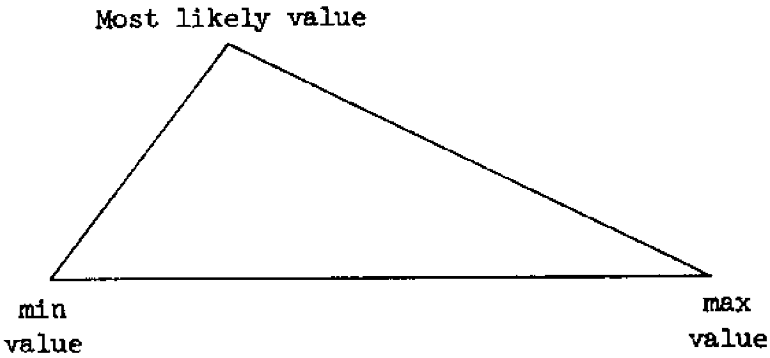

Figure 12.--Triangular Distribution

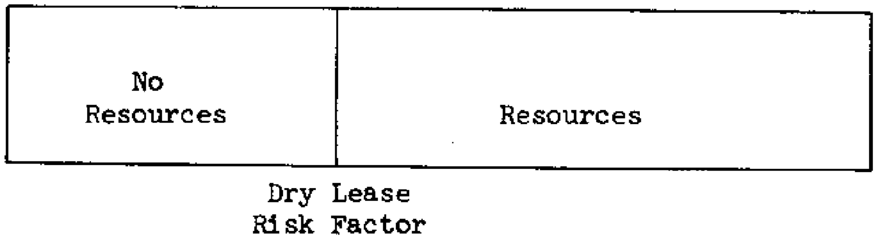

Figure 13.--Uniform Distribution

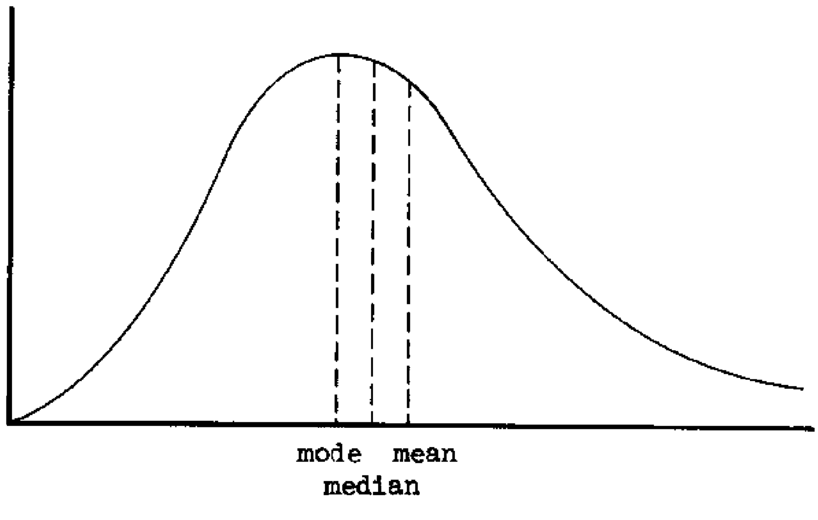

Figure 14.--Lognormal Distribution

of the resource and the expected general rate of inflation. This same principle applies to investment and operating cost factors. Thus, the relative inflation rate between revenues expected from the resource and cost to obtain the resource is a derivative of the inputs to the model. Because both cost and revenue inflation factors are keyed to general inflation, relative inflation between costs and revenues for a particular investment can be automatically accounted for using this procedure.

Investment Cost Contingency Factor: Investment costs are uncertain for at least three reasons, and a cost contingency factor is used to incorporate this uncertainty into the model. The contingency factor is a percentage of the estimated investment cost and is selected from a triangular distribution with an input minimum, maximum and most likely value.

One of the most important reasons for a contingency factor in investment cost is that inflation in construction costs in recent years has taken place at a rate higher than the rate of general inflation. Although this experience will not necessarily continue, it is uncertain what the rate will be over the next decade. Since the construction and start-up period for an energy extraction facility may be five years or more, the rate of inflation can have a significant effect on total construction costs. Second, investment costs may be uncertain because technology for extracting and refining some resources is relatively new. For example, sub-sea completions required in some offshore areas represent a new technology. Unforeseen engineering and technical problems could raise such investment costs substantially. A third reason for an investment cost contingency factor is that the length of the development and construction period required for facilities of the type and scale required may not be known with certainty. Changes in the assumed period will have a significant impact on the present value of investment costs.

As is evident from the discussion of these factors, the distribution of investment cost uncertainty tends to be one-sided. In other words, the risk is mainly on the high side, so the contingency factor distribution would be expected to be skewed in that direction.

Operating Cost Contingency Factor: The two factors affecting annual operating costs in the model are θ, the annual increase in cost per unit, and K_o, the initial operating cost per unit. For purposes of analysis, θ is assumed to be known and constant throughout the production period, and a triangular distribution of K_o values is utilized. Uncertainty in initial operating cost arises from the same sources as for investment cost (future relative inflation and unforeseen technological difficulties) plus uncertainty in the future cost of environmental protection. Since future government regulations are unknown or are subject to modification, it is difficult to forecast the environmental control costs which must be borne by the private sector. However, once production has begun with technological problems solved and environmental control equipment in place, future changes in operating cost should be subject to less uncertainty. Therefore, the initial operating cost, K_o, was assumed to be uncertain with risk mainly on the high side.

In addition to the factors K_o and θ, <u>unit</u> operating costs are also affected by the rate of decline in production. Since total operating costs are determined by the factors described above, unit operating costs rise as production falls. This point is discussed further at a later point in the text.

Presence or Absence of Resources: This variable is particularly relevant for oil and natural gas production. When some quantity of resource is known with certainty to be present, the variable may be set to zero, and the model then assumes resources are always present on the lease area. When the variable is operative, a random number generator is used to generate a random number between zero and one from a uniform distribution. This random number is then compared with the dry lease risk factor to determine if resources are present for this iteration. If the random number is greater than or equal to the dry lease risk factor, then resources are assumed to be present and the model computations continue. For example, if the random number generated were .13 and the dry lease risk factor .10, then resources would be present for this iteration. Clearly, if the dry lease risk factor is set at zero, then all random numbers between zero and one will be greater than or equal to the dry lease risk factor and resources will always be present.

Amount of Reserves: For some resources such as oil and natural gas, the greatest source of uncertainty is the amount of reserves present on a leasehold. For almost all resources some degree of uncertainty about the total quantity of resources in place exists.

Relating to petroleum exploration, a number of researchers have found that the lognormal distribution provides a good fit for experimental data on the size of petroleum deposits (Uhler and Bradley; Miller, et al.; Kaufman, 1963). Therefore, the lognormal distribution is used for the size distribution of petroleum resources and in other situations where deemed appropriate.

For resources which are not distributed lognormally, the normal distribution may be used in the simulation program. In either case, the mean and standard deviation and distribution desired are model inputs.

The Model Description with Monte Carlo Simulation: Once the Monte Carlo simulation begins, each of the procedures is repeated for each iteration of the simulation. In other words, if 200 Monte Carlo iterations are specified, all of the steps from this point on are repeated 200 times. The results of each iteration are stored and used to calculate the mean and other statistics on output variables.

The first step in the Monte Carlo simulation is to determine if there are any resources present on the lease. The chance of the lease having no resources is an input variable, DTRSK. A random number is selected from a uniform distribution and compared with this factor to determine if resources are present for each iteration, as explained above. If no resources are present, the loss incurred from exploration is entered into the after tax net present value factor (ATNPV) and used in calculating the expected present value of the lease over all iterations. The iteration is terminated and a new iteration is begun.

If resources are found on the tract, the next step in the process is to make a random selection of factors to be used in determining total investment and operating costs. A choice of three methods is allowed in making this selection of factors. First, the investment and operating cost input values may be used without any random component added. In this case, the random selection process is bypassed. Alternatively, a cost adjustment factor may be selected from the triangular cost distributions supplied for both investment and operating costs. For both, the minimum adjustment factor, the most likely adjustment factor and the maximum adjustment factor are inputs determining the shape of the triangular density function. For example, the cost factor could range from 0 to .2 with a most likely value .1. In this case an equilateral triangular density function would be employed. Either the mean of the triangular distribution or a random selection from that distribution may be used to determine the actual adjustment factor. The adjustment factor is then multiplied by the base cost with the result being added to the base cost. In essence, the random cost component which results from the adjustment factor is a contingency. The actual amount of the contingency may be zero (if the base value is used), equal to the mean of the triangular distribution, or randomly selected from the distribution. Normally, the random selection method would be used because contingency is considered a random component of total cost. Hence, the random selection method is considered to better reflect actual operating conditions.

The next two steps in the model simulation vary depending upon whether installed capacity is an input vector or determined within the model. If installed capacity is internally determined, the random factors for investment and operating costs are immediately used to determine the investment and operating cost values which will be used for each installed capacity. If installed capacity is an input, associated investment and operating cost values are also input. The same random factor is applied to each of the investment and operating cost values for each installed capacity to determine a unique set of cost values. In other words, there is a fundamental difference between the two versions of the model in that economies of scale with respect to installed capacity are permitted if installed capacity is input to the model, but are not permitted if installed capacity is solved for within the model. However, economies of scale with respect to reserve size are permitted under both approaches. Once investment and operating costs are calculated, an investment subsidy may be subtracted if one is used for purposes of policy analysis.

If installed capacity is an input vector to the model, each capacity together with reserves and other input variables is used to determine the maximum production time horizon which can be used given the installed capacity and the amount of reserves. On the other hand, if installed capacity is solved within the model, a time horizon and the corresponding (maximum) installed capacity is determined internally. Since each of these procedures represent a different solution to the same basic structural relationship, we will develop that relationship carefully and explain the correlation between the two procedures.

Economic, Engineering and Geologic Relationships: We begin with the simple depiction of the relationship between reserves and production. Reserve estimates enter the calculus of profitability both as a basis for the investment and as a constraint on the production from an investment. The production constraint is represented in equation (18):

$$xR \geq \sum_{t=1}^{T} qq(t) \tag{18}$$

where R represents the amount of the resources in place, x the recoverable fraction with a given technology, qq(t) the amount of annual production, and T, the production time horizon. This equation merely states that the sum of production through time can be no greater than the recoverable portion of the reserves in place (with a given technology). Given this constraint, the producer attempts to select an initial plant capacity which will maximize his return through time. In other words, the producer attempts to select the investment which maximizes his after tax net present value of revenue subject to the production constraint.

Assume for the moment that production declines exponentially through time.[23] Annual production may then be expressed as a function of initial installed capacity as in equation (19):

$$qq(t)_i = \int_{t-1}^{t} q(o)_i e^{-at} dt \tag{19}$$

where $q(o)_i$ represents initial installed capacity of the ith plant which is one of a group of possible initial capacities.[24] While this simple relationship between installed capacity and annual production may be adequate for oil resources after a period of time, it is not adequate for other resources or for oil resources during the early production phase. A typical resource production pattern includes a production build-up period during which production is increasing each year as installed capacity is coming on stream followed by a flat production period which continues indefinitely or is followed by a declining production period as shown in Figure 15. When a production build-up or flat production period is used, $q(o)_i = qq(t)$ during the years through F. Under this scenario, total production during the lease life is given by equation (20):

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[23] In this text the variable t is used in two ways. When discrete values or summation is implied as in equation (18), t represents a time period; i.e., one year. When t is used in an integral form, it represents a point in (continuous) time as in the right side of equation (19). Equation (19) should be interpreted as the amount of production in year t (left side) is equal to the integral of production from the beginning of the year (point t-1) to the end of the year (point t). The discrete time period values are indexed to begin with period 1, and the continuous time value begins at point 0. This somewhat unconventional notation was selected to simplify exposition of the model equations which involve both discrete and continuous summation and discounting.

[24] For some resources, the value of the production decline rate, a, may be set equal to zero. In that case annual production, $qq(t)_i$, becomes equal to initial installed capacity $q(o)_i$ throughout the production period.

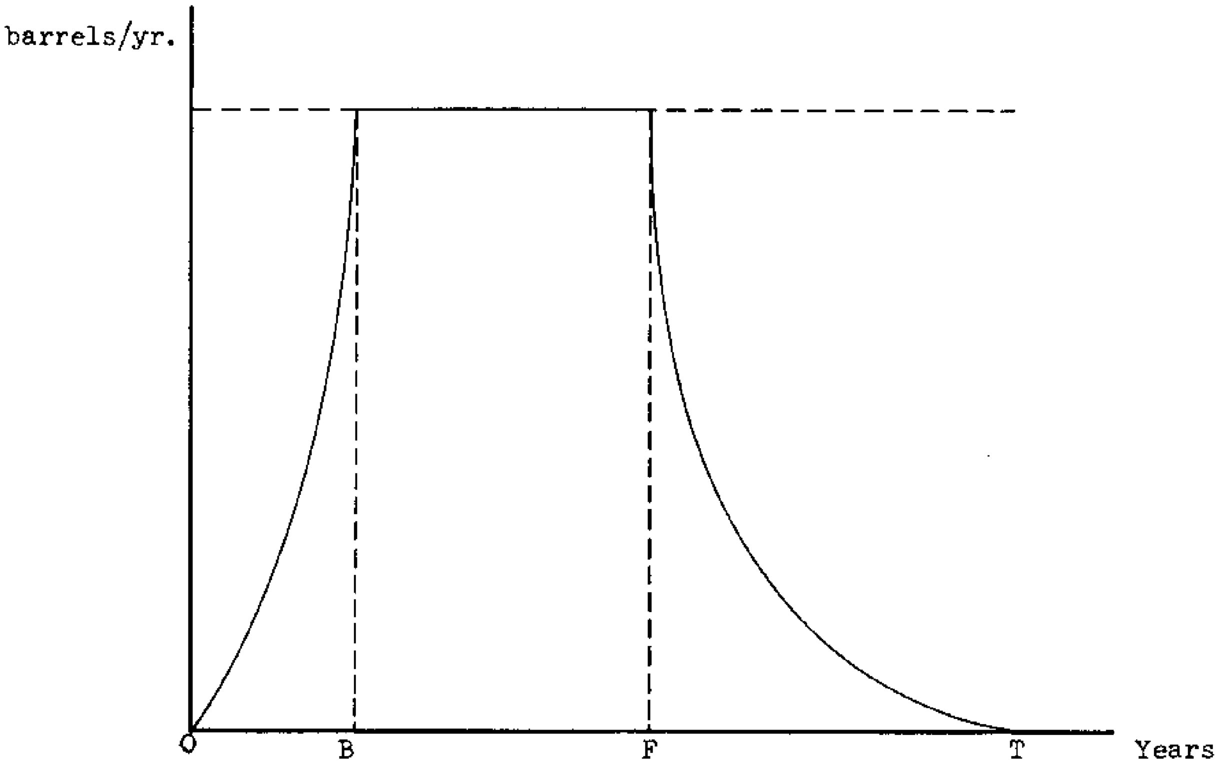

Figure 15.--Production Profile Through Time

$$\text{PROD} = q(o)_i \cdot \sum_{j=1}^{B} h_j + q(o)_i \cdot (F-B) + \int_{o}^{T-F} q(o)_i e^{-at} dt \tag{20}$$

where the build-up period is the period between year one and year B, the flat production period is between year B and year F, and the declining production period (perhaps at a zero rate) is the period from F to T; T being the production life of the lease as determined below.[25] Equation (20) gives the sum of production during each of the three phases of production. Production during the build-up period is equal to the sum over the build-up period of the annual factors h_j times installed capacity; production during the flat period is simply the number of years in which production is constant times installed capacity; and production during the decline period is equal to the integral over the number of years production is declining.

Recalling from equation (18) that total production must be less than or equal to recoverable reserves, we may now combine equations (18) and (20) to yield the relationship between recoverable resources and installed capacity:

$$xR - \beta q(o)_i e^{-a} \geq q(o)_i \cdot \sum_{j=1}^{B} h_j + q(o)_i \cdot (F-B) + \int_{o}^{T-F} q(o)_i e^{-at} dt \tag{21}$$

The β parameter is a geologic variable applicable to oil which relates total recovery to the rate of recovery. (The faster the oil is produced, the lower is total recovery.) For resources such as coal and oil shale or any resource other than petroleum, the geologic factor β may be set equal to zero. In that case, recoverable reserves, xR, is greater than or equal to production as defined in equation (20).

By assuming that recoverable reserves are exhausted, we may change equation (21) from an inequality to an equality and solve for either q_o or T.[26] Equation (22) represents the solution of equation (21) for T which is used in the case of input q_o:

$$T = \left[\ln \left[1 + a(-xR/q_o + \beta e^{-a} + \Sigma h_i + F - B)\right] \right] / -a + F \tag{22}$$

Equation (23) represents the solution to equation (21) when installed capacity, q_o, is solved within the model:

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[25] The integral for the decline period goes from zero to T-F rather than F to T because this integral properly measures the sum of production over the decline period.

[26] The notation, $q(o)_i$, is here changed to q_o representing one potential investment, but the reader should be aware that the optimization process to be used covers all available investment opportunities.

$$q_o = \frac{axR}{[1 + a(\beta e^{-a} + \Sigma h_i + F - B) - e^{-a(T-F)}]} \tag{23}$$

Equations (22) and (23) are derived by integrating equation (21) and solving algebraically.

Given that q_o and T have been determined either by input or within the model, the production time horizon, T, must be subjected to two constraints before it can be employed. These constraints are the physical and economic lifetimes of the proposed investment. The production time horizon for a given investment can be no greater than the actual physical lifetime of the initial plant.[27] Nor can the production time horizon exceed the time at which variable unit cost of producing the product exceeds the revenues per unit obtained from marketing it. In other words, when the steadily increasing unit costs of production (assuming a rising MC curve) exceed the revenues per unit of production, production would cease.

The first constraint is simply expressed as an exogenously determined constant:

$$T \leqq T_p \tag{24}$$

where T_p equals the maximum physical lifetime of the investment. The second constraint is the limit obtained when marginal cost equals marginal revenue. Equation (25) states that the economic limit occurs when operating costs plus taxes exceed or equal revenue minus royalties and severance taxes:[28]

$$\begin{aligned}(1 - \lambda - s)P_o e^{P_1(t+L)} \leqq K_o e^{[(\theta+a)t-aF]} &+ \phi[(1-\lambda-s)P_o e^{P_1(t+L)} \\ &- z(1-\lambda-s)P_o e^{P_1(t+L)} - K_o e^{[(\theta+a)t-aF]}\end{aligned} \tag{25}$$

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[27]This does not necessarily mean that the energy resource on the leasehold has been exhausted. As a result, the winning bidder may want to reinvest in order to continue production until the point where resource exhaustion takes place. Whether such investment will, in fact, occur depends upon economic considerations present at that point in time. The extent of the remaining resource will play a substantial role in this decision. The model can be modified to incorporate this later investment decision if it is assumed important (in a present value sense) for initial bidding behavior.

[28]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 through time. This phenomenon can be due to equipment obsolescence, logistical problems with production and/or increased maintenance costs and relative inflation. (Arps; Davidson; U.S. Department of the Interior Officials). In notation form, total operating costs in any time, t, are expressed as $q_o K_o e^{\theta t}$. Thus, unit costs become:

Solving equation (25) for the time constraint yields:

$$(26) \qquad T \leqq \left[\left(\ln\left[\frac{(1-\phi)K_o}{(1-\phi+\phi z)(1-\lambda-s)P_o}\right]\right) - aF - P_1 L \right] / (P_1 - \theta - a)$$

Note that this equation may be negative or undefined when the rate of change in price is greater than or equal to the decline rate plus the rate of change in unit operating cost ($P_1 \geq \theta + a$). The negative sign occurs because the marginal revenue-marginal cost curve intersection is in the negative quadrant to the left of the origin as shown in Figure 16. The correct interpretation for this negative sign is that the economic time constraint is infinite.

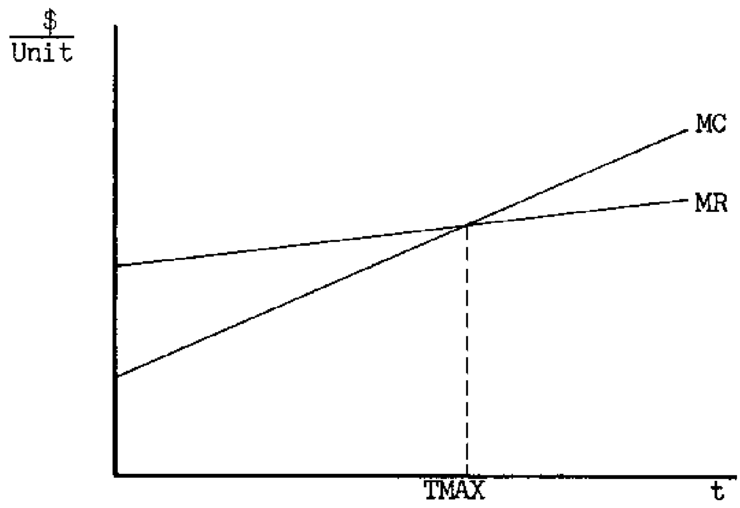
We now have each of the equations and relationships necessary to determine the production time horizon. The production time horizon is that T determined in the model either by equation (22) or through the q_o, T optimization procedure, subject to the physical and economic lifetime constraints given by equations (24) and (26). Hence, the production time horizon is the minimum of the resource exhaustion time period, the time period for the physical life of the plant, or the economic production time constraint. Mechanically, these equations differ slightly depending on whether installed capacity is input or determined by the model as explained above and as outlined in Figures 9 and 10.

For the first q_o, T set to be evaluated in each Monte Carlo iteration, the next step is to create a vector of prices covering each year in the production period. The first step in this process is to create a vector of annual price change covering at least the period from the time of the lease sale to the end of production. This vector may be created by randomly sampling from a normal distribution of price change with an input mean and standard deviation as explained above. Alternatively, the mean annual price change may be used for each year in the vector.

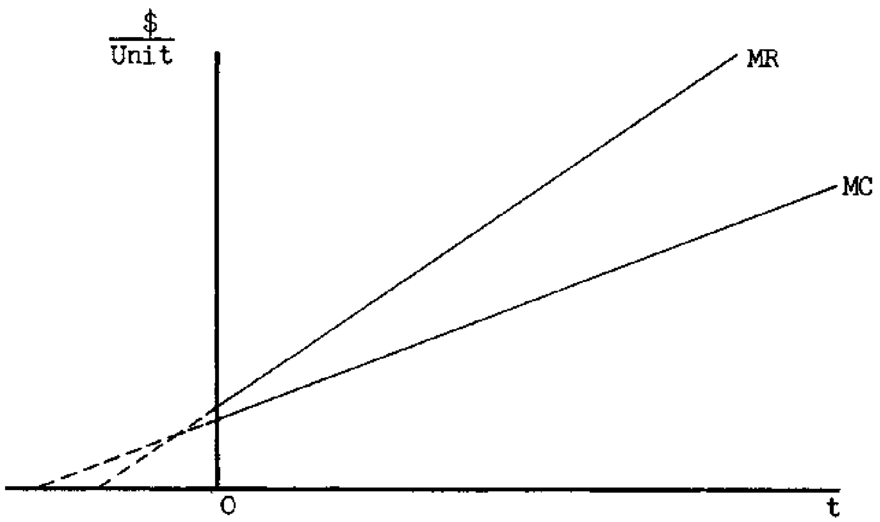
If desired, more than one price change distribution may be used in generating the price change vector. The model allows for as many as four unique price change distributions to be input for up to four specified time periods. For example, price could be expected to rise at an annual rate of eight percent for three years, fall at a rate of three percent for six years, remain relatively constant for eight years, and then rise at a rate of four percent through the end of production. Each of the expected price change values would have a unique variance, so that the variance as well as the expected value of annual price change can differ through time. The price change vector is created by utilizing the appropriate distribution for each year in the vector.

$$q_o K_o e^{\theta t} / q_o e^{-a(t-F)} = K_o e^{[(\theta+a)t-aF]}$$

The denominator of this fraction is derived from the last term of equation (21).



Finite Solution



Infinite Time Horizon

Figure 16.--Solution to the Economic Time Horizon

The next step is to create a vector of prices from the lease time until the end of production using the initial input price P_0 along with the vector of price changes. The vector is created by multiplying the price at the beginning of each year by the exponential price change during that year to get the price at the beginning of the next year (see equation 17). This process is repeated until prices have been generated for each year until the end of production.

For computational purposes, only prices during the production period are relevant; prices during the construction and development period are not needed for the analysis. The price vector must, therefore, be truncated by the length of the development period (lag) and reindexed. In other words, a new price vector which begins with the initiation of production must be created from the original price vector which begins at the point of the lease sale. Correspondingly the vector of annual change in price must also be reindexed by this same amount. Once this is accomplished, the vectors of price and price change correspond to the years of production.

The next step is to calculate the investment for each year of the construction and development lag and the discounted value of total capital investment. Total capital investment is determined by multiplying installed capacity, q_o, by the investment cost per unit of installed capacity, b, as determined in the cost estimation procedure for each resource. To determine the discounted value of total investment, the total investment figure must be multiplied by the percentage of total investment occurring in each year of the development period and the resulting investment value for each year discounted back to the beginning of the lease. Both development costs and exploration costs for each year are summed together and discounted back to the beginning of the lease. In functional form this relationship is expressed in equation (27):

$$\text{(27)} \qquad PVI = \sum_{i=1}^{L} (q_o \cdot b \cdot f_i + EX_i)/(1+r)^i$$

where PVI represents the present value of investment, f_i the factor used to determine the proportion of investment in each year of the lag, and EX_i the exploration expense during each year of the lag. The values for total annual investment are then used to calculate depreciation streams for both the lag and production periods; and to calculate expensed investment and the investment tax credit.

The model allows any of the following forms of depreciation to be used:

1. No depreciation

2. Sum of years' digits (SYD) depreciation with input depreciation lifetime (N)

3. Double declining balance (DDB) with automatic conversion to straight line (SL) at the appropriate time - using input depreciation lifetime

4. Straight line using input depreciation lifetime

5. Asset depreciation at the same rate as the resource is depleted (annual production/total production) - using the production horizon as depreciation lifetime

6. SYD with the production horizon as N

7. SL with the production horizon as N

8. DDB with the production horizon as N

According to IRS regulations, capital investment cannot be depreciated until it is placed in service. Therefore, all tangible investment during the development period is depreciated beginning with the first year of production. The annual depreciation values are used in profit share calculations and discounted back to the beginning of the lease.

Tax savings during the exploration and development periods result from expensed (intangible) investment (EXXINV and EXINV), rental payments during exploration (RENT), and the investment tax credit (IVTC) (at the beginning of production). Equation (28) gives the tax savings during exploration (EXTXSV) and equation (29) computes the total tax savings before production commences.

(28) $$\mathrm{EXTXSV} = \phi(\mathrm{RENT} + \mathrm{EXXINV})$$

(29) $$\mathrm{TAXSAV} = \phi(\mathrm{EXINV}) + \mathrm{EXTXSV} + \mathrm{IVTC}$$

Depreciation (DP), EXTXSV and TAXSAV are discounted to the beginning of the lease.

Working capital is then calculated as a function of the first year's operating cost. Once this calculation is complete, the model then enters the production loop. In this loop, annual and total production, gross revenue, operating cost, royalty, severance tax, depletion, and profit share are calculated. Because many of the equations are in integral form, yet many of the values are needed on an annual basis, integral solutions are obtained over each year of production and then summed over the production period. For example, production is obtained from point zero to the end of year one and then from the beginning of year two to the end of year two and so on through the beginning of the last year of production to the end of the last year of production. These values are then summed to determine total production. In this way both annual and total values can be obtained for variables such as production, profit share, and royalty; and continuous discounting is maintained for variables such as gross revenue and operating cost.

The methods used to determine annual production in each year of the production period are described in detail above. In addition to calculating production for the basic resource, production is also calculated for any associated resource such as associated gas with petroleum production. The ratio of production between the major resource and the secondary resource is assumed to be a constant factor. In other words, to determine the production of associated natural gas in each period, the production of oil is multiplied by the factor (AGFAC) to determine the production of natural gas. In the equations that follow the annual production of the major resource will be denoted by q_t and production of the secondary resource will be denoted g_t.

A number of equations are used in calculating the economic variables for each year of the production period. So that this process may be clearly understood, the equation for gross revenue is presented below in two forms:

1. The integral form divided into annual periods.

2. The computational form used in the model.

For simplicity of exposition, the values of F and B are assumed equal to zero. Hence, equations (30) and (31) represent the two forms of the gross revenue equation during the period of production decline:[29]

$$(30) \qquad GR = \sum_{t=1}^{T} \left[q_t P_t \int_o^1 e^{P_1 t} dt + g_t GP_t \int_o^1 e^{GP_1 t} dt \right] \int_{t-1}^{t} e^{-rt} dt$$

$$(31) \qquad GR = \sum_{t=1}^{T} \left[q_t P_t \left(\frac{e^{P_1} - 1}{P_1} \right) + g_t GP_t \left(\frac{e^{GP_1} - 1}{GP_1} \right) \right] \left[\frac{e^{-rt} - e^{-r(t-1)}}{-r} \right]$$

Note that the annual values calculated in equation (31) are discounted to the beginning of the production period. Calculation of annual operating cost (OC) proceeds in the same manner as shown in equations (32) and (33):

$$(32) \qquad OC = \sum_{t=1}^{T} \left[q_o K_o \int_{t-1}^{t} e^{\theta t} dt \right] \left[\int_{t-1}^{t} e^{-rt} dt \right]$$

$$(33) \qquad OC = \sum_{t=1}^{T} q_o K_o \left[\frac{e^{\theta t} - e^{\theta(t-1)}}{\theta} \right] \left[\frac{e^{-rt} - e^{-r(t-1)}}{-r} \right]$$

As is clear from equations (32) and (33), operating cost throughout the life of an investment is assumed to be dependent upon the initial installed capacity. The marginal cost of extracting the secondary resource is assumed to be zero, <u>or</u> included in the cost of extracting the primary resource.

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[29]Actually P_1 and GP_1 are also time indexed variables as explained above, but they are written here in unindexed form for clarity of exposition. P_t and GP_t represent prices at the beginning of year t, and q_t and g_t represent production during year t.

According to IRS regulations, the bonus payment may be depleted (depreciated) in proportion to the depletion of reserves held. Accordingly, the proportion of total production produced in each year is multiplied by the original bonus and discounted to calculate the present value of bonus depletion. The annual values of gross revenue and cost, depreciation (DP_t), rent, and bonus depletion (BDP_t) are used to calculate the annual profit share base (PSB) as shown in equation (34):

$$(34) \qquad PSB = (1-\lambda-s)[P_t \cdot q_t + GP_t \cdot g_t - OC_t - DP_t - RENT - BDP_t]$$

To determine before tax net present value (BTNPV), the difference between gross revenue and operating cost is discounted to the beginning of the lease and the discounted values of royalty, capital investment, profit share, and severance tax are subtracted. For resources for which depletion is still allowed, depletion is calculated as the present value of gross revenue minus the present value of bonus depletion (BDF) multiplied by one minus the royalty rate (λ); that quantity multiplied by the depletion rate (z) as illustrated in equation (35):[30]

$$(35) \qquad DPL = z \cdot (1-\lambda)(GR-BDP)/(1+r)^L$$

Taxable income is the present value of investment plus before tax net present value minus the present value of depreciation during production minus the present value of bonus depletion as shown in equation (36):

$$(36) \qquad TXINC = BTNPV + PVI - DP - BDP - DPL$$

The present value of taxes paid is simply the taxable income multiplied by the tax rate minus the tax savings during the development period. A check is included in the model to eliminate the possiblilty of negative taxes. The implication of this constraint is that companies are not allowed to calculate investment profitability for any particular investment based on excess tax write-offs to be obtained from that investment. Excess tax write-offs are allowed in the simulation program when development does not occur, but excess write-offs are not allowed ex ante as a basis for calculating investment profitability when development does occur.

After tax net present value (ATNPV) is simply the difference between before tax net present value and present value of taxes paid plus the present value of the original investment at the end of production as shown in equation (37):

$$(37) \qquad ATNPV = BTNPV - TAX + (SALVG + w)/(1+r)^T$$

where SALVG represents salvage and w, working capital. The after tax net present value calculated as described above represents the net worth of the

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[30] A check is provided in the program to make sure that depletion is no greater than one-half of the net income before depletion as stipulated in IRS regulations.

lease. It also represents the residual economic rent to the resource. The relevance of this variable to better decisions and government policy is discussed in more detail below.

Once the after tax net present value is determined for a particular q_o, other output variables associated with that ATNPV are stored. The model then checks to determine if all q_o or T values have been evaluated. If not the model returns to the beginning of the q_o-T loop and repeats the procedure outlined above. If all possible T values or all input q_o values have been evaluated, the model then proceeds to select the optimal q_o-T combination for this Monte Carlo iteration. The optimal set is the one with the highest ATNPV. This optimal ATNPV is then compared with the potential tax write-off calculated earlier during the exploration phase. If the ATNPV is greater than the potential tax write-off the optimal ATNPV value is stored as the result for this iteration. If the potential tax write-off from not developing the lease is greater than the potential gain from developing the lease (ATNPV), the decision is made not to develop the lease and the exploration loss is entered into the after tax net present value register. A zero is entered into the register for other output variables such as production, production time horizon, profit share, royalty, and tax. This result corresponds to the real world situation in which some quantity of resource is discovered during the exploration phase but the economics dictate that the quantity is so small that it is not commercial and the lease is not developed.

Monte Carlo Results and Model Outputs: With the final values of all output variables determined for this Monte Carlo iteration, the model then checks to see if all Monte Carlo iterations specified have been completed. If not, the model returns to the beginning of the Monte Carlo simulation and repeats the entire process. If all the Monte Carlo iterations have been completed, then the mean, standard deviation, and other statistics on each output variable are calculated. If desired, histograms can be constructed for after tax net present value (ATNPV) and reserves. The histograms illustrate the distribution of output for these two variables. The distribution of after tax net present value provides the range of potential outcomes and the frequency with which each outcome occurs.

In the above described model, economic rent is composed of royalty and profit share payments, tax payments, and the after tax net present value (ATNPV). These rent components can be manipulated in the model to determine expected bidding behavior and associated impacts for various leasing policy alternatives. For example, in a bonus bidding system with a fixed royalty rate, the expected bonus bid is a function of after tax net present value.[31] The sum of the bonus bid, royalty income, and taxes is equal to total economic rent.

Under a royalty bid system, the winning bid would be expected to be the one which eliminates after tax net present value. In other words, when after tax net present value is constrained to equal zero, royalty payments and

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[31] Actual bonus bids are a result of bidding strategies formulated from game theoretic approaches combined with bidders estimates of lease value.

taxes alone would compose economic rent, and the royalty bid rate can be determined. Hence, the discounted value of cumulative royalty payments and taxes equals the anticipated economic rent.

One of the policy options programmed into the model is the ability to determine what the royalty bid rate would be under the above assumptions. In addition to the fixed royalty and royalty bid option, sliding scale royalty systems are also incorporated into the model. Under these systems, the royalty rate in each period is a function of the amount or value of production in that period. These systems attempt to capture rent due to economies of scale and to prevent early termination of production by varying the royalty rate directly with the level or value of production. Similarly, a variable profit share system is incorporated into the model which allows the profit share rate to vary in each production period with the amount of profit in that period.

A number of other profit share systems are also included in the model. A capital recovery system, which provides for recovery of capital at a specified rate of interest over a predetermined time period before the government takes its profit share, is one of the profit share variations. Also, a profit share system based on the British profit share plan is included (see Chapter III for an expanded discussion of these options).

The model is also programmed to handle any of three variations of advanced royalty payments. Specific advanced royalty systems with the advanced royalty based on either a certain value per unit of output or a certain percentage of the gross value at the point of the lease are two of the advanced royalty options. A third advanced royalty option (ad valorem) provides for collecting advanced royalties at a predetermined rate based on the actual price prevalent throughout the production period. In conjunction with any of the advanced royalty systems an exogenous delay in production may be input to the model and the effects of any of the advance royalty systems with alternative input values determined. Alternatively, changes in the expected production delay caused by different advanced royalty parameters or price expectations may be evaluated.

Summary: Clearly a wide range of leasing policy options including bonus bidding systems, royalty systems, profit share systems, and a number of combinations of these systems and their many variants may be analyzed with the generalized leasing model. In addition to the wide range of leasing policy options, a number of tax policy options are also included in the model. General policy options such as price subsidies, purchase guarantees, price supports, investment subsidies and other policy options designed to increase certainty for private investors are also included. Furthermore, other tax policy, general policy, or leasing policy options can easily be incorporated in the model framework.[32] Hence, the model is ideally suited for analysis of a wide range of government policy options dealing with the disposition of federally owned natural resources.

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[32]For example, model outputs from individual evaluations may be combined to simulate lease sales through time. This approach is used to determine the impacts through time of alternative leasing strategies.

Outputs of the basic model include statistics on the following variables: production time horizon, installed capacity, present value of royalty payments, present value of depletion, present value of taxes, present value of profit share payments, production, reserves, total production cost, and after tax net present value. Additional outputs are provided for specialized leasing or other policy options such as the royalty bidding system.

The use of Monte Carlo simulation with uncertain variables provides an additional dimension to government policy analysis. Not only can the change in expected value of model outputs be determined when a policy variable is changed, but also the change in variance of the model outputs can be determined. This information may be quite useful for government policy makers attempting to influence private sector decisions. In addition, the simulation process more closely approximates the decision making procedure used in the private sector when evaluating potential resource investments.

This model description has been both detailed and comprehensive. The aim has been to give the reader a thorough understanding of not only the rationale behind the model algorithm, but also an understanding of the actual equations and decision functions utilized in the programmed version of the model. All too often, the links between theory and computational forms used in models are not clearly established and readers and model users must tediously grope through the description to provide these links on their own. It is our hope that through providing a complete description of the model mechanism that readers and users will be better able to utilize the model results and to properly establish the links between these model results and informed policy analysis.[33]

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[33]The computer code and more detailed operating instructions are both available from the authors for the interested reader.

Chapter V

Costs of OCS 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 production 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 OCS production possibilities.[34]

Production Cost Concepts: Economists normally classify costs of any process, such as extracting hydrocarbons, as 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 hydrocarbon 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.

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[34]Portions of the discussion are based on or taken from a previous work by the authors (Kalter, *et al.*, 1974, Ch. II).

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 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 of 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. 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 appropriate 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, exploration and 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. Based on historical experience in the Gulf and in the Continental United States, it will be assumed that eighty percent of the recoverable gas reserves are non-associated and twenty 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 (NGL) in the Gulf has been somewhat higher for non-associated gas than for associated gas, the NGL production in the OCS will be assumed proportional to natural gas production. For associated natural gas, the NGL production will be included with the oil production and not measured separately. (This assumes NGL and oil prices are equal). For non-associated natural gas, a factor of .033 barrels of NGL per Mcf of natural gas will generally be used (see Chapter II). This proportion is derived from the parameters used by the USGS in its reserve estimates and from Spivak and Shelburne (p. 1308) in their analysis of recoverable AOCS hydrocarbons.

The costs of producing associated and non-associated gas and natural gas liquids will be handled differently. When oil is the primary product, the incremental cost of producing associated natural gas and NGL is small and will be assumed negligible in this analysis. For non-associated natural gas, production costs will be based upon appropriate modifications of the components pertaining to oil reservoirs.

Third, primary recovery costs, for the various hydrocarbon associations, will be different due to locational factors (such as weather). Production costs appropriate for each OCS area are needed for this study. Based on National Petroleum Council data (NPC, Ocean Petroleum Resources, 1975), we have estimated exploration, development, and operating costs for each of five cost regions to be used in this analysis. The procedures used in deriving these cost estimates are explained below.

Selection of NPC data as the basis for our cost estimates was based on a thorough review of available cost information conducted for a previous paper (Kalter, et al., 1974). In that paper, we compared NPC based estimates with estimates derived from agency studies within the Department of Interior (USDI, Bureau of Mines, 1972; USDI, BLM, 1970). We found the magnitudes of NPC based estimates roughly corresponded to those of other estimates, yet offered significant advantages. That is, the NPC estimates were computed for three different reservoir sizes and were based on 1974 cost figures. Furthermore, NPC petroleum engineers made an effort to provide extrapolation factors from their base case (Gulf of Mexico) to other cost areas. In this paper, we have continued to use NPC data as the basis for our cost estimates, but we have modified the procedures and assumptions somewhat as will be explained below.

Investment Costs - Oil and Associated Natural Gas: 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.

Exploration Costs: Generally all exploratory activities, beginning with geophysical and geological 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 ten percent or less, meaning that ten percent of the exploratory wells are successful in locating commercial hydrocarbon deposits (American Petroleum Institute, Quarterly Review, 1974).

In estimating OCS 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. The number of exploratory wells drilled per 1000 acres of lease area is an input to the analytical model (Chapter IV) and may vary by area. The composition of the exploration well costs is given in Table 11. Note that the values are in 1974 dollars. To bring the costs up to date, a fifteen percent inflation factor was assumed for all costs (exploration and development).

Table 11.--Base Case Exploratory Drilling Expenditures Per Well

Item	Amount (millions of dollars)
Drilling Expenditures - Day Rate of $27 M/D x 80 Drill Days (10-12,000 Foot Well)*	$2.160
Equipping Expenditures - Day Rate of $27 M/D x 7 Equipping Days	.189
Tubular Goods	.264
Wellhead	.050
Testing	.026
Other	.025
Total Per Well Drilling and Equipment Expenditures	$2.714

Note: The Base Case is for 200 meters water depth, moderate climate, expressed in thousands of 1974 constant dollars.

*The day rate is directly related to the cost of the rig and is intended to cover depreciation, insurance, interest expense, variable general and administrative expense, direct operating expense and a financial return to the rig owner. A rig capital cost of $20 million is assumed.

Source: National Petroleum Council, Ocean Petroleum Resources, 1975, p. 24.

To determine the variation in exploration (and development) cost by region, NPC used cost factors which varied with climate. We have modified the original NPC cost factors and regions somewhat in producing the cost factors found in Table 12.[35]

Table 12.--Cost Regions Used in the OCS Analysis

Region Number	Region Name	Areas Used	Exploration Cost Factor	Development Cost Factor
1	moderate	Gulf of Mexico South Atlantic South Pacific	1.0	1.0
2	moderate-severe	Central Atlantic North Pacific	1.4	1.9
3	severe	North Atlantic Gulf of Alaska	1.8	2.8
4	ice laden	Bering Sea, Alaska	2.3	3.7
5	severely ice laden	Chukchi Sea Arctic Ocean	4.6	4.6

Exploration costs per well in 1975 dollars by cost region are found in Table 13. These costs, and all other costs in this paper, assume 200 meters of water depth. They could be somewhat lower for shallower depths but would increase significantly for deeper water areas. No attempt is made to analyze the economics of hydrocarbon production in very deep water.

Table 13.--Exploration Costs Per Well by Cost Region

Cost Region	Cost per Well (millions of 1975 dollars)
1	3.121
2	4.370
3	5.618
4	7.179
5	14.357

[35] A third category was defined (moderate-severe) which included the Central Atlantic and the North Pacific. Cost estimates for this region were assumed to be the midpoint of two climatic conditions -- moderate and severe. In addition, development costs for ice laden and severely ice laden regions

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 OCS.

Several studies have estimated development costs, by component, for the Gulf of Mexico (NPC, 1975; USDI, Bureau of Mines, 1972; USDI, 1970). Using adjusted NPC data, the total costs for a two platform producing system in the Gulf are provided in Table 14. NPC engineers assumed that this producing

Table 14.--Gulf of Mexico Development Costs (200 meter water depth)

Cost Component	$ in millions (1974)
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

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

system would be used for oil reservoirs ranging in size from 25 to 175 million barrels. Although the resulting estimates are acceptable for reservoir sizes within that range, they are not acceptable for reservoir sizes significantly smaller (where only one platform would be used) or significantly larger (where more than two platforms would be used). Consequently, we have developed cost estimates for additional producing systems utilizing one, three and four platforms (based on the original NPC data). Table 15 details these estimates for the four producing systems used in this analysis.

To determine cost per unit of installed capacity, the initial production of each system on each reservoir size must be determined. Table 16 lists the assumptions used in this analysis, some of which were adapted from the original NPC assumptions (NPC, p. 32, 1975). Obviously, these assumptions are somewhat arbitrary and will not apply across all reservoir conditions. In particular, some of the installed peak capacities are near the maximum that could be expected for the given reservoirs (such as the NPC 25 and 65 million barrel fields). Nonetheless, these assumptions should give reliable estimates of cost per unit of installed capacity by reservoir size.

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were not given by NPC. Therefore, we assumed a linear extrapolation from those provided.

Table 15.--Development Costs for Four Producing Systems
(1974 dollars in millions)

Cost Component	Number of Platforms			
	1	2 (base)	3	4
Platforms	$15.0	$30.0	$45.0	$60.0
Wells	10.0	20.0	30.0	40.0
Pipeline	15.0	18.0	22.0	29.0
Production Facilities	5.0	10.0	15.0	20.0
Storage	2.0	2.0	3.0	4.0
Future field improvements and abandonment	3.0	3.4	5.0	7.0
Totals	$50.0	$83.4	$120.0	$160.0

Table 16.--Producing Characteristics of Petroleum Reservoirs

Producing Characteristics	Reserves (million barrels)					
	15	25	65	175	525	1050
Installed capacity (mB/year)	2.956	5.913	11.826	17.739	47.304	118.260
Years at peak capacity	1	1	2	3	3	3
Decline rate (%/year)	.23	.23	.21	.13	.11	.13
Depletion period	13	8	9	20	23	15
Number of platforms	1	2	2	2	3	4

The next step in determining cost per unit of installed capacity was to divide the total development costs (from Table 15) by the installed capacities (from Table 16). The costs by reservoir size were then inflated to 1975 dollars and multiplied by the development cost regional factors (from Table 12). The resulting range of calculated development costs per unit of installed capacity by reservoir size is found in Table 17.

If the reservoir sizes found in Table 17 were the only size reservoirs we desired to analyze, the investment cost calculations could end at this point. However, in the Monte Carlo analysis with uncertain reserves, a reserve sample pick is selected for each iteration from an assumed lognormal distribution of reserves. Hence, across all OCS provinces, reserve sizes to be analyzed will vary almost continuously over a very wide range. Therefore, we attempted to fit the reserve size and cost data from Table 17 to a functional form to allow development cost to vary continuously with reserve

Table 17.—Calculated Development Costs by Reservoir Size

Reservoir Size (million bbls.)	Cost Region					
	1 (1974 $)	1 (1975 $)	2	3	4	5
15	$16.91	$19.45	$36.95	$54.45	$71.95	$89.45
25	14.10	16.22	30.81	45.40	60.00	74.59
65	7.05	8.11	15.40	22.70	30.00	37.29
175	4.70	5.41	10.27	15.13	20.00	24.86
525	2.54	2.92	5.55	8.18	10.81	13.44
1050	1.36	1.55	2.97	4.38	5.79	7.19

size. For all cost regions, we found that a power curve functional form fit the data quite well. The power curve is of the form shown in equation (38):

$$C = aR^b \tag{38}$$

where R is reserves, C is cost per unit of installed capacity, and a and b the equation coefficients. By writing equation (38) in log form, the coefficients can be found by linear regression. Equation (39) represents the log form:

$$\ln C = \ln a + b \cdot \ln R \tag{39}$$

Table 18 provides the results of fitting cost data for each cost region to the power curve.

Table 18.—Cost Power Curve Results by Cost Region

Result	Cost Region				
	1	2	3	4	5
a	296,472	549,473	807,966	1,066,644	1,329,842
b	-.57958	-.57818	-.57805	-.57799	-.57816
R^2	.99	.99	.99	.99	.99

Because the resulting b values were so similar, we decided to use an average b value for all cost regions (given the uncertainty in the original numbers). Hence, the b value for the cost power curve is -.57839. The computer program selects an a value according to cost region and then generates a unique cost value for each iteration based on the reserve sample selection for that iteration. Table 19 provides the cost values for the selected reservoirs generated using the cost power curve function.

Table 19.--Cost by Reservoir Size Generated by the Power Curve (1975 Dollars)

Reserve Size (million bbls.)	Cost Region				
	1	2	3	4	5
15	$20.96	$38.85	$57.12	$75.41	$94.02
25	15.60	28.91	42.51	56.12	69.97
65	8.98	16.64	24.46	32.29	40.26
175	5.06	9.38	13.79	18.21	22.70
525	2.68	4.97	7.31	9.65	12.03
1050	1.80	3.33	4.89	6.46	8.05

These costs are calculated as dollars per unit of installed annual capacity. To convert these data to "new daily barrel" cost often used in industry, multiply the given cost by 365. For example, the "new daily barrel" development cost for a 175 million barrel reservoir in the Baltimore Canyon (Region 2) would be $3424.

Operating Costs - Oil and Associated Natural Gas: Average operating costs for the primary recovery of petroleum have been estimated as about $.50 per barrel (as of 1970) in the Gulf of Mexico (USDI, 1970; Weaver). NPC estimated average operating costs over the production period at $.97/barrel (NPC, p. 90, 1975). As the 1975 initial operating cost for the moderate cost region (Gulf of Mexico), we will use $.40 per barrel of initial production capacity. Operating cost would be expected to vary among cost regions but not by as much as exploration or development costs. For purposes of this analysis, we will assume that operating costs vary among cost regions at one-third the rate of development costs. Using this assumption, Table 20 provides the initial and average operating costs for oil and associated natural gas by cost region. Operating costs per unit are assumed to be constant, not to vary with reservoir size or installed capacity.

Table 20.--Operating Costs by Sub-region

Cost Region	Initial Operating Cost ($/barrel)	Average Operating Cost ($/barrel)*
1	$.40	$ .93
2	.52	1.21
3	.64	1.49
4	.76	1.76
5	.88	2.04

*Assuming a fifteen year production time horizon, decline rate of ten percent and $\theta = 0$.

Investment Costs - Non-associated Natural Gas: As with oil reservoirs, a number of factors make up the investment costs required to obtain production from non-associated natural gas fields. Again, we can divide these costs into the two categories of exploration and development.

Since it is highly unlikely that oil and non-associated natural gas reservoirs will ever be found together on a common leasehold, one can postulate that the same amount of exploration activity will be required to find either type of energy source. Thus, exploration expenses for natural gas cannot be assumed to be joint with those estimated for oil. On the other hand, the amount of exploration activity and its cost should be no different than that estimated for oil (by cost region and water depth). We will, thus, assume that the values displayed in Tables 11 through 13 are applicable to natural gas.

Development cost for non-associated gas, however, 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 components (such as transportation) would be reduced (Garett, 1974). For purposes of approximating the gas development costs, we make the following assumptions:

1. Gas reservoirs comparable to the oil reservoirs used above are six times (AAPG, 1975) the size of the oil reservoirs (in Mcf).

2. The number of platforms (and wells) needed to develop the gas is reduced by one platform over the oil case (except for the smallest reservoir where one platform with fewer wells is still required).

3. The initial capacity of the gas production is set at two thirds of the equivalent oil production. In other words, the oil production values were multiplied by 4 (.67 x 6). Gas production generally occurs at lower (relative) levels than oil and proceeds for longer periods.

Using these assumptions, the base values for gas investment cost were calculated and are displayed in Table 21.

Table 21.--Base Case Gas Investment Costs

Reserves (million Mcf)	Initial Capacity (million Mcf)	Cost (million $)	1974 Base ($/Mcf)	1975 Base ($/Mcf)
90	11.824	40	3.38	3.89
150	23.652	50	2.11	2.43
390	47.304	50	1.06	1.22
1050	70.956	50	.70	.81
3150	189.216	83.4	.44	.51

These costs were extrapolated to the other four cost regions as was done for oil. Similarly, a power curve was fit to the data, and the values shown in Table 22 represent costs by region and reservoir size generated from the power function.

Table 22.--Gas Investment Costs Using the Power Function

Reserves (million Mcf)	Cost Regions ($/Mcf)				
	1	2	3	4	5
90	$3.28	$6.48	$9.39	$12.31	$15.47
150	2.46	4.86	7.05	9.24	11.62
390	1.44	2.85	4.12	5.40	6.79
1050	.83	1.63	2.36	3.10	3.90
3150	.45	.88	1.28	1.67	2.10

Readers should note that these cost estimates have not been evaluated as thoroughly as the oil costs and may be subject to error.

Operating Costs for Non-associated Natural Gas: Operating costs ranged from $.04 to $.06 per Mcf in the Interior study (Department of the Interior, 1970, pp. 206-208). For the Gulf of Mexico (cost region one), an initial operating cost of $.04 per Mcf will be used. Costs for other regions, calculated in the same manner as for oil, are shown in Table 23.

Table 23.--Operating ¯ .ts for Non-associated Natural Gas

Cost Region	Initial Operating Cost ($/Mcf)
1	$.04
2	.05
3	.06
4	.08
5	.09

As was assumed for oil, operating costs are assumed not to vary with reservoir size. Costs for natural gas liquids are assumed to be included in the natural gas costs (both operating and investment).

Summary: Tables 24 and 25 summarize the values which are used in this analysis for oil and natural gas investment and operating costs.

Table 24.--Oil Costs: Summary

Reservoir Size	Cost Regions				
	1	2	3	4	5
15	$20.96	$38.85	$57.12	$75.41	$94.02
20	15.60	28.91	42.51	56.12	69.97
65	8.98	16.64	24.46	32.29	40.26
175	5.06	9.38	13.79	18.21	22.70
525	2.68	4.97	7.31	9.65	12.03
1050	1.80	3.33	4.89	6.46	8.05
Exp. Costs per well (in millions)	3.121	4.370	5.618	7.179	14.357
Operating Costs (initial)	.40	.52	.64	.76	.88

Table 25.--Non-associated Natural Gas Costs: Summary

Reservoir Size	Cost Regions				
	1	2	3	4	5
90	$3.28	$6.48	$9.39	$12.31	$15.47
150	2.46	4.86	7.05	9.24	11.62
390	1.44	2.85	4.12	5.40	6.79
1050	.83	1.63	2.36	3.10	3.90
3150	.45	.88	1.28	1.67	2.10
Exp. Costs per well (in millions)	3.121	4.370	5.618	7.179	14.357
Operating Costs (initial)	.04	.05	.06	.08	.09

Chapter VI

Comparison of Alternative OCS Leasing Systems and Schedules

With the widespread current interest in OCS leasing activity, increased attention has been focused on alternative leasing systems and schedules for public OCS areas. This chapter is divided into two parts -- the first provides a comparison of the alternative leasing systems and the second examines the impacts of alternative leasing schedules.

Part I

Alternative Leasing Systems

Theoretical differences among several alternative systems were discussed in Chapter III. This section provides the conclusions of our empirical analysis of those systems. The first step in this discussion is to define the specific systems which were subjected to analysis. Secondly, assumptions and data that are common to all leasing systems tested are outlined, and finally, the analytical results are presented and the alternative systems are compared using several evaluation criteria.

Systems Evaluated: The current cash bonus system is used in the analysis as the standard against which alternative systems are compared. The cash bonus system presently utilizes a fixed royalty rate of 16.67 percent with the remainder of government revenue coming from taxes and the bonus payment. The bonus amount is the bid variable under the system. In fact, each of the alternative systems tested for this paper uses the cash bonus as the bid variable. However, the systems differ significantly in the importance of the bonus payment relative to contingency payments.

The systems which were analyzed, and are normally classified as contingency systems, are as follows:

1. Cash bonus with a higher fixed royalty -- Alternative royalty rates were tested beginning with 20 percent.

2. Cash bonus with a variable royalty rate -- The royalty rate was structured to vary with production levels and value of production.[36] In the

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[36] The variable rate structures generally were designed to capture a greater proportion of total economic rent on highly profitable fields and a smaller proportion on marginal fields. Consequently, they were designed so that the marginal field ATNPV values with the variable rate systems would be somewhat higher than the ATNPV values for the comparable fixed rate contingency systems. Similarly, for the highly profitable production situations, the rate structures were designed so that the ATNPV would be lower than the cash bonus system and generally lower than the comparable fixed rate contingency system.

former case, the rate was set at fifteen percent up to three million barrels and increased one percent for each incremental two million barrels of annual production up to a maximum of 40 percent. For example, an annual production level of twenty-five million barrels would result in a royalty rate of twenty-six percent. For non-associated natural gas fields, the initial rate of fifteen percent held for production up to twenty million Mcf per year and the rate increased one percent for each incremental ten million Mcf of annual production up to a maximum of forty percent. For this rate structure, annual production of 100 million Mcf would result in a royalty rate of twenty-three percent. For the system in which the royalty rate varied with the value of production, the minimum rate of five percent applied for production values of up to $10 million annually and the rate increased one percent for each incremental $5 million in production value up to a maximum of fifty percent. If the annual gross revenue (value of production) were $100 million, the applicable royalty rate would be twenty-three percent.

3. Cash bonus coupled with a profit share calculated on a taxable income (IRS) base -- In this system, a profit share is deducted from taxable income before taxes. A number of rates were tested beginning with twenty percent.

4. The IRS base profit share system with a variable rate -- For the variable rate profit share system, the rate for each year changes with net income. The minimum rate of twenty percent applies in any year in which net income (the profit share base) is up to $10 million per year. The rate increases one percent per incremental $2 million of annual profits up to a maximum of eighty percent. For example, annual profits of $40 million would result in a profit share rate of thirty-five percent. The rate is recalculated for each year of production.

5. Annuity capital recovery profit share system with a cash bonus bid -- Under the capital recovery system, a portion of the initial investment plus interest are allowed to be deducted each year from the profit share base before the government's profit share is computed. This deduction is computed by converting all investment costs plus interest to the beginning of production into an annuity using eight years and eight percent as time and interest values. The value of this annuity (plus any carryover) is subtracted from the profit share base before computing the government's profit share.[37] A range of rates was tested for this system, beginning at thirty percent.

6. Variable rate capital recovery profit share system with bonus bid -- The same profit share variable rate structure as described above was utilized.

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37 For both the annuity capital recovery and the British capital recovery systems, normal expensing and depreciation of investment was allowed. Although this amounts to allowing double recovery of capital, the approach was taken because any alternative would probably require a change in the IRS code as well as leasing laws. Sensitivity tests were conducted on a limited scale in which expensing and depreciation of investment were disallowed. The results showed that the numerical values changed significantly, but the overall system results appeared similar. More study needs to be conducted on this aspect of capital recovery systems.

7. British type capital recovery system with a bonus bid -- In this type of profit share system, all of the initial capital investment times some factor (for this analysis, 1.5) is deducted from the profit share base before any profit share is taken. This approach results in no profit share being taken by the government in the early years of production. A range of rates beginning with thirty percent were tested for this system.

8. British type capital recovery system using a variable rate with a bonus bid -- The same variable rate structure as described above is employed.

All of the profit share systems described used a zero royalty rate, and the royalty and cash bonus systems used a zero profit share rate. Obviously, a number of combinations of the above systems could be designed and subjected to analysis. This task was not undertaken as a part of this study because our primary focus was to determine the major impacts caused by key features of the alternative systems.

Assumptions and Data: Table 26 gives the values for variables which are common to all the tests conducted. The values which change by lease system were provided above, and those which vary for other reasons are provided in Chapter II (geologic inputs) and Chapter V (costs). Complete definitions of the variables and explanations for usage are found in Chapter IV (model description).

Several of the data assumptions listed in Table 26 are particularly important. First, a uniform production decline rate of ten percent was assumed for all tests. Clearly, this assumption is not generally valid. However, in the absence of better information, it was considered the best alternative and representative of average conditions. Second, the mean of the annual price change distribution was set equal to zero for both oil and natural gas. This assumption implies that the expected real prices of these resources would not change through time (although the actual sample prices would). Third, a development lag of five years, including a two year exploration period, was assumed for all tests. Although the development period would probably fall through time as activity proceeded in a given region, we have no way of estimating the rate or extent of the change so uniform development and exploration periods were assumed.

Another assumption, utilized for the leasing system comparison, is that there are no short run equipment or manpower constraints. No institutional restrictions on the rate of production were included, other than any effect implicitly included in the minimum allowable production time (ten years). In addition, the primary focus of the leasing systems evaluation will be a comparison of the alternative systems as applied to oil reservoirs with associated natural gas. The results should not be significantly different for nonassociated natural gas reservoirs, but tests were conducted to verify this presumption.

Analytical Results: In detailing analytical results, we will first consider the question of lease system viability under economically marginal conditions (given certain combinations of production costs, price and reserves). Then, we turn to the possibility of more profitable production circumstances.

Table 26.--Common Input Values for Leasing Policy Analysis

Geologic	
Production decline rate, a	.10
Beta (recovery factor), β	.50
Reserve distributions	lognormal
Price related	
Original oil price, P_o	\$11.00, \$13.00 and \$16.00
Original gas price, GP_o	\$.60, \$1.50 and \$2.00
Mean of oil price change distribution, RP1MN	0
Std. dev. of price change distribution, RP1STD	.04
Mean of gas price change distribution, GP1MN	0
Std. dev. of price change distribution, GP1STD	.05
Tax related	
Depreciation method, NDEPR	Sum of Years Digits
Depreciation lifetime, N	15 years
Percent investment salvageable, α	10%
Investment tax credit rate, Ω	10%
Federal corporate tax rate, ϕ	48%
Time related	
Minimum production time, TMIN	9 years
Years of flat production plus production build up, FLATP	5 years
Maximum production period, TMAX	40 years
Development and exploration period, LAG	5 years
Exploration period, LAG1	2 years
Production build up period, IBP	2 years
Production build up factors, BPP	
year 1	.5
year 2	.8
Cost related	
Working capital factor, WCF	.1
Triangular investment and operating cost contingency distributions	
BMIN, KMIN	-.05
BMODE, KMODE	0
BMAX, KMAX	.1
Rent per acre, RENT	\$3.00
Investment cost allocation during development, F	
year 1	0
year 2	.1
year 3	.3
year 4	.4
year 5	.2

Table 26.--Continued

Percent investment each year that is tangible, YZ	
year 1	0
year 2	.7
year 3	.7
year 4	.8
year 5	.8
Exploration cost allocation during exploration, F1	
year 1	.4
year 2	.6
Percent exploration cost tangible each year, YZ1	
year 1	0
year 2	.3
Other Factors*	
Discount rate	.12
No. of exploratory wells per 1000 acres	.5
No. of acres per tract, ACRES	5760
Bonus factor, BFAC	.75
No. of M. C. iterations, NLOOP	200

*All of the following variables were set equal to zero: SUB, BCON, θ, z, GPMIN, BYPRCD, ALAMB, CHALMB, ST, NQO, PMIN, MPI, SUBI, MCR.

Viability of Alternative Leasing Systems: The first objective of this analysis was to determine the effect of each leasing system, and the associated contingency rates, in marginal producing areas; that is, those areas where costs of production are very high in relation to anticipated revenues. Given the physical factors of production and the current institutional framework (taxes, etc.), three factors that influence the economic viability of a given hydrocarbon discovery are reserve size, production costs, and market prices. Consequently, we tested various field discovery sizes under alternative cost conditions over a range of oil and natural gas prices to determine which fields were economic under the current leasing system. Three field sizes (small, medium and large) based upon the analysis contained in Chapter II, above, were used, along with relevant costs for the various NPC cost regions (see Chapter V). Both oil and non-associated natural gas fields were evaluated.

Using a positive ATNPV as the economic development criterion[38], we determined which field sizes could be developed in each cost region for each set of prices. Three sets of prices were tested: 1) $11.00 per barrel for oil and $.60 per Mcf for natural gas, 2) $13.00 per barrel for oil and $1.50 per Mcf for natural gas, and 3) $16.00 per barrel for oil and $2.00 per Mcf for natural gas. Interestingly, the petroleum field size development pattern by cost region did not change over the entire range of prices tested. Table 27 shows that pattern when using the current cash bonus system by field size for three selected cost regions. The cost regions shown were also used for the

Table 27.--Oil Field Development Pattern by Field Size and Cost Region*

Cost Region	Field Size		
	Small	Medium	Large
5	no	no	yes
3	no	yes	yes
1	yes	yes	yes

*This pattern was essentially the same for natural gas fields when the cash bonus leasing system was utilized.

38 Alternative criteria could be employed which take the degree of risk into consideration, but this approach was selected to simplify comparisons among systems and leasing conditions.

analysis of alternative leasing systems under marginal economic conditions since they represented the range of cost conditions that can be expected throughout the OCS. The following field size-cost region combinations were used:

1. Large field in cost region 5, province 1,
2. Medium field in cost region 3, province 11, and
3. Small field in cost region 1, province 8.

Since the lowest set of prices tested yielded the least economic rent, the $11.00 per barrel oil and $.60 per Mcf natural gas prices were used in the marginal analysis.

Table 28 displays the results of the model simulations for each of the alternative systems when used in the three economically marginal operating areas. listed above. For each of the contingency systems, the highest contingency rate (in ten percent intervals) that could be used in all three areas while permitting profitable development was employed. The variable rate structures also were designed to be viable in each of the marginal producing situations.[39] In general, the analysis showed that any of the alternative leasing systems could be used effectively in marginal areas if the contingency rates were properly set.

However, in comparing alternative systems, both in marginal and in more profitable production situations, evaluation criteria are needed. For this analysis five criteria were selected:

1. Government revenue,

2. Total expected production,

3. Chance of a less than normal profit,

4. Bonus ratio -- ratio of the ATNPV of each system to that of the current cash bonus system, and

5. Ratio of the mean ATNPV to the standard deviation of ATNPV.

Changes in these indicators were noted for all systems with the current cash bonus system serving as the standard of comparison. The first measure, government revenue, is an indicator of the efficiency of each system in terms of revenue collection. However, the measure does not make differential

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39 One exception is the variable rate profit share structure which produced no development for the large field in cost region 5 using the IRS profit share base.

Table 28.--Results of Leasing Model Simulations Using Economically Marginal Petroleum Fields in Representative Production Cost Areas*

Alternative Leasing System	Contingency Rates		Economic Impacts					Physical Factors			Evaluation Criteria					
	Royalty Rate (%)	Profit Share Rate (%)	ATNPV (P.V.-mil. $)	Tax (P.V.-mil. $)	Royalty (P.V.-mil. $)	Profit Share (P.V.-mil. $)	Total Econ. Rent (P.V.-mil. $)	Mean Disc. Size (mil. bbls.)	Instld. Cap. (mil. bbls.)	Prod. Time Horizon (years)	Govt. Rev. (bonus=.75x ATNPV)	Expec. Oil Prod.	Expec. Nat. Gas Prod.	Chance of Less than Normal Profit(%)	Bonus Ratio	Mean ATNPV / S.D. ATNPV
Large Reservoir Discovery in Cost Region 5 (Province 1)																
Current Cash Bonus	16.67	0	13.1	47.9	37.8	0	98.8	262.5	28.4	13.1	95.5	61.2	35.7	75.5	1.0	.14
Royalty - Fixed	20.0	0	8.6	42.4	42.4	0	93.4	277.9	30.2	12.9	91.3	56.8	33.2	78.5	1.5	.10
Royalty - Variable with Production	15-40	0	1.1	33.2	48.9	0	83.2	271.4	23.7	17.4	82.9	58.6	34.3	77.5	12.0	.02
Royalty - Variable with Value	5-50	0	23.7	59.8	22.3	0	105.8	235.0	24.0	13.3	99.9	69.5	40.6	69.0	.6	.23
Profit Share																
IRS Base	0	30.0	4.2	37.3	0	48.0	89.5	285.2	30.6	13.2	88.4	54.3	31.7	80.0	3.1	.05
IRS Base	0	20-80				No Development										
Capital Recovery	0	50.0	6.3	44.0	0	54.3	104.6	250.1	28.8	11.3	103.0	64.0	37.4	73.0	2.1	.09
Capital Recovery	0	20-80	14.0	46.1	0	38.2	98.3	241.6	23.9	12.7	94.8	66.9	39.1	71.0	.9	.20
British	0	60.0	1.2	38.0	0	58.0	97.2	275.1	33.7	9.5	96.9	57.2	33.4	78.0	11.4	.02
British	0	20-80	8.9	44.6	0	41.9	95.4	235.0	21.2	14.9	93.2	69.9	40.8	69.0	1.5	.15
Medium Reservoir Discovery in Cost Region 3 (Province 11)																
Current Cash Bonus	16.67	0	5.9	19.0	15.2	0	40.1	94.4	10.0	12.6	38.7	23.8	27.4	73.5	1.0	.17
Royalty - Fixed	20.0	0	3.7	17.8	17.6	0	39.1	94.0	9.7	13.6	38.1	23.3	26.8	74.0	1.6	.12
Royalty - Variable with Production	15-40	0	5.1	18.0	16.2	0	39.3	92.7	9.0	14.1	38.1	24.4	28.1	72.5	1.1	.17
Royalty - Variable with Value	5-50	0	3.7	15.8	16.0	0	35.6	88.6	7.1	19.6	34.7	26.1	30.0	69.5	1.6	.17
Profit Share																
IRS Base	0	30.0	1.6	15.5	0	20.6	37.7	96.0	9.8	13.8	37.3	22.4	25.9	75.5	3.6	.06
IRS Base	0	20-80	2.9	15.3	0	18.1	36.3	94.6	8.6	15.3	35.6	23.6	27.2	74.0	2.1	.12
Capital Recovery	0	50.0	3.7	17.8	0	20.8	42.3	92.0	10.9	10.1	41.4	24.4	28.1	72.0	1.6	.14
Capital Recovery	0	20-80	9.9	23.2	0	11.7	44.8	86.3	9.7	11.0	42.4	26.6	30.6	67.5	.6	.29
British	0	60.0	1.9	16.5	0	22.9	41.3	94.4	11.7	9.0	40.8	23.6	27.2	73.5	3.1	.08
British	0	20-80	9.3	22.5	0	12.5	44.3	86.7	9.7	11.1	42.0	26.4	30.4	68.0	.6	.28

Table 28.--Continued

Alternative Leasing System	Contingency Rates		Economic Impacts					Physical Factors			Evaluation Criteria					
	Royalty Rate (%)	Profit Share Rate (%)	ATNPV (P.V.-mil. $)	Tax (P.V.-mil. $)	Royalty (P.V.-mil. $)	Profit Share (P.V.-mil. $)	Total Econ. Rent (P.V.-mil. $)	Mean Disc. Size (mil. bbls.)	Instld. Cap. (mil. bbls.)	Prod. Time Horizon (years)	Govt. Rev. (bonus= .75x ATNPV)	Expec. Oil Prod.	Expec. Nat. Gas Prod.	Chance of Less than Normal Profit	Bonus Ratio	Mean ATNPV / S.D. ATNPV
Small Reservoir Discovery in Cost Region 1 (Province 8)																
Current Cash Bonus	16.67	0	3.2	8.5	6.9	0	18.6	22.7	2.6	10.7	17.8	10.9	2.4	48.5	1.0	.31
Royalty - Fixed	20.0	0	2.2	7.6	7.8	0	17.6	23.2	2.6	10.9	17.1	10.3	2.3	53.0	1.5	.23
Royalty - Variable with Production	15-40	0	3.7	9.0	6.5	0	19.2	22.3	2.6	10.6	18.2	11.3	2.5	46.5	.9	.35
Royalty - Variable with Value	5-50	0	7.0	11.8	2.4	0	21.1	21.0	2.5	9.8	19.4	12.5	2.8	37.0	.5	.55
Profit Share																
IRS Base	0	30.0	.8	6.4	0	9.1	16.2	24.1	2.7	11.2	16.0	9.6	2.1	58.0	4.0	.10
IRS Base	0	20-80	3.0	8.4	0	7.5	18.9	22.4	2.5	11.0	18.1	11.2	2.5	47.0	1.1	.32
Capital Recovery	0	50.0	2.1	7.9	0	9.7	19.6	22.2	2.7	9.1	19.1	11.4	2.5	45.5	1.5	.27
Capital Recovery	0	20-80	6.0	11.1	0	4.2	21.2	21.0	2.5	9.4	19.7	12.6	2.8	36.5	.5	.54
British	0	60.0	.1	6.0	0	11.0	17.1	23.8	3.0	9.0	17.1	12.7	2.8	56.5	31.7	.02
British	0	20-80	5.8	10.9	0	4.6	21.2	21.0	2.6	9.3	19.7	12.5	2.8	37.0	.6	.53

*All present values were taken at 12 percent discount rate, and mean prices of $11.00 per barrel of oil and $.60 per Mcf of associated gas were used in determining gross value of production.

adjustments to ATNPV among systems (to compensate for differences in risk).[40] Hence, it is only an approximate relative indicator of revenue differences. The second indicator, total expected production, measures differences in resource recovery which may be attributed to the lease system.[41]

The last three indicators measure the extent to which risk is shared by alternative systems relative to the current cash bonus system. If the chance of a less than normal profit is lower for an alternative system than for the current system, risk is considered to be lower, all other things being equal. The extent to which the expected bonus is altered by an alternative system is another indicator of risk sharing for given production considerations. This can be represented by the bonus ratio (the ratio of ATNPV for the test system to that of the cash bonus system).[42] However, for marginal production conditions, bonus changes are less important because the expected bonus is low. Thus, as a further indicator of risk sharing, the ratio of the mean ATNPV to the standard deviation of the ATNPV distribution was used. This indicator measures the relative spread of potential investment outcomes. Each of these indicators was devised in an attempt to measure the change in risk borne by private sector bidders under different leasing systems. Assuming risk aversion, these indicators would also be related to changes in the bonus payment and, hence, to the total economic rent collected by the government.

Before turning to a more comprehensive analysis, we will briefly review the results displayed in Table 28 using the criteria discussed above. In each of the marginal fields, the fixed royalty system reduced government revenue and ATNPV, increased the chance of a less than normal profit, reduced the mean/S.D. ratio, and reduced expected production. Hence, the only positive change for the fixed royalty system was the reduction in ATNPV; however, since ATNPV is already small on marginal fields, this is of little consequence. Based on the marginal fields analysis alone, one could conclude that there is no comparative advantage to the bonus system with a higher fixed royalty.

40

For the government revenue calculation, royalties, taxes paid and bonus payments were included. The bonus was arbitrarily set at seventy-five percent of the calculated after tax net present value for each system. Thus, a uniform risk discount was assumed across all test cases.

41

Note that this indicator differs from the mean discovery size value shown in another column of Table 28. That value refers to the average discovery when a reservoir is produced. That is, it is a condition expectation. Total expected production, on the other hand, is the unconditional expectation of production. That expectation accounts for dry hole risk and economic variables; thus, considering all Monte Carlo iteration results.

42

Actual tests of risk sharing using the ATNPV indicator, however, directly measured statistically significant differences between ATNPV values.

For the variable royalty systems, such a clear cut conclusion can not be drawn. In fact, when the royalty is variable with production, the direction of change is not consistent for any of the five criteria used. When the royalty rate is variable with value, the direction of change is not consistent for three of the five variables. However, two of the risk related variables consistently compare favorably with the current cash bonus system: chance of a less than normal profit and the mean/S.D. ATNPV ratio. To completely evaluate these systems, tests on more profitable fields will be needed.

The IRS base fixed rate profit share system was consistently inferior (except for the bonus ratio) to the current cash bonus system on all marginal fields. The variable rate system was inferior on two field sizes and better on the third by all five criteria. From the marginal field data, the fixed rate IRS base profit share system is clearly no better than the current system. The variable rate system also appears to be no better but will receive closer scrutiny in the tests on more profitable fields.

The fixed rate capital recovery systems (annuity capital recovery and British type) tended to increase government revenue, reduce the bonus payment, and reduce the mean/S.D. ratio (an increase in risk). The annuity capital recovery system tended to reduce the chance of a less than normal profit while the British type system tended to increase it. Similarly, the annuity capital recovery system tended to increase the expected amount of production while the British type plan tended to reduce it. The latter results are probably due to the particular rate which was used for the British system. Since rates were evaluated only in ten percent intervals, the rate used for the British system appears to be much closer to the actual minimum than the rate selected for the annuity capital recovery. For instance, the actual minimum rate for the British plan could be sixty-two percent whereas it might be fifty-eight percent for the capital recovery system. This explanation accounts for the increase in chance of a less than normal profit, and, consequently, the reduced production under the British system. Both systems merit further examination on more profitable areas.

The variable rate capital recovery profit share systems consistently led to a reduction in the chance of a less than normal profit, increased bonus payments, reduced mean/S.D. ratios, and increased production. Government revenue was reduced in both cases on the large high cost field and increased in the other two production situations. Since the bonus increase is not a problem in marginal producing areas, these systems appear to offer the most significant improvement over the current system in marginal producing areas. We now turn to the analysis of more profitable areas to determine the extent to which these preliminary conclusions are valid in a broader context.

Test Results on Non-marginal Areas: Table 29 displays the analytical results derived from applying the alternative systems to a medium and large field discovery in cost region 1 (Province 8). Contingency rates from the previous tests on marginal reservoirs (Table 28) were used.[43] Also, similar price

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[43] This insures that the discovery of a marginal field will not result in

Table 29.--Results of Leasing Model Simulations Using Economically Non-marginal Petroleum Fields in a Representative Production Cost Area*

Alternative Leasing System	Contingency Rates		Economic Impacts					Physical Factors			Evaluation Criteria					
	Royalty Rate (%)	Profit Share Rate (%)	ATNPV (P.V.-mil. $)	Tax (P.V.-mil. $)	Royalty (P.V.-mil. $)	Profit Share (P.V.-mil. $)	Total Econ. Rent (P.V.-mil. $)	Mean Disc. Size (mil. bbls.)	Instld. Cap. (mil. bbls.)	Prod. Time Horizon (years)	Govt. Rev. (bonus=.75x ATNPV)	Expec. Oil Prod.	Expec. Nat. Gas Prod.	Chance of Less than Normal Profit(%)	Bonus Ratio	Mean ATNPV / S.D. ATNPV
Medium Reservoir Discovery in Cost Region 1 (Province 8)																
Current Cash Bonus	16.7	0	76.5	66.1	41.1	0	183.4	76.5	9.5	9.0	164.5	63.9	14.1	12.5	1.0	1.10
Royalty - Fixed	20.0	0	71.3	62.5	49.0	0	182.8	77.4	9.6	9.0	165.0	63.6	14.0	13.0	1.1	1.07
Royalty - Variable with Production	15-40	0	73.0	63.0	47.5	0	183.6	76.3	9.4	9.0	165.3	64.1	14.1	11.0	1.1	1.21
Royalty - Variable with Value	5-50	0	64.8	55.7	53.6	0	174.2	74.6	8.2	10.3	158.0	65.2	14.3	8.0	1.2	1.54
Profit Share																
IRS Base	0	30.0	64.3	57.3	0	62.0	183.6	76.5	9.5	9.0	167.5	63.9	14.1	11.5	1.2	1.10
IRS Base	0	20-80	64.7	56.5	0	61.3	182.4	75.1	9.1	9.1	166.3	64.6	14.2	9.0	1.2	1.38
Capital Recovery	0	50.0	53.8	49.3	0	82.4	185.5	74.2	9.2	9.0	172.0	64.8	14.3	7.5	1.4	1.25
Capital Recovery	0	20-80	74.2	63.3	0	47.0	184.4	74.6	9.2	9.0	165.8	64.8	14.3	8.0	1.0	1.43
British	0	60.0	45.0	42.8	0	97.2	185.0	74.9	9.3	9.0	173.8	64.6	14.2	8.5	1.7	1.24
British	0	20-80	72.9	62.3	0	49.0	184.1	74.6	9.2	9.0	165.9	64.8	14.3	8.0	1.1	1.44
Large Reservoir Discovery in Cost Region 1 (Province 8)																
Current Cash Bonus	16.7	0	350.3	265.4	147.0	0	762.7	281.2	34.9	9.0	675.1	229.6	50.5	13.5	1.0	.94
Royalty - Fixed	20.0	0	333.3	253.0	176.4	0	762.7	281.2	34.9	9.0	679.4	229.6	50.5	13.5	1.1	.94
Royalty - Variable with Production	15-40	0	278.3	207.7	279.8	0	765.8	273.8	33.8	9.1	696.2	231.4	50.9	10.5	1.3	1.11
Royalty - Variable with Value	5-40	0	205.5	162.0	377.5	0	745.0	261.8	30.2	11.3	693.6	234.6	51.6	5.5	1.7	1.07
Profit Share -																
IRS Base	0	30.0	309.2	233.2	0	225.1	767.5	273.8	34.0	9.0	690.2	231.3	50.9	10.5	1.1	.99
IRS Base	0	20-80	198.4	143.5	0	333.6	675.5	267.9	27.0	12.3	625.9	235.2	51.8	8.0	1.8	1.92
Capital Recovery	0	50.0	242.1	182.2	0	346.7	771.0	267.9	33.3	9.0	710.5	232.6	51.1	8.0	1.5	1.07
Capital Recovery	0	20-80	223.1	159.9	0	312.2	695.2	267.9	28.3	11.4	639.4	234.7	51.6	8.0	1.6	1.90
British	0	60.0	205.3	154.8	0	410.8	770.9	267.9	33.3	9.0	719.6	232.6	51.1	8.0	1.7	1.11
British	0	20-80	218.4	156.8	0	327.0	702.2	266.7	28.5	11.3	647.6	234.7	51.6	7.5	1.6	1.89

*All present values were taken at 12 percent discount rate, and mean prices of $11.00 per barrel of oil and $.60 per Mcf of associated gas were used in determining gross values of production.

expectations were assumed. Several patterns emerge from a cursory review of these results. The fixed rate annuity and British type capital recovery systems clearly resulted in higher government revenue than the current cash bonus system. The chance of a less than normal profit was reduced most by the variable royalty rate system with the rate based on value of production. However, all the capital recovery profit share systems also yielded a significant improvement (reduction) in this indicator. Significant bonus reduction on the large field was achieved by all capital recovery profit share systems, and by the variable rate IRS based profit share and variable rate (value) royalty systems. On the medium size field, the greatest bonus reduction was achieved by the fixed rate capital recovery systems. The greatest improvement in the mean/S.D. ratio (increase) was achieved by the variable rate systems (both royalty and profit share). The variable rate systems tended to narrow the range of expected outcomes as would be expected. None of the alternative systems produced a major change in the expected amount of production.

Statistical Decision Criteria: Having reviewed simulation results for both marginal and more profitable production situations, we will combine the results to determine what conclusions can be reached concerning the overall effectiveness of alternative systems. Table 30 displays the percentage changes (relative to the current cash bonus system) in four of the indicator variables described above: government revenue, chance of a less than normal profit, mean/S.D. ratio, and expected oil production. The actual value of the fifth variable, bonus ratio, is also included in the table. After reviewing the changes resulting from each system, each system indicator was classified on the basis of whether or not statistically <u>significant</u> differences exist between that system and the current cash bonus system. For three of the indicators - bonus ratio, chance of a less than normal profit, and expected oil production - we were able to establish valid statistical tests of significance.

Using the three indicator distributions, we tested the null hypothesis that the means were not significantly different, as shown in equation 40:

$$H_o: \ u_1 - u_2 = 0 \tag{40}$$

where u_1 and u_2 are the indicator population means for the cash bonus and alternative system, respectively. In the first test, to determine if ATNPV values are significantly different, we use the distributions of the difference of the ATNPV means ($\theta = A_1 - A_2$). For large samples, the distribution of θ is approximately normal even though the ATNPV sample distributions are not normal. The variable θ is normally distributed with mean $u_1 - u_2$ and standard deviation (σ_θ) as shown in equation 41:

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a failure to develop. That is, the contingency rates were not set at a higher level than that required for development of the marginal reservoir in the highest cost region.

Table 30.--Percentage Change in Leasing System Evaluation Criteria (Compared to the Current Cash Bonus System) for Representative Reservoir Sizes and Cost Regions*

System	Government Revenue	Chance of Less than Normal Profit	Bonus Ratio	Variance Reduction	Expected Oil Production
Cost Region 1 -- Small Reservoir					
Royalty - Fixed	-.04	-.09	1.5	-.26	-.06
Royalty - Variable	+.02	+.04	.9	+.13	+.04
Royalty - Variable with Value	+.09	+.24	.5	+.77	+.15
Profit Share					
IRS - Fixed	-.10	-.20	4.0	-.68	-.12
IRS - Variable	+.02	+.03	1.1	+.03	+.03
Capital Recovery - Fixed	+.07	+.06	1.5	-.13	+.05
Capital Recovery - Variable	+.11	+.25	.5	+.74	+.15
British - Fixed	-.04	-.16	31.7	-.94	+.17
British - Variable	+.11	+.24	.6	+.71	+.15
Cost Region 1 -- Medium Reservoir					
Royalty - Fixed	0	-.04	1.1	-.03	0
Royalty - Variable	0	+.12	1.1	+.10	0
Royalty - Variable with Value	-.04	+.36	1.2	+.40	+.02
Profit Share					
IRS - Fixed	+.02	0	1.2	0	0
IRS - Variable	+.01	+.28	1.2	+.25	+.01
Capital Recovery - Fixed	+.05	+.40	1.4	+.14	+.01
Capital Recovery - Variable	+.01	+.36	1.0	+.30	+.01
British - Fixed	+.06	+.32	1.7	+.13	+.01
British - Variable	+.01	+.36	1.1	+.31	+.01
Cost Region 1 -- Large Reservoir					
Royalty - Fixed	+.01	0	1.1	0	0
Royalty - Variable	+.03	+.22	1.3	+ .18	+.01
Royalty - Variable with Value	+.03	+.59	1.7	+ .14	+.02
Profit Share					
IRS - Fixed	+.02	+.22	1.1	+ .05	+.01
IRS - Variable	-.07	+.41	1.8	+1.04	+.02
Capital Recovery - Fixed	+.05	+.41	1.5	+ .14	+.01
Capital Recovery - Variable	-.05	+.41	1.6	+1.02	+.02
British - Fixed	+ 07	+.41	1.7	+ .18	+.01
British - Variable	-.04	+.44	1.6	+1.01	+.02

Table 30.--Continued

System	Government Revenue	Chance of Less than Normal Profit	Bonus Ratio	Variance Reduction	Expected Oil Production
Cost Region 3 -- Medium Reservoir					
Royalty - Fixed	-.02	-.01	1.6	-.29	-.02
Royalty - Variable	-.02	+.01	1.1	0	+.03
Royalty - Variable with Value	-.10	+.05	1.6	0	+.10
Profit Share					
IRS - Fixed	-.04	-.03	3.6	-.65	-.06
IRS - Variable	-.08	-.01	2.1	-.29	-.01
Capital Recovery - Fixed	+.07	+.02	1.6	-.18	+.03
Capital Recovery - Variable	+.10	+.08	.6	+.71	+.12
British - Fixed	+.05	0	3.1	-.53	-.01
British - Variable	+.09	+.07	.6	+.65	+.11
Cost Region 5 -- Large Reservoir					
Royalty - Fixed	-.04	-.04	1.5	-.29	-.07
Royalty - Variable	-.13	-.03	12.0	-.86	-.04
Royalty - Variable with Value	+.10	+.09	.6	+.64	+.14
Profit Share					
IRS - Fixed	-.07	-.06	3.1	-.64	-.11
IRS - Variable		No Development			
Capital Recovery - Fixed	+.08	+.03	2.1	-.36	+.05
Capital Recovery - Variable	-.01	+.06	.9	+.43	+.09
British - Fixed	+.01	-.03	11.4	-.86	-.07
British - Variable	-.02	+.09	1.5	+.07	+.14

*The bonus ratio is displayed as an actual value, not a percentage.

(41) $$\sigma_\theta = \sqrt{\frac{\sigma_1^{\,2}}{n_1} + \frac{\sigma_2^{\,2}}{n_2}}$$

Because the sample size is equal for all ATNPV sample distributions and the sample variance can be used as an estimate of the population variance, the sample standard deviation (S_θ) is given by equation 42:

(42) $$S_\theta = \sqrt{\frac{S_1^{\,2} + S_2^{\,2}}{n}}$$

To conduct the test, we must find the value of θ such that the probability is equal to α that θ will be larger. For a one-tail test with $\alpha = .1$, this value is given by equation 43:

(43) $$\theta_\alpha = 1.28\sigma_\theta \cong 1.28S_\theta$$

Use of a lower value for α leads to increasing the probability of a Type II error (accepting H_o when H_o is false) and decreasing the power of the test (Merrill and Fox, pp. 294-296).

This procedure was used to determine statistically significant differences in values for three of the five indicators. The test could not be used for the government revenue or mean/S.D. indicators because the variance for these distributions was not available. However, by observing the magnitude of changes which were required for statistical significance in the other three indicators, we could set a standard which would approximate a test of significance. For government revenue, we used a change of ten percent on the three marginal fields and five percent on the two more profitable fields as the minimum changes for a significant difference. A twenty-five percent or greater change in the mean/S.D. indicator was used.

Table 31 shows the signficant changes for all fields using plus and minus signs to indicate the direction of change. Table 32 provides a summary of these results using four different weighting schemes to aggregate the results shown in Table 31. Each plus or minus value in Table 31 was set equal to 1 or -1 for purposes of this summary ranking. In addition, Table 32 displays, for each leasing system, a summary total of weighting results. The first sum assumes equal weighting for all indicators for all fields. Using this criterion, the three variable rate systems are clearly superior to the others. The fixed rate capital recovery profit share systems also appear significantly better than the cash bonus system. The second summation includes the more profitable fields only. The results indicate that all the profit share systems with the exception of the fixed rate IRS system and the variable rate royalty (based on value) system perform significantly better than the current cash bonus system. The third sum includes government revenue changes only and indicates that only the fixed rate capital recovery profit share systems perform better than the current cash bonus system. The fourth sum eliminates changes in the mean/S.D. indicator because there is less certainty of statistical validity in that variable than in the others. These results indicate that all the capital recovery profit

Table 31.--Statistically Significant Changes in Leasing Systems (Compared to the Current Cash Bonus System) as Indicated by Evaluation Criteria for Representative Reservoir Sizes and Cost Regions

System	Government Revenue	Chance of Less than Normal Profit	Bonus Ratio	Variance Reduction	Expected Oil Production
Cost Region 1 -- Small Reservoir					
Royalty - Fixed				-	
Royalty - Variable					
Royalty - Variable with Value		+	-	+	+
Profit Share					
IRS - Fixed		-	+	-	
IRS - Variable					
Capital Recovery - Fixed					
Capital Recovery - Variable	+	+	-	+	+
British - Fixed		-	+	-	+
British - Variable	+	+		+	+
Cost Region 1 -- Medium Reservoir					
Royalty - Fixed					
Royalty - Variable					
Royalty - Variable with Value		+	+	+	
Profit Share					
IRS - Fixed			+		
IRS - Variable			+	+	
Capital Recovery - Fixed	+	+	+		
Capital Recovery - Variable		+		+	
British - Fixed	+	+	+		
British - Variable		+		+	
Cost Region 1 -- Large Reservoir					
Royalty - Fixed					
Royalty - Variable			+		
Royalty - Variable with Value		+	+		
Profit Share					
IRS - Fixed					
IRS - Variable	-	+	+	+	
Capital Recovery - Fixed	+	+	+		
Capital Recovery - Variable	-	+	+	+	
British - Fixed	+	+	+		
British - Variable		+	+	+	

Table 31.--Continued

System	Government Revenue	Chance of Less than Normal Profit	Bonus Ratio	Variance Reduction	Expected Production
Cost Region 3 -- Medium Reservoir					
Royalty - Fixed				-	
Royalty - Variable					
Royalty - Variable with Value	-				
Profit Share					
IRS - Fixed			+	-	
IRS - Variable				-	
Capital Recovery - Fixed					
Capital Recovery - Variable	+	+		+	
British - Fixed			+	-	
British - Variable				+	
Cost Region 5 -- Large Reservoir					
Royalty - Fixed				-	
Royalty - Variable	-		+	-	
Royalty - Variable with Value	+	+		+	
Profit Share					
IRS - Fixed				-	
IRS - Variable					
Capital Recovery - Fixed				-	
Capital Recovery - Variable				+	
British - Fixed			+	-	
British - Variable		+			

Table 32.--Leasing System Evaluation Summary

Alternative Leasing System	Equal Weight Ranking	Non-marginal Fields	Government Revenue	Less Mean/S.D. Criteria	Total
Royalty - Fixed	- 3	0	0	0	- 3
Royalty - Variable	0	+ 1	- 1	+ 1	+ 1
Royalty - Variable with Value	+ 9	+ 5	0	+ 6	+20
Profit Share					
IRS - Fixed	- 1	+ 1	0	+ 2	+ 2
IRS - Variable	+ 3	+ 4	- 1	+ 1	+ 7
Capital Recovery - Fixed	+ 5	+ 6	+ 2	+ 6	+19
Capital Recovery - Variable	+11	+ 4	+ 1	+ 6	+22
British - Fixed	+ 6	+ 6	+ 2	+ 9	+23
British - Variable	+11	+ 5	+ 1	+ 7	+24

share systems and the variable rate royalty (value) system are significantly better than the current cash bonus system.

The equally weighted sum of each of these rankings indicates that the four capital recovery profit share systems (annuity and British -- fixed and variable rate) and the variable rate royalty system based on value all are significantly better than the current cash bonus system. The fixed rate royalty and IRS profit share systems appear no better than the current cash bonus system. The quantitative indications of change shown in Table 30 also support these general conclusions. Within the group of superior systems, results are not sufficiently different to make any overall judgements. However, it appears that each of these systems are preferable leasing options (to the current cash bonus system) based on the evaluation criteria used in this analysis. Experimentation with these systems is clearly needed. Actual experience with the systems would aid in making judgements regarding trade-offs in achieving competing objectives and differences in administrative costs. Experimentation with profit share systems requires new legislation (now pending before Congress). However, the variable rate royalty system can be implemented under existing statutory authority.

Conclusion: The analysis of alternative leasing systems has been presented in this part of Chapter VI. The conclusion is that any of five new leasing systems could provide significant improvements over the current system. This conclusion will form the basis for the comparative analysis of leasing schedules in Part II of this Chapter.

Part II

Alternative Leasing Schedules

In this section we will utilize the results of the leasing system analysis in comparing alternative leasing schedules. Reserve data for the entire OCS developed in Chapter II and cost data developed in Chapter V will be used as inputs to the analytical model (Chapter IV) to compare the economic and production impacts. Four different schedule approaches and two schedule lengths (eight actual schedules) will be analyzed. The results will demonstrate the impact of both the leasing schedule and the leasing system on economic rent, total production, and production profiles.

Background Data and Analysis: The analysis in part one of this chapter concluded that any of five leasing systems appear superior to the current cash bonus system. Furthermore, differences among these five systems were insufficient to make an obvious selection among them. Because it would be prohibitively expensive to evaluate each combination of these leasing systems and alternative leasing schedules, we decided to select one of the five systems for this analysis. That system, the annuity capital recovery system with a fixed rate profit share of fifty percent, was then compared to results using the current cash bonus approach.

Input data on assumed field size distributions and the expected number of fields for each OCS subregion were developed in Chapter II and displayed in Table 8, page 37. Investment and operating cost data were developed in Chapter V. The entire OCS area was divided into five cost regions as shown in Table 12, page 84. Tables 24 and 25, on pages 91-92, summarize the cost inputs used in the analysis. Table 26, on pages 96-97, lists other inputs which were used in all OCS subregions. To test sensitivity of the results to expected prices, the three sets of initial prices used in the evaluation of leasing systems (Part I of this chapter) were also used here.

The results of the simulations for each OCS subregion and field size using the current cash bonus and annuity capital recovery leasing systems with the three stipulated price assumptions are tabulated in Appendix B. Each table lists the mean present values of ATNPV, income taxes, royalty or profit share collections, and economic rent; production cost; percent chance of a less than normal profit; reserve discovery size; installed production capacity; production time horizon; and expected oil and natural gas production. Tables B-1 through B-6 display results for the three price expectations using the current cash bonus system, and Tables B-7 through B-12 display the same results for the annuity capital recovery system. The data in these Tables form the basis for the subsequent analysis of alternative leasing schedules.

Methodology For Developing Leasing Schedules: For purposes of analysis, four schedules were designed to illustrate the production and economic effects of different scheduling objectives. The four schedules include:

- Uniform
- Maximum economic rent
- Maximum production (in present barrel equivalents)
- Maximum environmental preservation

The rationale and lease sequence for each of these schedules is developed below.

Schedule Length: For each of the four scheduling objectives, two different lengths were selected for analysis: ten years and twenty years. These two planning horizons were selected to demonstrate the effect of leasing rates on production profiles through time and the time distribution of economic rent. The authors recognize that it is unlikely that seventy-five percent of the remaining OCS reserves would be leased in ten years (see Chapter II); nonetheless, the ten year leasing period was chosen to illustrate the maximum impact of an accelerated leasing program.

For all alternative schedules, the same total resource estimates were used in order to maintain comparability. In the descriptions of alternative schedules which follow, only the ten year schedules are actually displayed. In each case, the twenty year schedule is simply a lengthened version of the ten year schedule with no basic changes in structure. In this way, the isolated contrast needed for comparison of schedule lengths can be obtained.

Acreage Limitations on Leasing Schedules: The areas of the OCS included in the USGS-RAG energy resource estimates in Circular 725 total 673,291 square miles or 430,900,000 acres, if the four geological provinces with estimates of negligible resources (see Table 1) are excluded. These numbers are drawn from the Basic Files for Circular 725 (USGS, Denver) and are shown in Table 33. If one assumes that each of the hypothetical 574 oil and natural gas fields which represent seventy-five percent of the expected total offshore recoverable reserves (listed in Table 12) will be discovered by leasing and exploration of ten offshore tracts (5760 acres x 10), then 33,062,400 acres would have to be leased and explored to discover all 574 fields (574 x 5760 x 10). Using 33,062,400 acres as a point of departure, we assume that approximately 3.3 million acres would be leased in each year of a ten year lease program.

The next step is to make an assessment of the acreage which corresponds to a single exploration effort unit for each individual subregion (see Chapter II, Table 9; and Appendix A). Using reasoning similar to that above, the number of fields expected to be discovered in each subregion was multiplied by 5760 acres and by ten tracts. In this way, a rough approximation of acreage required to be leased in each subregion is obtained. The total and exploration effort unit acreage value for each subregion are shown in Table 33.

Applying the 3.3 million acres per year constraint to the formulation of the leasing schedule implies, for example, that no more than three exploration effort units from the Central and Western Gulf Subregion could be compressed into any one year of the leasing schedule, while, on the other hand, all ten of the exploration effort units from the Gulf of Alaska potentially could be included in one year of the schedule. However, because it seems unreasonable to expect that an entire subregion such as the Gulf of Alaska would be leased in only one year, a limit of five exploration effort units per year for each subregion was imposed in formulating the schedules.

It is recognized that these acreage estimates are highly conjectural. However, large errors in the estimates would not significantly affect the analytical results because the acreage figures are only used as a constraint and in no other way affect the time streams of economic rent or production.

Uniform Leasing Schedule: This schedule entails leasing one effort unit of each OCS subregion per year in a ten year schedule and .5 effort units per

Table 33.--OCS Acreage Considerations for Each of the Thirteen Subregions

Subregion	Number of Fields	Total Acreage Assumed Leased in Each Subregion	Total Acreage Per Exploration Effort Unit	Total Acres in Subregion
1. Arctic Ocean	101	5,818,000	581,800	53,820,160
2. Central Chukchi	88	5,069,000	506,900	24,512,000
3. Bering Sea	117	6,739,000	673,900	144,854,400
4. Gulf of Alaska	5	288,000	28,800	42,807,680
5. Cook Inlet	27	1,555,000	155,500	8,090,240
6. North Pacific	3	172,800	17,280	22,542,720
7. Santa Cruz	7	403,200	40,320	2,546,560
8. S. California	12	691,200	69,120	17,851,520
9. Central and Western Gulf	182	10,483,000	1,048,300	41,623,680
10. MAFLA	5	288,000	28,800	15,330,560
11. North Atlantic	7	403,200	40,320	23,505,920
12. Central Atlantic	12	691,200	69,120	11,118,720
13. South Atlantic	8	460,800	46,080	22,302,080
	574			

year in a twenty year schedule. In other words, the ten effort units for each subregion (displayed in Appendix A) are spread uniformly over the leasing planning horizon. This schedule serves as a basis of comparison for the other schedules.

Maximum Economic Rent Schedule: An attempt to maximize the economic rent (present value) resulting from offshore leasing entails maximizing the present value of total economic rent determined from the simulation model. The expected economic rent for each subregion is obtained by multiplying the economic rent for each developed field size (Tables B-1 to B-12, Appendix B) by the number of fields of each size and summing. Table 34 provides a compilation of the expected economic rent by subregion plus the order of leasing if regions are leased according to their contribution (using oil and natural gas prices of \$13.00 and \$1.50 respectively).[44]

In order to maximize economic rent, it follows from Table 34 that the Central and Western Gulf and Southern California are most favorable areas for early emphasis in such a leasing schedule. Both the total economic rent for these subregions and the total rent for the large field sizes within them dictate that rapid leasing of the first half of the exploration effort units, where most of the large fields are concentrated, would assist in meeting the objective.[45] When the objective of the leasing program is to maximize the contribution to economic rent, these economic considerations and the acreage constraints discussed above permit ex ante derivation of an appropriate schedule. Table 35 displays the results of this derivation.

Maximum Production Schedule: Table 36 displays the total production expected from each developable field size for each subregion and the total expected production at expected prices of \$13.00 per barrel of oil and \$1.50 per Mcf of natural gas (when using the current cash bonus bidding system). In order to maximize the present barrel equivalent of production, a leasing schedule which accelerates the leasing of large fields, while delaying the leasing of small

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It is probable that a greater contribution might be achieved by attempting to lease the most favorable prospects first regardless of the region of occurence. This process, however, is beyond both the scope of the current analysis and the ability of the government to structure an appropriate leasing schedule in the face of uncertainty over field discovery size. Moreover, the main thrust here is to demonstrate the direction of changes in regional development patterns under alternative schedules. In addition, indications of the changes in production profiles and present value of economic rent can be obtained.

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Analysis of the exploration effort schedules in Appendix A for all of the geologic subregions indicates that, on average, sixty-nine percent of the large fields are contained in the first five exploration effort units. Because a substantial portion of the total economic rent is provided by the large fields, an emphasis on leasing the first five exploration effort units of these subregions with relatively high total economic rent would assist in maximizing the present value of rents generated.

Table 34.--Economic Rent for the $13.00 per Barrel of Oil and $1.50 per Mcf of Natural Gas Cash Bonus System

Subregion	Field Size Category	Number of Fields	Economic Rent for Each Field (P.V.-mil. $)	Total Economic Rent for Each Field Size (P.V.-mil. $)	Total Economic Rent for Each Subregion (P.V.-mil. $)	Leasing Order to Maximize Economic Rent
1. Arctic Ocean	3	18	173.66	3125.88	3348.08	5
	2	22	10.10	222.20		
2. Central Chukchi	3	17	147.78	2512.26	2648.60	6
	2	17	8.02	136.34		
3. Bering Sea	3	14	107.38	1503.32	2101.84	8
	2	26	23.02	598.52		
4. Gulf of Alaska	3	3	1120.10	3360.30		
	2	0	74.07	0.00	3360.30	4
	1	0	-4.70	0.00		
5. Cook Inlet	3	3	388.74	1166.22		
	2	4	134.16	536.64	1702.86	10
	1	14	-7.11	-99.54		
6. North Pacific	3	1	722.60	722.60		
	2	1	63.67	63.67	786.27	12
	1	0	8.34	8.34		
7. Santa Cruz	3	1	195.14	195.14		
	2	1	76.25	76.25	296.20	13
	1	3	8.27	24.81		
8. S. California	3	7	938.90	6572.30		
	2	2	232.94	465.88	7070.38	2
	1	1	32.20	.20		
9. Central and Western Gulf	3	6	824.10	4944.60		
	2	10	348.77	3487.70	9629.10	1
	1	34	35.20	1196.80		

Table 34.--Continued

Subregion	Field Size Category	Number of Fields	Economic Rent for Each Field (P.V.-mil. $)	Total Economic Rent for Each Field Size (P.V.-mil. $)	Total Economic Rent for Each Subregion (P.V.-mil. $)	Leasing Order to Maximize Economic Rent
10. MAFLA	3	3	721.00	2164.80		
	2	1	144.84	144.84	2309.64	7
	1	0	8.98	0.00		
11. North Atlantic	3	3	588.89	1766.67		
	2	1	74.84	74.84	1841.51	9
	1	0	-6.83	0.00		
12. Central Atlantic	3	5	720.00	3600.00		
	2	2	117.86	235.72	3835.72	3
	1	2	-2.13	0.00		
13. South Atlantic	3	3	290.36	871.08		
	2	1	82.08	82.08	955.69	11
	1	1	2.53	2.53		

Table 35.--Schedule to Maximize Economic Rent - Ten Years
(effort units per year)

Subregion	Year									
	1	2	3	4	5	6	7	8	9	10
9. Central and Western Gulf	3	2	1	1	1	1	1			
8. S. California	3	2	1	1	1	1	1			
12. Central Atlantic		4	1	1	1	1	1	1		
4. Gulf of Alaska		4	1	1	1	1	1	1		
1. Arctic Ocean		1	3	1	1	1	1	1	1	
2. Central Chukchi				3	2	1	1	1	1	1
10. MAFLA					2	2	1	2	2	1
11. North Atlantic								4	3	3
5. Cook Inlet								3	3	4
13. South Atlantic							1	2	3	4
6. North Pacific							1	2	3	4
7. Santa Cruz							1	2	3	4

Table 36.--Oil Production By Field Size and Subregion*

Subregion	Field Size Category	Total Production From Individual Developable Fields (mil. bbls.)	x	Number of Fields	=	Total Production for Each Field Size (mil. bbls.)	Total Production for Subregion (mil. bbls.)	Optimum Order to Maximize Production
1. Arctic Ocean	3	71.30		18		1283.36	1629.73	3
	2	15.74		22		346.37		
2. Central Chukchi	3	64.17		17		1090.89	1345.02	4
	2	14.95		17		254.13		
3. Bering Sea	3	40.25		14		563.50	978.01	5
	2	15.94		26		414.51		
4. Gulf of Alaska	3	278.93		3		836.78	836.78	7
	2	28.41		0		0.00		
	1	1.78		0		0.00		
5. Cook Inlet	3	119.53		3		358.59	590.90	8
	2	54.98		4		219.94		
	1	.88		14		12.37		
6. North Pacific	3	176.56		1		176.56	198.16	12
	2	1.60		1		21.60		
	1	1.65		0		0.00		
7. Santa Cruz	3	40.23		1		40.23	71.37	13
	2	26.23		1		26.23		
	1	1.64		3		4.92		
8. S. California	3	228.81		7		1601.67	1742.62	2
	2	63.81		2		127.63		

Table 36.--Continued

Subregion	Field Size Category	Total Production From Individual Developable Fields (mil. bbls.)	x	Number of Fields	=	Total Production for Each Field Size (mil. bbls.)	Total Production for Subregion (mil. bbls.)	Optimum Order to Maximize Production
9. Central and Western Gulf	3	141.05		6		846.30	1817.84	1
	2	63.81		10		638.07		
	1	9.81		34		333.47		
10. MAFLA	3	172.69		3		518.08	557.93	9
	2	39.85		1		39.85		
	1	5.43		0		0.00		
11. North Atlantic	3	147.10		3		441.29	468.39	10
	2	27.09		1		27.09		
	1	.72		0		0.00		
12. Central Atlantic	3	175.22		5		876.12	953.36	6
	2	36.53		2		73.07		
	1	2.09		2		4.17		
13. South Atlantic	3	70.52		3		211.55	236.97	11
	2	22.55		1		22.55		
	1	2.88		1		2.88		

*Using the current cash bonus leasing system and prices of $13.00 per barrel for oil and $1.50 per Mcf for natural gas.

fields and subregions, would seem preferable.[46] Previously, it was assumed that attempting to accelerate leasing of large fields could be accomplished by placing early scheduling emphasis on the first five exploration effort units in each subregion. Coupling these considerations with the leasing constraints on yearly acreage, a schedule which attempts to maximize the present barrel equivalent of production is displayed in Table 37.

Table 37.--Schedule to Maximize Production - Ten Years
(effort units per year)

Subregion	Year									
	1	2	3	4	5	6	7	8	9	10
9. Central and Western Gulf	3	2	1	1	1	1	1			
8. S. California	3	2	1	1	1	1	1			
1. Arctic Ocean		2	3	1	1	1	1	1		
2. Central Chukchi			1	3	1	1	1	1	1	1
3. Bering Sea					2	2	2	2	1	1
12. Central Atlantic								4	3	3
4. Gulf of Alaska								4	3	3
5. Cook Inlet								3	4	3
10. MAFLA								2	4	4
11. North Atlantic									5	5
13. South Atlantic									5	5
6. North Pacific									5	5
7. Santa Cruz									5	5

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46 Because each of the hypothetical leasing schedules includes the same total reserve estimates, the absolute value of expected total production is the same for all schedules. The max production schedule attempts to maximize the present barrel equivalents of production, which is analogous to economic present value.

Maximum Environmental Protection Schedule: There are at least two potential approaches to formulating a schedule which maximizes environmental protection. First, it might be desirable to account for environmental withdrawals in each subregion. That is, portions of the acreage nominated by exploration companies is withdrawn from leasing because of environmental considerations. To the extent that the nomination process reflects ex ante beliefs about petroleum prospects and these beliefs are correlated with actual discovery (which we assume in this analysis), environmental withdrawals in the early years of a leasing program could lead to postponement or elimination of significant petroleum resource production. Thus, a leasing schedule might be formulated such that a certain portion of the fields projected to be discovered in the early exploration effort units would either be delayed or excluded completely from the leasing process. However, no reasonable basis could be found for devising such a schedule because of the paucity of subregional environmental data.

Alternatively, it may be possible to formulate an environmental preservation schedule by ordering the leasing sequence of subregions according to potential environmental damage criteria. One such case is discussed in the Final Environmental Statement: Proposed Increase in Oil and Gas Leasing on the Outer Continental Shelf (Bureau of Land Management, 1975, pp. 341-347). If leasing of environmentally hazardous areas is deferred until later in the lease schedule, one would hope that 1) technology would be developed in the interim which would be better suited to cope with environmental problems, or 2) that other sources of energy would become available which would alleviate the necessity for development of the energy resources in these environmentally hazardous regions. The Final Environmental Statement proposes two alternative sequences based on this principle of saving the worst areas for last (Table 137, p. 343). One of the sequences, "Schedule B," is listed in Table 38.

Table 38.--Region Leasing Sequence for Environmental Preservation

Earliest	I.	Gulf of Mexico, Northern Pacific Coast
	II.	South Atlantic
	III.	North and Mid-Atlantic, S. California, Cook Inlet
Latest	IV.	All Alaska areas except Cook Inlet

This proposed sequence is subjective and is "not derived from precise scientific methodology" (BLM, 1975, p. 344).

To implement an environmental concerns schedule based on the above sequence, the effort units for each subregion are scheduled according to the environmental preservation sequence found in Table 38. The environmental preservation schedule is displayed in Table 39.

Table 39.--"Save the Worst for Last" Environmental Schedule - Ten Years (effort units per year)

Subregion	Year									
	1	2	3	4	5	6	7	8	9	10
9. Central and Western Gulf	3	3	3	1						
6. North Pacific	4	3	3							
10. MAFLA	4	3	3							
13. South Atlantic			2	4	3	1				
7. Santa Cruz			4	3	3					
11. North Atlantic			4	4	2					
12. Central Atlantic				4	4	2				
8. S. California				4	4	2				
5. Cook Inlet				4	4	2				
3. Bering Sea					1	2	2	2	2	1
2. Central Chukchi					1	1	2	2	2	2
4. Gulf of Alaska					3	2	2	2	1	
1. Arctic Ocean						1	2	2	2	3

Schedule Comparison -- Economic Rent: The first basis for comparing the alternative leasing schedules is in terms of the present value of economic rent. Economic rent is the sum of ATNPV, taxes, and royalty or profit share payments. Table 40 gives the total and discounted economic rent for each of the schedules and time periods discussed above. Several points emerge from the data presented.

1. As would be expected, total economic rent varies significantly with the price levels of oil and natural gas.

2. The present value of expected economic rent falls by about twenty-five percent from the ten year to the twenty year schedules.

Table 40.--Leasing Schedule Comparisons Based Upon Economic Rent*

Leasing System	Prices: Oil ($ per bbl.)	Prices: Gas ($ per Mcf)	Total Economic Rent (billion dollars)	Discounted Economic Rent (Billion $): Ten Year Schedule: Uniform	Ten Year Schedule: Max Econ. Rent	Ten Year Schedule: Max Prod.	Ten Year Schedule: Environment	Twenty Year Schedule: Uniform	Twenty Year Schedule: Max Econ. Rent	Twenty Year Schedule: Max Prod.	Twenty Year Schedule: Environment
Cash Bonus	11.00	.60	32.97	23.42	24.42	21.92	24.27	17.32	18.70	16.03	18.40
Cash Bonus	13.00	1.50	55.93	40.14	41.64	38.06	41.30	29.85	32.01	28.23	31.48
Cash Bonus	16.00	2.00	80.42	57.36	59.20	54.58	58.67	42.42	45.02	40.18	44.30
Annuity Capital Recovery	11.00	.60	33.51	23.80	24.80	22.28	24.63	17.60	18.97	16.29	18.65
Annuity Capital Recovery	13.00	1.50	55.85	39.78	41.05	37.25	41.01	29.45	31.17	27.18	31.10
Annuity Capital Recovery	16.00	2.00	78.93	56.31	58.50	53.82	58.00	41.71	44.87	39.88	44.03

* A 12 percent discount rate was used in all calculations.

3. There is no significant difference in the expected economic rent between the two leasing systems tested.[47] A paired t statistic was computed for the difference between the system results for each schedule.[48] These t statistics indicated that the hypothesis that the mean system results are equal for the two systems could not be rejected (at the ten percent level).

4. A paired t statistic was also computed between the uniform schedules and each alternative schedule. The results indicated that although the difference in the results for the four schedules is small (less than four percent), it is statistically significant. (T values ranged from seven to ten.) It is interesting to note that there was little difference in the present value of economic rent among the uniform, max economic rent, and environmental schedules.

5. An important implication of this result is that environmental preservation (in terms of lease schedules) can be accomplished with little sacrifice in the present value of economic rent.

6. Another interesting facet of the results is that the max production schedule delivers a significantly lower present value of economic rent than the other schedules.

<u>Schedule Comparison -- Production Streams</u>: The expected production streams of total liquids (oil plus condensate) and total gas (associated and non-associated) under the alternative schedules, prices, and systems are shown in Tables 41-46. Tables 41, 42, and 43 display results using the cash bonus system with the three assumed price sets specified above. Results displayed in Tables 44, 45, and 46 utilize the annuity capital recovery profit share system with the same prices. The present barrel equivalents of production resulting from each schedule is also shown in each table.

The conclusions that emerge from the analysis of production schedules are listed below.

1. Using the ten year uniform leasing schedule, peak OCS liquids production (oil plus NGL) occurs about 1989 at a level of one billion barrels per year (2.9 million barrels per day) assuming a 1976 start date, and excluding production from existing OCS leases. (See Tables 41-46 for production profiles based on other schedules and price assumptions.)

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Note that expected economic rent is different from the government revenue figure used in Part I for the systems comparison. The systems comparison was accomplished assuming risk averse behavior on the part of private sector bidders, and the alternative systems were evaluated in that context. Economic rent is a riskless indicator of total economic surplus.

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A paired t statistic is determined by calculating the characteristics of the distribution of the difference (D) in the paired observations:

$$D_i = X_i - Y_i$$

The t statistic is $t = \overline{D}/S_{\overline{D}}$ with n-1 degrees of freedom (Ostle, 1963, pp. 96 and 121).

Table 41.--Comparison of Production Profiles from Alternative Leasing Schedules Using the Cash Bonus System and Assuming an $11.00 Price for Oil and a $.60 Price for Natural Gas

Year	Ten Year Schedule								Twenty Year Schedule							
	Uniform		Max Econ. Rent		Max Prod.		Environment		Uniform		Max Econ. Rent		Max Prod.		Environment	
	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)
1	.09	.32	.11	.75	.11	.75	.10	.70	.06	.19	.06	.43	.07	.44	.08	.40
2	.25	.90	.30	1.58	.25	1.43	.22	1.46	.13	.43	.15	1.01	.15	1.01	.16	.94
3	.44	1.53	.49	2.21	.41	1.97	.32	2.06	.25	.81	.28	1.56	.25	1.52	.23	1.52
4	.61	2.01	.65	2.51	.51	2.19	.50	2.48	.33	1.16	.39	2.00	.32	1.82	.28	1.88
5	.74	2.37	.77	2.65	.58	2.31	.71	2.81	.43	1.48	.49	2.25	.40	2.00	.33	2.11
6	.90	2.62	.86	2.74	.65	2.38	.90	3.04	.51	1.76	.56	2.39	.46	2.09	.35	2.22
7	.98	2.80	.95	2.84	.69	2.43	1.03	3.13	.59	1.96	.63	2.45	.49	2.13	.45	2.43
8	1.02	2.87	1.02	2.92	.79	2.59	1.12	3.14	.63	2.11	.67	2.49	.51	2.15	.53	2.54
9	1.06	2.97	1.07	2.98	.93	2.78	1.15	3.10	.68	2.26	.68	2.49	.52	2.16	.66	2.71
10	.99	2.87	.96	2.68	.93	2.63	1.03	2.73	.63	2.26	.64	2.31	.44	1.95	.65	2.56
11	.87	2.72	.80	2.54	.91	2.60	.92	2.51	.65	2.25	.58	2.14	.41	1.84	.71	2.52
12	.72	2.59	.69	2.38	.84	2.48	.83	2.39	.62	2.22	.51	2.08	.39	1.78	.71	2.42
13	.60	2.44	.58	2.29	.78	2.42	.62	2.26	.63	2.24	.48	2.08	.38	1.77	.75	2.39
14	.50	2.35	.49	2.20	.70	2.33	.43	2.14	.58	2.27	.49	2.06	.34	1.70	.74	2.34
15	.33	2.15	.41	2.12	.60	2.24	.32	2.06	.53	2.23	.49	2.08	.40	1.82	.75	2.31
16	.26	1.75	.26	1.10	.48	1.24	.21	1.14	.46	1.97	.46	1.52	.41	1.35	.63	1.78
17	.20	1.20	.15	.53	.31	.85	.13	.72	.49	1.83	.45	1.12	.50	1.12	.57	1.35
18	.08	.74	.09	.49	.15	.76	.09	.58	.46	1.62	.45	.92	.53	.98	.44	1.00
19	.04	.56	.04	.36	.04	.59	.05	.28	.45	1.42	.41	.66	.60	.98	.39	.87
20	.02	.33	.03	.35	.03	.57	.03	.11	.37	1.19	.41	.69	.59	1.00	.32	.76
21	.02	.32	.02	.32	.03	.54	.02	.02	.29	.93	.36	.65	.58	1.01	.27	.69
22	.01	.20	.01	.16	.02	.46	.01	.01	.26	.83	.31	.57	.52	.93	.20	.39
23	.00	.19	.00	.12	.01	.24	.00	.00	.23	.72	.23	.49	.48	.85	.17	.34
24		.08		.03	.00	.09			.18	.50	.18	.46	.35	.78	.11	.15
25		.00		.01		.00			.16	.44	.13	.42	.29	.74	.09	.14

Table 41.--Continued

Year	Ten Year Schedule								Twenty Year Schedule							
	Uniform		Max Econ. Rent		Max Prod.		Environment		Uniform		Max Econ. Rent		Max Prod.		Environment	
	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)
26				.00					.06	.36	.11	.41	.16	.64	.06	.04
27									.05	.35	.06	.35	.12	.61	.04	.03
28									.02	.26	.04	.23	.04	.52	.03	.02
29									.01	.20	.01	.16	.02	.47	.02	.01
30									.00	.19	.00	.13	.01	.25	.01	.00
31										.18		.13	.00	.24	.00	
32										.16		.12		.10		
33										.07		.03		.09		
34										.02		.01		.00		
35										.00		.00				
36																
Total Production	10.75	38.89	10.75	38.89	10.75	38.89	10.75	38.89	10.75	38.89	10.75	38.89	10.75	38.89	10.75	38.89
Total PBE*	2.55	8.45	2.59	9.34	2.34	8.77	2.51	9.44	1.87	6.52	1.91	7.91	1.65	7.29	1.80	8.03

*Present barrel (or Mcf) equivalents using a 12 percent discount rate.

Table 42.—Comparison of Production Profiles from Alternative Leasing Schedules Using the Cash Bonus System and Assuming a $13.00 Price for Oil and a $1.50 Price for Natural Gas

Year	Ten Year Schedule								Twenty Year Schedule							
	Uniform		Max Econ. Rent		Max Prod.		Environment		Uniform		Max Econ. Rent		Max Prod.		Environment	
	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)
1	.10	.39	.12	.79	.12	.79	.16	.74	.07	.24	.06	.45	.07	.46	.07	.41
2	.27	1.10	.31	1.68	.26	1.54	.22	1.58	.14	.54	.15	1.05	.16	1.06	.15	.98
3	.48	1.90	.52	2.40	.43	2.20	.34	2.26	.28	1.02	.28	1.65	.26	1.62	.24	1.64
4	.67	2.50	.69	2.84	.56	2.55	.52	2.79	.37	1.44	.40	2.12	.33	1.96	.29	2.05
5	.82	3.06	.84	3.12	.65	2.78	.75	3.24	.47	1.83	.51	2.44	.43	2.22	.35	2.32
6	.99	3.41	.94	3.38	.72	2.95	.95	3.63	.56	2.18	.59	2.62	.49	2.37	.37	2.46
7	1.08	3.70	1.04	3.61	.78	3.08	1.11	3.88	.65	2.46	.67	2.77	.54	2.49	.48	2.74
8	1.12	3.84	1.12	3.81	.89	3.32	1.22	4.06	.70	2.65	.71	2.87	.56	2.56	.56	2.89
9	1.17	4.01	1.18	3.96	1.03	3.67	1.29	4.13	.74	2.85	.74	2.96	.58	2.63	.70	3.16
10	1.09	3.96	1.07	3.74	1.04	3.64	1.14	3.81	.69	2.94	.70	2.83	.51	2.45	.69	3.04
11	.98	3.82	.91	3.62	1.01	3.68	1.04	3.60	.72	3.03	.65	2.77	.48	2.38	.76	3.10
12	.79	3.68	.78	3.47	.92	3.56	.93	3.47	.68	3.05	.59	2.78	.45	2.35	.79	3.04
13	.66	3.51	.66	3.36	.85	3.48	.70	3.32	.69	3.11	.55	2.82	.45	2.38	.81	3.08
14	.55	3.40	.57	3.24	.76	3.38	.51	3.19	.64	3.17	.56	2.83	.40	2.34	.80	3.10
15	.37	3.18	.45	3.15	.67	3.27	.38	3.10	.59	3.14	.56	2.91	.46	2.50	.83	3.15
16	.30	2.65	.29	2.06	.51	2.20	.25	2.11	.52	2.81	.53	2.36	.47	2.01	.71	2.67
17	.22	1.94	.17	1.42	.33	1.73	.15	1.57	.57	2.68	.52	1.98	.56	1.89	.65	2.27
18	.10	1.33	.10	1.29	.17	1.51	.11	1.39	.51	2.35	.51	1.76	.59	1.78	.52	1.86
19	.05	1.07	.05	1.01	.06	1.24	.07	.97	.49	2.14	.46	1.54	.65	1.84	.46	1.74
20	.03	.66	.04	.89	.05	1.14	.05	.67	.40	1.87	.46	1.53	.63	1.80	.39	1.61
21	.02	.54	.03	.68	.04	1.03	.03	.42	.32	1.54	.40	1.48	.62	1.79	.34	1.54
22	.01	.34	.02	.45	.03	.89	.02	.26	.29	1.39	.34	1.29	.56	1.64	.25	1.12
23	.01	.31	.01	.30	.02	.59	.00	.13	.25	1.26	.29	1.15	.51	1.52	.21	1.07
24	.00	.12	.00	.14	.00	.19		.06	.21	.97	.20	1.03	.40	1.38	.14	.73
25		.00		.00		.00		.02	.17	.78	.15	.96	.31	1.32	.11	.71

Table 42.—Continued

Year	Ten Year Schedule								Twenty Year Schedule							
	Uniform		Max Econ. Rent		Max Prod.		Environment		Uniform		Max Econ. Rent		Max Prod.		Environment	
	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)
26								.00	.07	.60	.12	.79	.17	1.15	.08	.47
27									.06	.57	.07	.70	.14	1.10	.06	.43
28									.02	.44	.05	.55	.06	.94	.04	.35
29									.01	.34	.02	.45	.03	.88	.02	.26
30									.01	.32	.01	.31	.02	.60	.02	.18
31									.01	.31	.01	.29	.02	.59	.00	.12
32									.00	.20	.00	.25	.00	.20		.05
33										.11		.13		.19		.04
34										.06		.00		.00		.00
35										.00						
36																
Total Production	11.90	54.39	11.90	54.39	11.90	54.39	11.90	54.39	11.90	54.39	11.90	54.39	11.90	54.39	11.90	54.39
Total PBE*	2.81	11.33	2.83	11.91	2.58	11.37	2.73	12.01	2.06	8.62	2.06	9.58	1.81	8.90	1.94	9.70

*Present barrel (or Mcf) equivalents using a 12 percent discount rate.

Table 43.--Comparison of Production Profiles from Alternative Leasing Schedules Using the Cash Bonus System and Assuming a $16.00 Price for Oil and a $2.00 Price for Natural Gas

Year	Ten Year Schedule								Twenty Year Schedule							
	Uniform		Max Econ. Rent		Max Prod.		Environment		Uniform		Max Econ. Rent		Max Prod.		Environment	
	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)
1	.11	.41	.12	.83	.12	.83	.11	.78	.07	.26	.07	.47	.07	.48	.07	.43
2	.29	1.19	.32	1.79	.27	1.67	.23	1.71	.15	.57	.16	1.11	.16	1.12	.15	1.04
3	.52	2.07	.53	2.63	.45	2.44	.35	2.52	.29	1.09	.29	1.75	.26	1.73	.25	1.75
4	.72	2.75	.72	3.16	.58	2.89	.54	3.14	.39	1.55	.41	2.26	.34	2.13	.30	2.22
5	.89	3.34	.88	3.56	.69	3.23	.78	3.62	.51	2.00	.52	2.64	.44	2.45	.36	2.56
6	1.08	3.83	1.00	3.92	.79	3.51	1.00	4.03	.60	2.39	.60	2.89	.51	2.66	.37	2.76
7	1.18	4.19	1.13	4.25	.87	3.74	1.17	4.35	.70	2.71	.69	3.09	.57	2.83	.49	3.09
8	1.23	4.39	1.23	4.52	1.00	4.04	1.31	4.61	.76	2.94	.74	3.24	.59	2.95	.58	3.28
9	1.28	4.64	1.30	4.72	1.15	4.40	1.37	4.77	.80	3.17	.78	3.38	.62	3.07	.72	3.54
10	1.18	4.65	1.19	4.50	1.16	4.39	1.26	4.51	.75	3.28	.75	3.29	.56	2.94	.72	3.42
11	1.04	4.54	1.02	4.36	1.12	4.41	1.16	4.33	.78	3.41	.71	3.29	.54	2.93	.80	3.48
12	.86	4.40	.88	4.19	1.01	4.28	1.05	4.19	.74	3.48	.65	3.34	.52	2.94	.80	3.43
13	.71	4.22	.73	4.06	.92	4.18	.81	4.03	.75	3.55	.63	3.44	.52	3.02	.87	3.56
14	.59	4.09	.59	3.93	.81	4.07	.59	3.89	.69	3.63	.63	3.48	.47	3.00	.87	3.57
15	.40	3.89	.49	3.82	.68	3.95	.45	3.79	.64	3.64	.64	3.59	.53	3.19	.91	3.66
16	.32	3.28	.32	2.65	.54	2.79	.29	2.72	.56	3.30	.60	3.03	.54	2.68	.79	3.17
17	.24	2.48	.19	1.92	.35	2.20	.16	2.03	.58	3.19	.59	2.62	.63	2.50	.74	2.79
18	.11	1.79	.11	1.66	.18	1.87	.11	1.72	.54	2.86	.57	2.36	.64	2.31	.60	2.34
19	.06	1.46	.06	1.31	.06	1.52	.06	1.25	.52	2.65	.52	2.08	.70	2.32	.54	2.20
20	.04	.99	.05	1.09	.05	1.32	.04	.97	.44	2.37	.51	2.00	.68	2.22	.46	2.03
21	.03	.77	.03	.78	.04	1.12	.03	.70	.36	2.03	.45	1.87	.67	2.17	.40	1.91
22	.02	.55	.02	.49	.03	.91	.02	.45	.32	1.82	.38	1.64	.59	1.96	.30	1.46
23	.02	.45	.01	.29	.02	.57	.01	.25	.28	1.68	.30	1.46	.54	1.81	.24	1.38
24	.00	.19	.00	.11	.00	.21	.00	.12	.23	1.35	.23	1.28	.40	1.62	.16	1.06
25		.00		.00		.00		.03	.19	1.13	.17	1.17	.33	1.50	.12	1.04

Table 43.--Continued

Year	Ten Year Schedule								Twenty Year Schedule							
	Uniform		Max Econ. Rent		Max Prod.		Environment		Uniform		Max Econ. Rent		Max Prod.		Environment	
	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)
26								.01	.08	.90	.13	.94	.18	1.28	.09	.78
27								.00	.07	.82	.08	.82	.15	1.20	.07	.73
28									.03	.70	.06	.62	.06	.99	.04	.58
29									.02	.55	.02	.49	.04	.91	.02	.46
30									.02	.50	.02	.33	.02	.60	.02	.33
31									.02	.45	.01	.29	.02	.58	.01	.24
32									.01	.31	.00	.22	.00	.22	.00	.13
33									.00	.18		.10		.22		.11
34										.10		.01		.01		.04
35										.00		.00		.00		.01
36																
Total Production	12.91	64.53	12.91	64.53	12.91	64.53	12.91	64.53	12.91	64.53	12.91	64.53	12.91	64.53	12.91	64.53
Total PBE*	3.05	13.04	3.04	13.84	2.80	13.23	2.93	13.82	2.22	9.74	2.19	10.95	1.94	10.32	2.05	10.98

*Present barrel (or Mcf) equivalents using a 12 percent discount rate.

Table 44.-Comparison of Production Profiles from Alternative Leasing Schedules Using the Annuity Capital Recovery Profit Share System and Assuming an $11.00 Price for Oil and a $.60 Price for Natural Gas

Year	Ten Year Schedule								Twenty Year Schedule							
	Uniform		Max Econ. Rent		Max Prod.		Environment		Uniform		Max Econ. Rent		Max Prod.		Environment	
	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)
1	.09	.33	.11	.76	.11	.76	.10	.71	.07	.19	.06	.43	.07	.45	.07	.40
2	.26	.95	.31	1.61	.25	1.46	.22	1.52	.13	.44	.15	1.03	.16	1.03	.15	.96
3	.46	1.62	.50	2.25	.42	2.00	.33	2.17	.26	.86	.28	1.59	.25	1.55	.24	1.59
4	.64	2.13	.67	2.56	.53	2.24	.51	2.66	.35	1.24	.40	2.03	.32	1.85	.29	1.99
5	.78	2.54	.80	2.71	.61	2.36	.73	3.02	.45	1.58	.50	2.29	.41	2.04	.34	2.23
6	.96	2.83	.89	2.84	.68	2.44	.93	3.31	.53	1.87	.57	2.43	.47	2.13	.36	2.35
7	1.03	3.03	.99	2.98	.73	2.49	1.07	3.42	.62	2.07	.65	2.50	.51	2.17	.46	2.61
8	1.07	3.11	1.07	3.12	.83	2.65	1.17	3.45	.66	2.23	.69	2.54	.53	2.20	.55	2.74
9	1.11	3.25	1.12	3.21	.97	2.93	1.21	3.41	.70	2.38	.71	2.54	.54	2.21	.68	2.93
10	1.03	3.16	1.01	2.95	.98	2.86	1.08	3.03	.65	2.43	.66	2.36	.47	2.00	.67	2.77
11	.89	3.01	.85	2.81	.95	2.87	.98	2.80	.67	2.44	.61	2.23	.44	1.88	.74	2.78
12	.73	2.87	.72	2.66	.87	2.76	.88	2.67	.63	2.42	.54	2.19	.41	1.81	.74	2.69
13	.60	2.71	.60	2.56	.79	2.69	.65	2.53	.64	2.44	.51	2.21	.40	1.80	.78	2.67
14	.50	2.62	.49	2.46	.71	2.60	.45	2.41	.59	2.48	.51	2.19	.35	1.73	.77	2.62
15	.32	2.41	.40	2.38	.60	2.51	.32	2.32	.54	2.43	.51	2.25	.41	1.86	.79	2.59
16	.26	2.00	.25	1.34	.47	1.48	.20	1.38	.47	2.17	.48	1.70	.42	1.38	.66	2.05
17	.19	1.37	.13	.76	.29	1.09	.10	.86	.50	2.06	.47	1.30	.51	1.22	.60	1.61
18	.07	.90	.07	.72	.14	.99	.07	.71	.47	1.80	.46	1.10	.54	1.13	.47	1.17
19	.03	.71	.03	.59	.04	.82	.04	.34	.45	1.61	.42	.87	.61	1.20	.41	1.04
20	.02	.40	.02	.58	.03	.81	.02	.17	.37	1.37	.42	.92	.60	1.23	.34	.92
21	.02	.39	.02	.47	.03	.78	.01	.01	.30	1.11	.37	.90	.59	1.26	.29	.84
22	.01	.26	.01	.30	.02	.70	.00	.00	.27	1.01	.31	.81	.53	1.18	.20	.47
23	.00	.26	.00	.20	.02	.47			.23	.89	.24	.73	.48	1.10	.17	.42
24		.08		.10	.00	.16			.19	.67	.18	.70	.35	1.03	.10	.22
25		.00		.00		.00			.16	.51	.13	.66	.30	.99	.08	.20

Table 44.-Continued

Year	Ten Year Schedule								Twenty Year Schedule							
	Uniform		Max Econ. Rent		Max Prod.		Environment		Uniform		Max Econ. Rent		Max Prod.		Environment	
	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)
26									.06	.43	.10	.56	.16	.88	.05	.03
27									.05	.42	.06	.50	.13	.86	.04	.02
28									.02	.33	.04	.38	.05	.76	.02	.01
29									.01	.27	.01	.31	.02	.71	.01	.00
30									.00	.26	.00	.20	.02	.48	.00	
31										.26		.20	.02	.47		
32										.16		.20	.00	.16		
33										.07		.10		.16		
34										.02		.00		.00		
35										.00						
36																
Total Production	11.07	42.93	11.07	42.93	11.07	42.93	11.07	42.93	11.07	42.93	11.07	42.93	11.07	42.93	11.07	42.93
Total PBE*	2.65	9.18	2.68	9.93	2.43	9.28	2.60	10.28	1.94	7.04	1.97	8.26	1.71	7.56	1.86	8.67

*Present barrel (or Mcf) equivalents using a 12 percent discount rate.

Table 45.-Comparison of Production Profiles from Alternative Leasing Schedules Using the Annuity Capital Recovery Profit Share System and Assuming a $13.00 Price for Oil and a $1.50 Price for Natural Gas

Year	Ten Year Schedule								Twenty Year Schedule							
	Uniform		Max Econ. Rent		Max Prod.		Environment		Uniform		Max Econ. Rent		Max Prod.		Environment	
	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)
1	.10	.33	.12	.62	.12	.62	.11	.62	.07	.22	.06	.35	.07	.36	.07	.36
2	.28	.98	.32	1.44	.26	1.29	.23	1.40	.15	.46	.16	.83	.16	.84	.15	.83
3	.50	1.72	.52	2.08	.44	1.85	.34	2.08	.28	.92	.29	1.36	.26	1.32	.24	1.44
4	.69	2.31	.71	2.52	.57	2.18	.53	2.66	.38	1.30	.41	1.82	.34	1.64	.30	1.83
5	.85	2.83	.86	2.85	.67	2.41	.76	3.15	.48	1.68	.51	2.12	.43	1.87	.35	2.15
6	1.02	3.26	.96	3.16	.75	2.60	.97	3.56	.57	2.00	.60	2.30	.50	2.01	.38	2.32
7	1.11	3.57	1.07	3.49	.81	2.77	1.13	3.84	.67	2.28	.68	2.47	.55	2.14	.48	2.64
8	1.16	3.73	1.16	3.73	.92	3.11	1.25	4.03	.72	2.48	.73	2.61	.58	2.25	.57	2.83
9	1.21	3.95	1.22	3.96	1.07	3.58	1.30	4.11	.76	2.70	.76	2.73	.60	2.35	.71	3.12
10	1.11	4.01	1.10	3.98	1.07	3.87	1.18	3.96	.70	2.84	.72	2.80	.53	2.33	.71	3.10
11	.95	3.93	.93	3.84	1.03	3.93	1.07	3.72	.73	3.04	.67	2.86	.50	2.36	.78	3.24
12	.78	3.81	.79	3.70	.92	3.86	.96	3.52	.68	3.06	.60	2.87	.46	2.33	.78	3.16
13	.64	3.62	.64	3.56	.83	3.76	.72	3.35	.69	3.16	.57	2.90	.46	2.37	.83	3.16
14	.52	3.50	.51	3.38	.73	3.64	.51	3.21	.64	3.19	.57	3.00	.40	2.37	.82	3.15
15	.34	3.26	.42	3.26	.62	3.51	.37	3.12	.59	3.21	.57	3.01	.45	2.58	.85	3.19
16	.28	2.71	.26	2.10	.49	2.41	.22	2.12	.51	2.85	.53	2.54	.46	2.13	.72	2.70
17	.20	1.98	.14	1.46	.30	1.83	.11	1.57	.53	2.74	.51	2.14	.55	2.07	.67	2.29
18	.08	1.32	.08	1.27	.15	1.54	.07	1.39	.50	2.42	.50	1.94	.58	1.98	.53	1.88
19	.03	1.05	.03	1.00	.04	1.23	.03	.96	.48	2.22	.44	1.67	.64	2.10	.47	1.76
20	.02	.65	.03	.88	.04	1.14	.02	.66	.40	1.88	.45	1.66	.63	2.05	.39	1.63
21	.02	.53	.02	.67	.03	1.03	.01	.41	.32	1.62	.40	1.60	.62	2.04	.34	1.56
22	.01	.33	.01	.44	.03	.88	.00	.24	.29	1.45	.33	1.40	.55	1.87	.24	1.13
23	.01	.31	.00	.29	.02	.58		.10	.25	1.32	.25	1.19	.50	1.74	.20	1.07
24	.00	.11		.13	.00	.18		.04	.20	1.02	.19	1.06	.37	1.51	.12	.73
25		.00		.00		.00		.00	.17	.82	.13	1.00	.31	1.43	.09	.70

Table 45.-Continued

Year	Ten Year Schedule								Twenty Year Schedule							
	Uniform		Max Econ. Rent		Max Prod.		Environment		Uniform		Max Econ. Rent		Max Prod.		Environment	
	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)
26									.06	.60	.11	.82	.16	1.20	.06	.46
27									.05	.56	.06	.69	.13	1.14	.04	.43
28									.02	.43	.04	.54	.05	.94	.02	.33
29									.01	.34	.01	.45	.03	.89	.00	.24
30									.01	.31	.01	.32	.02	.60		.16
31									.01	.31	.00	.29	.02	.60		.10
32									.00	.20		.24	.00	.20		.04
33										.11		.13		.20		.03
34										.06		.00		.00		.00
35										.00						
36																
Total Production	11.91	53.79	11.91	53.79	11.91	53.79	11.91	53.79	11.91	53.79	11.91	53.79	11.91	53.79	11.91	53.79
Total PBE*	2.85	11.00	2.87	11.41	2.62	10.64	2.77	11.72	2.09	8.28	2.09	8.94	1.84	8.14	1.96	9.37

*Present barrel (or Mcf) equivalents using a 12 percent discount rate.

Table 46.-Comparison of Production Profiles from Alternative Leasing Schedules Using the Annuity Capital Recovery Profit Share System and Assuming a $16.00 Price for Oil and a $2.00 Price for Natural Gas

Year	Ten Year Schedule								Twenty Year Schedule							
	Uniform		Max Econ. Rent		Max Prod.		Environment		Uniform		Max Econ. Rent		Max Prod.		Environment	
	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)
1	.11	.42	.12	.83	.12	.83	.11	.78	.08	.26	.07	.47	.07	.49	.07	.44
2	.30	1.18	.32	1.80	.27	1.67	.23	1.72	.16	.57	.16	1.12	.16	1.13	.15	1.05
3	.53	2.05	.54	2.61	.46	2.42	.35	2.54	.30	1.10	.29	1.76	.26	1.73	.25	1.76
4	.74	2.73	.73	3.14	.60	2.85	.55	3.17	.40	1.56	.41	2.28	.35	2.12	.30	2.24
5	.92	3.31	.90	3.51	.71	3.17	.79	3.68	.52	1.98	.53	2.64	.45	2.43	.36	2.58
6	1.10	3.79	1.03	3.86	.81	3.42	1.01	4.11	.61	2.36	.61	2.87	.52	2.63	.39	2.78
7	1.20	4.16	1.15	4.17	.90	3.63	1.20	4.42	.72	2.68	.70	3.06	.58	2.78	.50	3.12
8	1.25	4.36	1.26	4.42	1.03	3.93	1.34	4.66	.77	2.90	.76	3.20	.61	2.89	.59	3.31
9	1.30	4.60	1.33	4.61	1.18	4.32	1.40	4.78	.82	3.14	.80	3.34	.64	3.00	.73	3.60
10	1.21	4.59	1.22	4.41	1.19	4.32	1.30	4.49	.77	3.24	.77	3.24	.57	2.86	.73	3.50
11	1.05	4.48	1.04	4.30	1.14	4.35	1.19	4.28	.79	3.37	.73	3.22	.56	2.83	.81	3.57
12	.86	4.33	.89	4.13	1.02	4.21	1.08	4.14	.75	3.43	.67	3.26	.53	2.83	.82	3.52
13	.71	4.15	.74	4.00	.92	4.12	.83	3.97	.76	3.52	.64	3.34	.53	2.90	.89	3.59
14	.58	4.02	.59	3.86	.81	4.00	.61	3.83	.70	3.60	.64	3.27	.48	2.87	.89	3.62
15	.39	3.79	.49	3.75	.68	3.88	.45	3.72	.65	3.61	.65	3.47	.53	3.06	.93	3.70
16	.31	3.20	.31	2.56	.53	2.71	.27	2.63	.56	3.26	.61	2.90	.54	2.54	.81	3.20
17	.23	2.41	.17	1.83	.33	2.14	.14	1.94	.58	3.14	.60	2.49	.63	2.40	.76	2.79
18	.10	1.74	.10	1.62	.17	1.83	.09	1.63	.56	2.80	.57	2.22	.65	2.24	.61	2.32
19	.05	1.42	.05	1.27	.05	1.50	.04	1.16	.52	2.60	.52	1.97	.71	2.27	.56	2.16
20	.03	.96	.04	1.07	.05	1.33	.03	.83	.44	2.33	.51	1.93	.69	2.18	.47	1.96
21	.03	.75	.03	.79	.04	1.15	.02	.55	.36	1.99	.45	1.84	.67	2.14	.41	1.83
22	.02	.50	.02	.52	.03	.96	.01	.34	.32	1.80	.38	1.61	.59	1.95	.30	1.37
23	.01	.43	.01	.33	.02	.62	.00	.14	.28	1.65	.29	1.44	.54	1.81	.24	1.29
24	.00	.18	.00	.15	.00	.20		.06	.22	1.32	.23	1.26	.39	1.63	.15	.91
25		.00		.00		.00		.00	.19	1.10	.16	1.16	.33	1.53	.11	.88

Table 46.--Continued

Year	Ten Year Schedule								Twenty Year Schedule							
	Uniform		Max Econ. Rent		Max Prod.		Environment		Uniform		Max Econ. Rent		Max Prod.		Environment	
	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)	Liquids (bil. bbls.)	Gas (Tcf)
26									.08	.88	.13	.94	.18	1.32	.08	.62
27									.07	.80	.07	.83	.15	1.24	.06	.57
28									.03	.64	.05	.65	.06	1.04	.03	.45
29									.02	.51	.02	.53	.03	.97	.01	.34
30									.02	.46	.01	.38	.02	.66	.00	.23
31									.02	.43	.01	.34	.02	.64		.14
32									.01	.29	.00	.27	.00	.22		.06
33									.00	.18		.15		.22		.06
34										.09		.01		.01		.01
35										.00		.00		.00		.00
36																
Total Production	13.06	63.55	13.06	63.55	13.06	63.55	13.06	63.55	13.06	63.55	13.06	63.55	13.06	63.55	13.06	63.55
Total PBE*	3.10	12.90	3.09	13.65	2.84	13.01	2.97	13.82	2.26	9.64	2.23	10.82	1.97	10.15	2.08	11.04

*Present barrel (or Mcf) equivalent using a 12 percent discount rate.

2. New OCS production never could be expected to completely replace the current levels of imports with any of the leasing schedules. This conclusion, of course, is dependent upon the economic and geologic assumptions of this analysis (USDI, 1975, p. 86).

3. OCS primary reserves would be exhausted by 2015 assuming a twenty year leasing schedule and by 2005 assuming a ten year schedule (to 200 meters).

4. Total expected liquids production from the OCS is 11-13 billion barrels; total expected gas production is 39-64 billion Mcf (39-64 Tcf) depending on resource prices and lease system used. These estimates depend upon all of the reserve, cost, and economic assumptions and analyses described throughout this paper.

The estimates fall into the lower end of the range of discoverable reserve estimates presented by Miller, et al.: 10-49 billion barrels for oil and 42-181 trillion cubic feet for gas. Our expected production estimates were in the lower end of the range for two reasons: (1) We considered only seventy-five percent of the total resources in our leasing schedules, and (2) the economic analysis resulted in some of the oil and gas not being produced because production costs were too high relative to product prices.

5. Gas production is more responsive to changes in price than oil production (varying from 38 to 64 billion Mcf). This conclusion implies that deregulating natural gas (or substantially raising the price) could stimulate new production.

6. The difference in present barrel equivalent of production among the uniform, max economic rent, and environmental preservation schedules is small. This result again implies that the environmental considerations in the leasing schedule are not costly to society.

7. The schedule which was designed to maximize the present barrel equivalent of production did not accomplish this objective. In fact, this schedule achieved the lowest expected present barrel equivalent of production and lowest expected economic rent of all alternative schedules. Although the expected production excluding economic considerations is high for the maximim production schedule, when cost factors and other economic variables enter the process, the expected amount of production is reduced because of the interaction of economic variables. The schedule to maximize the contribution maximizes the present barrel equivalent of production. On reflection, this result is reasonable, and the max production schedule is not an important alternative.

In general, the comparison of alternative leasing schedules revealed that the differences among the selected schedules were relatively minor. However, a number of potential schedule issues were not covered in this comparison. Issues arising from regional environmental and production trade-offs or the social welfare implications of a delay in OCS leasing (to use foreign oil first) are beyond the scope of this analysis.

APPENDIX A

UNIT EFFORT TABULATION BY SUBREGION AND FIELD SIZE

Table A-1.--Expected OCS Region 1 Fields, by Size Category, Evenly Divided into Ten Exploration Units*

Exploration Unit	Number of Small Fields	Number of Medium Fields	Number of Large Fields	Total Number of Fields
		Oil		
1	1	3	3	7
2	3	2	2	7
3	3	1	3	7
4	2	3	3	8
5	3	3	2	8
6	0	6	2	8
7	4	3	0	7
8	4	1	2	7
9	6	0	1	7
10	7	0	0	7
Total	33	22	18	73
		Non-associated Natural Gas		
1	1	0	1	2
2	0	2	1	3
3	1	1	1	3
4	1	1	1	3
5	2	0	1	3
6	1	1	1	3
7	1	2	0	3
8	2	1	0	3
9	2	1	0	3
10	1	0	1	2
Total	12	9	7	28

*Based upon 75 percent of estimated undiscovered recoverable resources.

Table A-2.--Expected OCS Region 2 Fields, by Size Category, Evenly Divided into Ten Exploration Units*

Exploration Unit	Number of Small Fields	Number of Medium Fields	Number of Large Fields	Total Number of Fields
		Oil		
1	1	2	3	6
2	2	3	1	6
3	3	1	3	7
4	3	2	2	7
5	1	3	3	7
6	3	3	1	7
7	4	1	2	7
8	5	0	1	6
9	4	1	1	6
10	5	1	0	6
Total	31	17	17	65
		Non-associated Natural Gas		
1	1	0	1	2
2	0	2	0	2
3	0	0	2	2
4	2	1	0	3
5	2	0	1	3
6	1	1	1	3
7	1	0	1	2
8	1	1	0	2
9	1	1	0	2
10	2	0	0	2
Total	11	6	6	23

*Based upon 75 percent of estimated undiscovered recoverable resources.

Table A-3.--Expected OCS Region 3 Fields, by Size Category, Evenly Divided into Ten Exploration Units*

Exploration Unit	Number of Small Fields	Number of Medium Fields	Number of Large Fields	Total Number of Fields
		Oil		
1	3	2	3	8
2	3	3	3	9
3	4	3	2	9
4	2	5	2	9
5	3	3	3	9
6	6	3	0	9
7	7	1	1	9
8	8	1	0	9
9	8	1	0	9
10	4	4	0	8
Total	48	26	14	88
		Non-associated Natural Gas		
1	1	0	1	2
2	0	2	1	3
3	2	0	1	3
4	1	1	1	3
5	2	0	1	3
6	2	1	0	3
7	1	2	0	3
8	3	0	0	3
9	2	1	0	3
10	1	2	0	3
Total	15	9	5	29

*Based upon 75 percent of estimated undiscovered recoverable resources.

Table A-4.--Expected OCS Region 4 Fields, by Size Category, Evenly Divided into Ten Exploration Units*

Exploration Unit	Number of Small Fields	Number of Medium Fields	Number of Large Fields	Total Number of Fields
		Oil		
1	0	0	0	0
2	0	0	1	1
3	0	0	0	0
4	0	0	0	0
5	0	0	0	0
6	0	0	1	1
7	0	0	0	0
8	0	0	0	0
9	0	0	1	1
10	0	0	0	0
Total	0	0	3	3
		Non-associated Natural Gas		
1	0	0	0	0
2	0	0	1	1
3	0	0	0	0
4	0	0	0	0
5	0	0	0	0
6	0	0	0	0
7	0	0	0	0
8	0	1	0	1
9	0	0	0	0
10	0	0	0	0
Total	0	1	1	2

*Based upon 75 percent of estimated undiscovered recoverable resources.

Table A-5.--Expected OCS Region 5 Fields, by Size Category, Evenly Divided into Ten Exploration Units*

Exploration Unit	Number of Small Fields	Number of Medium Fields	Number of Large Fields	Total Number of Fields
		Oil		
1	1	1	0	2
2	0	2	0	2
3	0	0	2	2
4	2	0	0	2
5	2	1	0	3
6	1	0	1	2
7	2	0	0	2
8	2	0	0	2
9	2	0	0	2
10	2	0	0	2
Total	14	4	3	21
		Non-associated Natural Gas		
1	0	1	0	1
2	0	0	0	0
3	1	0	0	1
4	0	0	0	0
5	1	0	0	1
6	0	1	0	1
7	0	0	1	1
8	0	0	0	0
9	1	0	0	1
10	0	0	0	0
Total	3	2	1	6

*Based upon 75 percent of estimated undiscovered recoverable resources.

Table A-6.--Expected OCS Region 6 Fields, by Size Category, Evenly Divided into Ten Exploration Units*

Exploration Unit	Number of Small Fields	Number of Medium Fields	Number of Large Fields	Total Number of Fields
		Oil		
1	0	0	0	0
2	0	0	0	0
3	0	0	1	1
4	0	0	0	0
5	0	0	0	0
6	0	0	0	0
7	0	0	0	0
8	0	1	0	1
9	0	0	0	0
10	0	0	0	0
Total	0	1	1	2
		Non-associated Natural Gas		
1	0	0	0	0
2	0	0	0	0
3	0	0	0	0
4	0	0	0	0
5	0	0	1	1
6	0	0	0	0
7	0	0	0	0
8	0	0	0	0
9	0	0	0	0
10	0	0	0	0
Total	0	0	1	1

*Based upon 75 percent of estimated undiscovered recoverable resources.

Table A-7.--Expected OCS Region 7 Fields, by Size Category, Evenly Divided into Ten Exploration Units*

Exploration Unit	Number of Small Fields	Number of Medium Fields	Number of Large Fields	Total Number of Fields
		Oil		
1	0	1	0	1
2	0	0	0	0
3	1	0	0	1
4	0	0	0	0
5	1	0	0	1
6	0	0	0	0
7	0	0	1	1
8	0	0	0	0
9	1	0	0	1
10	0	0	0	0
Total	3	1	1	5
		Non-associated Natural Gas		
1	0	0	0	0
2	0	0	0	0
3	0	1	0	1
4	0	0	0	0
5	0	0	0	0
6	0	0	0	0
7	0	0	0	0
8	1	0	0	1
9	0	0	0	0
10	0	0	0	0
Total	1	1	0	2

*Based upon 75 percent of estimated undiscovered recoverable resources.

Table A-8.--Expected OCS Region 8 Fields, by Size Category, Evenly Divided into Ten Exploration Units*

Exploration Unit	Number of Small Fields	Number of Medium Fields	Number of Large Fields	Total Number of Fields
		Oil		
1	0	0	1	1
2	0	1	0	1
3	0	0	1	1
4	0	0	1	1
5	0	0	1	1
6	0	0	1	1
7	0	1	0	1
8	1	0	0	1
9	0	0	1	1
10	0	0	1	1
Total	1	2	7	10
		Non-associated Natural Gas		
1	0	0	0	0
2	0	0	0	0
3	0	0	1	1
4	0	0	0	0
5	0	0	0	0
6	0	0	0	0
7	0	0	0	0
8	1	0	0	1
9	0	0	0	0
10	0	0	0	0
Total	1	0	1	2

*Based upon 75 percent of estimated undiscovered recoverable resources.

Table A-9.--Expected OCS Region 9 Fields, by Size Category, Evenly Divided into Ten Exploration Units*

Exploration Unit	Number of Small Fields	Number of Medium Fields	Number of Large Fields	Total Number of Fields
		Oil		
1	1	2	2	5
2	2	1	2	5
3	4	0	1	5
4	2	3	0	5
5	5	0	0	5
6	2	2	1	5
7	5	0	0	5
8	4	1	0	5
9	4	1	0	5
10	5	0	0	5
Total	34	10	6	50
		Non-associated Natural Gas		
1	5	3	5	13
2	6	4	3	13
3	7	3	3	13
4	9	2	2	13
5	10	3	1	14
6	14	0	0	14
7	9	4	0	13
8	13	0	0	13
9	12	1	0	13
10	10	3	0	13
Total	95	23	14	132

*Based upon 75 percent of estimated undiscovered recoverable resources.

Table A-10.--Expected OCS Region 10 Fields, by Size Category, Evenly Divided into Ten Exploration Units*

Exploration Unit	Number of Small Fields	Number of Medium Fields	Number of Large Fields	Total Number of Fields
		Oil		
1	0	0	0	0
2	0	0	1	1
3	0	0	0	0
4	0	1	0	1
5	0	0	0	0
6	0	0	1	1
7	0	0	0	0
8	0	0	0	0
9	0	0	1	1
10	0	0	0	0
Total	0	1	3	4
		Non-associated Natural Gas		
1	0	0	0	0
2	0	0	0	0
3	0	0	0	0
4	0	0	0	0
5	0	0	1	1
6	0	0	0	0
7	0	0	0	0
8	0	0	0	0
9	0	0	0	0
10	0	0	0	0
Total	0	0	1	1

*Based upon 75 percent of estimated undiscovered recoverable resources.

Table A-11.--Expected OCS Region 11 Fields, by Size Category, Evenly Divided into Ten Exploration Units*

Exploration Unit	Number of Small Fields	Number of Medium Fields	Number of Large Fields	Total Number of Fields
		Oil		
1	0	0	0	0
2	0	0	1	1
3	0	0	0	0
4	0	1	0	1
5	0	0	0	0
6	0	0	1	1
7	0	0	0	0
8	0	0	0	0
9	0	0	1	1
10	0	0	0	0
Total	0	1	3	4
		Non-associated Natural Gas		
1	0	0	0	0
2	0	0	1	1
3	0	0	0	0
4	0	0	0	0
4	0	0	0	0
6	0	1	0	1
7	0	0	0	0
8	0	0	0	0
9	0	0	1	1
10	0	0	0	0
Total	0	1	2	3

*Based upon 75 percent of estimated undiscovered recoverable resources.

Table A-12.--Expected OCS Region 12 Fields, by Size Category, Evenly Divided into Ten Exploration Units*

Exploration Unit	Number of Small Fields	Number of Medium Fields	Number of Large Fields	Total Number of Fields
		Oil		
1	0	0	1	1
2	0	1	0	1
3	0	0	1	1
4	0	0	1	1
5	0	0	1	1
6	0	0	1	1
7	1	0	0	1
8	1	0	0	1
9	0	1	0	1
10	0	0	0	0
Total	2	2	5	9
		Non-associated Natural Gas		
1	0	0	0	0
2	0	0	1	1
3	0	0	0	0
4	0	0	0	0
5	0	0	0	0
6	0	1	0	1
7	0	0	0	0
8	0	0	0	0
9	0	0	1	1
10	0	0	0	0
Total	0	1	2	3

*Based upon 75 percent of estimated undiscovered recoverable resources.

Table A-13.--Expected OCS Region 13 Fields, By Size Category, Evenly Divided into Ten Exploration Units*

Exploration Unit	Number of Small Fields	Number of Medium Fields	Number of Large Fields	Total Number of Fields
		Oil		
1	0	0	0	0
2	0	0	1	1
3	0	0	0	0
4	1	0	0	1
5	0	0	0	0
6	0	1	0	1
7	0	0	0	0
8	0	0	1	1
9	0	0	0	0
10	0	0	1	1
Total	1	1	3	5
		Non-associated Natural Gas		
1	0	0	0	0
2	0	0	0	0
3	0	0	1	1
4	0	0	0	0
5	0	0	0	0
6	1	0	0	1
7	0	0	0	0
8	0	0	0	0
9	1	0	0	1
10	0	0	0	0
Total	2	0	1	3

*Based upon 75 percent of estimated undiscovered recoverable resources.

Table B-1.--Results of Leasing System Simulation for Petroleum Using a Cash Bonus Bid Variable with a 16.67 Percent Royalty by Province and Reservoir Size[a]

Province and Field Size[b]	ATNPV[c] (million $)	Tax (P.V.-million $)	Royalty (P.V.-million $)	Total Economic Rent (P.V.-million $)	Average Production Cost (million $)	Percent Chance of Less than Normal Profit	Reserve Discovery Size (million bbls.)	Installed Capacity (million bbls.)	Production Time Horizon (years)	Expected Oil Production (million blls.)	Expected Gas Production (million Mcf)
1. Arctic Ocean											
large	13.1	47.9	37.8	98.8	130.7	75.5	262.5	28.4	13.1	61.2	35.7
2. Central Chukchi											
large	7.7	41.0	32.7	81.4	117.2	78.5	257.9	28.1	12.9	52.7	28.2
3. Bering Sea											
large	14.5	30.8	23.7	69.0	75.2	79.5	199.8	22.4	11.6	37.9	18.5
4. Gulf of Alaska											
large	379.4	301.6	186.2	867.2	260.0	48.5	572.3	71.1	9.0	278.2	175.3
medium	6.8	20.1	15.9	42.8	53.8	73.5	99.8	10.7	12.4	25.2	15.9
5. Cook Inlet											
large	98.8	109.1	73.8	281.7	167.4	40.5	205.4	25.0	9.7	114.5	48.8
medium	16.8	35.5	27.5	79.8	87.4	54.0	102.8	10.9	13.2	45.5	19.4
6. North Pacific											
large	262.3	198.4	116.1	576.8	124.2	66.0	556.4	69.1	9.0	178.5	62.8
medium	12.0	19.0	13.9	44.9	39.9	72.5	83.9	10.2	9.6	21.4	75.3
7. Santa Cruz											
large	57.9	56.1	35.9	149.9	68.4	64.5	163.3	20.3	9.0	54.7	11.7
medium	15.3	22.8	16.6	54.7	46.7	66.5	80.9	9.7	9.8	25.6	54.8
8. S. California											
large	350.3	265.4	147.0	762.7	124.1	14.0	281.2	34.9	9.0	229.6	50.5
medium	76.5	66.1	41.1	183.7	65.6	12.0	76.5	9.5	9.0	63.9	14.1
small	3.2	8.5	6.9	18.6	23.4	48.5	22.7	2.6	10.7	10.9	2.4

Table B-1.--Continued

Province and Field Size[b]	ATNPV[c] (million $)	Tax (P.V.-million $)	Royalty (P.V.-million $)	Total Economic Rent (P.V.-million $)	Average Production Cost (million $)	Percent Chance of Less than Normal Profit	Reserve Discovery Size (million bbls.)	Installed Capacity (million bbls.)	Production Time Horizon (years)	Expected Oil Production (million bbls.)	Expected Gas Production (million Mcf)
9. Central and Western Gulf											
large	252.0	194.1	107.5	553.6	95.2	12.0	169.3	21.0	9.0	140.6	541.1
medium	98.3	81.3	48.7	228.3	66.9	6.5	72.5	9.0	9.0	63.6	244.9
small	1.0	6.1	5.1	12.2	18.7	56.0	16.1	1.8	10.6	6.7	25.8
10. MAFLA											
large	272.4	201.8	112.5	586.7	91.6	42.0	314.1	39.0	9.0	173.5	35.4
medium	46.3	41.4	26.0	113.7	44.1	42.0	72.4	9.0	9.0	39.9	8.1
11. North Atlantic											
large	171.4	151.5	96.5	419.4	166.8	56.5	345.3	42.9	9.0	140.1	161.4
medium	5.9	19.0	15.2	40.0	52.3	74.0	94.4	10.0	12.6	23.8	27.4
12. Central Atlantic											
large	246.5	196.6	117.4	560.5	150.2	44.0	331.6	41.2	9.0	176.8	115.7
medium	25.8	33.1	23.8	82.7	62.6	54.0	82.8	10.0	9.7	36.0	23.5
13. South Atlantic											
large	105.1	80.4	45.9	231.4	45.4	66.5	222.2	27.6	9.0	70.2	29.7
medium	24.5	23.5	14.9	62.9	27.4	66.0	70.9	8.8	9.0	22.8	96.0

[a] The following values were used for all simulations: mean price of $11.00 per barrel of oil and $.60 per Mcf of associated gas; and a 12 percent discount rate for all present value calculations.

[b] For each province, reservoir sizes which are uneconomic to develop are not displayed.

[c] After tax net present value.

Table B-2.--Results of Leasing System Simulation for Non-associated Natural Gas Using a Cash Bonus Bid Variable with a 16.67 Percent Royalty by Province and Field Size[a]

Province and Field Size[b]	ATNPV[c] (Million $)	Tax (P.V.-million $)	Royalty (P.V.-million $)	Total Economic Rent (P.V.-million $)	Average Production Cost (million $)	Percent Chance of Less than Normal Profit	Reserve Discovery Size (million Mcf)	Installed Capacity (million $)	Production Time Horizon (years)	Expected Natural Gas Production (million Mcf)	Expected NGL Production (million bbls.)
1. Arctic Ocean					No Development						
2. Central Chukchi					No Development						
3. Bering Sea					No Development						
4. Gulf of Alaska											
large	131.1	134.7	83.7	349.5	153.9	50.5	4071.0	289.5	15.0	1994.8	65.8
5. Cook Inlet											
large	15.0	29.9	21.4	66.3	62.5	68.5	1677.0	111.3	17.3	528.3	17.4
6. North Pacific											
large	101.5	94.6	55.6	251.7	82.6	62.0	3491.0	248.3	15.0	1344.0	44.4
7. Santa Cruz											
large	10.3	18.6	12.9	41.8	35.8	72.5	1147.0	80.8	15.3	309.7	10.2
8. S. California											
large	118.7	103.9	57.7	280.3	66.3	18.0	1682.0	119.7	15.0	1387.7	45.8
medium	19.4	22.4	15.1	56.9	33.9	28.0	500.6	35.6	15.0	362.9	12.0
9. Central and Western Gulf											
large	64.9	60.5	35.1	160.5	50.5	22.0	1076.0	76.5	15.0	644.7	27.9
medium	18.9	22.1	14.9	55.9	33.7	28.0	494.0	35.1	15.0	358.2	11.8
10. MAFLA											
large	111.9	97.4	53.2	262.5	56.9	38.0	2042.0	145.2	15.0	1276.3	42.1
medium	13.0	16.6	11.1	40.7	26.1	46.5	502.1	35.7	15.0	266.1	8.8

Table B-2.--Continued

Province and Field Size[b]	ATNPV[c] (million $)	Tax (P.V.-million $)	Royalty (P.V.-million $)	Total Economic Rent (P.V.-million $)	Average Production Cost (million $)	Percent Chance of Less than Normal Profit	Reserve Discovery Size (million Mcf)	Installed Capacity (million $)	Production Time Horizon (years)	Expected Natural Gas Production (million Mcf)	Expected NGL Production (million bbls.)
11. North Atlantic											
large	50.6	63.6	42.0	156.2	96.8	62.0	2634.0	186.1	15.2	1000.9	33.0
12. Central Atlantic											
large	85.0	86.4	52.5	223.9	91.7	46.0	2306.0	164.0	15.0	1256.8	41.5
13. South Atlantic											
large	40.9	38.3	21.9	101.1	30.3	62.0	1389.0	98.8	15.0	527.8	17.4
medium	5.4	9.4	6.5	21.3	17.6	68.0	479.6	34.1	15.0	155.9	5.1

[a] The following values were used for all simulations: mean price of $.60 per Mcf of natural gas and $11.00 per barrel of natural gas liquids; and a 12 percent discount rate for all present value calculations.

[b] For each province, reservoir sizes which are uneconomic to develop are not displayed.

[c] After tax net present value.

Table B-3.--Results of Leasing System Simulation for Petroleum Using a Cash Bonus Bid Variable with a 16.67 Percent Royalty by Province and Reservoir Size[a]

Province and Field Size[b]	ATNPV[c] (million $)	Tax (P.V.-million $)	Royalty (P.V.-million $)	Total Economic Rent (P.V.-million $)	Average Production Cost (million $)	Percent Chance of Less than Normal Profit	Reserve Discovery Size (million bbls.)	Installed Capacity (million bbls.)	Production Time Horizon (years)	Expected Oil Production (million bbls.)	Expected Gas Production (million Mcf)
1. Arctic Ocean											
large	39.9	77.8	56.0	173.7	166.7	66.0	221.0	25.0	12.0	72.3	42.3
2. Central Chukchi											
large	31.2	67.5	49.1	147.8	150.8	68.5	218.1	24.5	12.0	64.2	34.3
3. Bering Sea											
large	31.4	44.1	31.9	107.4	86.9	76.5	185.1	22.2	9.9	40.3	19.6
4. Gulf of Alaska											
large	504.0	387.6	228.5	1120.1	261.2	48.0	568.4	70.6	9.0	278.9	175.7
medium	20.0	30.9	23.2	74.1	67.4	66.5	90.9	10.6	10.5	28.8	18.2
5. Cook Inlet											
large	149.1	145.6	94.0	388.7	183.6	34.0	191.9	23.8	9.1	119.5	50.9
medium	35.7	57.3	41.1	134.1	115.9	34.0	87.7	9.7	12.4	55.4	23.6
6. North Pacific											
large	334.7	247.4	140.5	722.6	125.0	66.0	550.2	68.4	9.0	179.2	63.1
medium	21.4	24.9	17.4	63.7	42.1	72.0	81.7	10.1	9.0	22.0	7.7
7. Santa Cruz											
large	80.4	70.9	43.8	195.1	70.7	62.5	157.9	19.6	9.0	55.9	12.0
medium	26.0	29.6	20.6	76.2	49.5	64.5	79.4	9.8	9.1	26.2	5.6
8. S. California											
large	437.6	324.8	176.5	938.9	124.7	12.5	278.6	34.6	9.0	230.1	50.6
medium	102.3	81.3	49.4	233.0	66.1	10.5	76.0	9.4	9.0	64.1	14.1
small	8.1	13.9	10.2	32.2	29.9	30.0	20.1	2.4	10.0	13.4	3.0

Table B-3.--Continued

Province and Field Size[b]	ATNPV[c] (million $)	Tax (P.V.-million $)	Royalty (P.V.-million $)	Total Economic Rent (P.V.-million $)	Average Production Cost (million $)	Percent Chance of Less than Normal Profit	Reserve Discovery Size (million bbls.)	Installed Capacity (million bbls.)	Production Time Horizon (years)	Expected Oil Production (million bbls.)	Expected Gas Production (million Mcf)
9. Central and Western Gulf											
large	385.8	285.4	152.9	824.1	96.8	8.5	164.2	20.4	9.0	141.8	545.9
medium	158.9	121.0	68.9	348.8	67.3	6.0	71.9	8.9	9.0	63.8	245.6
small	9.8	14.9	10.5	35.2	29.0	20.0	13.0	1.6	9.6	9.8	37.7
10. MAFLA											
large	339.8	246.7	135.1	721.6	92.3	40.5	310.1	38.5	9.0	174.2	35.5
medium	62.8	50.8	31.3	144.9	44.5	40.5	71.6	8.9	9.0	40.2	8.2
11. North Atlantic											
large	254.9	207.0	126.9	588.8	180.1	50.5	318.1	39.5	9.0	147.1	169.5
medium	20.6	31.0	23.3	74.9	67.3	66.0	84.1	9.8	10.4	27.5	31.7
12. Central Atlantic											
large	325.1	250.9	144.0	720.0	150.2	44.0	331.6	41.2	9.0	176.8	115.7
medium	43.3	44.4	30.3	118.0	66.5	52.0	80.6	10.0	9.0	36.9	24.1
13. South Atlantic											
large	134.8	99.8	55.7	290.3	45.7	66.0	219.7	27.3	9.0	70.5	29.8
medium	34.6	29.4	18.1	82.1	27.6	66.0	70.3	8.7	9.0	22.9	9.7

[a] The following values were used for all simulations: mean price of $13.00 per barrel of oil and $1.50 per Mcf of associated gas; and a 12 percent discount rate for all present value calculations.

[b] For each province, reservoir sizes which are uneconomic to develop are not displayed.

[c] After tax net present value.

Table B-4.--Results of Leasing System Simulation for Non-associated Natural Gas Using a Cash Bonus Bid Variable with a 16.67 Percent Royalty by Province and Field Size[a]

Province and Field Size[b]	ATNPV[c] (million $)	Tax (P.V.-million $)	Royalty (P.V.-million $)	Total Economic Rent (P.V.-million $)	Average Production Cost (million $)	Percent Chance of Less than Normal Profit	Reserve Discovery Size (million Mcf)	Installed Capacity (million Mcf)	Production Time Horizon (years)	Expected Natural Gas Production (million Mcf)	Expected NGL Production (million bbls.)
1. Arctic Ocean											
large	34.4	62.0	41.7	138.1	112.6	68.5	1553.0	108.6	15.6	489.2	16.1
2. Central Chukchi											
large	28.1	55.8	38.0	121.9	106.8	70.0	1469.0	102.1	15.8	448.0	14.8
3. Bering Sea											
large	28.3	41.6	27.5	97.4	68.3	70.5	1125.0	79.6	15.1	326.3	10.8
4. Gulf of Alaska											
large	388.8	333.1	177.8	899.7	168.2	42.0	3624.0	257.7	15.0	2101.9	69.4
medium	15.3	26.2	18.0	59.5	49.0	62.5	569.6	40.2	15.2	210.8	7.0
5. Cook Inlet											
large	101.3	105.3	63.3	269.9	110.6	30.5	1084.0	77.1	15.0	753.4	24.9
medium	25.1	37.3	26.0	88.4	68.1	44.5	557.6	39.1	15.4	309.5	10.2
6. North Pacific											
large	268.0	220.4	114.7	603.1	85.8	58.5	3312.0	235.6	15.0	1374.5	45.4
medium	17.4	22.5	14.6	54.5	33.2	62.5	467.2	33.2	15.0	175.2	5.8
7. Santa Cruz											
large	56.5	54.7	31.5	142.7	46.8	58.0	883.9	62.9	15.0	375.7	12.4
medium	18.2	23.4	15.3	56.9	35.3	58.5	440.3	31.3	15.0	182.7	6.0
8. S. California											
large	290.8	234.5	118.9	644.2	69.3	10.0	1571.0	111.7	15.0	1421.8	46.9
medium	68.7	5°.8	33.5	162.0	39.2	8.0	434.6	30.9	15.0	402.0	13.3
small	5.6	8.9	6.6	21.1	18.7	34.5	120.8	8.6	15.0	78.5	2.6

Table B-4.—Continued

Province and Field Size[b]	ATNPV[c] (million $)	Tax (P.V.-million $)	Royalty (P.V.-million $)	Total Economic Rent (P.V.-million $)	Average Production Cost (million $)	Percent Chance of Less than Normal Profit	Reserve Discovery Size (million Mcf)	Installed Capacity (million Mcf)	Production Time Horizon (years)	Expected Natural Gas Production (million Mcf)	Expected NGL Production (million bbls.)
9. Central and Western Gulf											
large	170.6	141.3	73.1	385.0	53.7	12.0	987.7	70.2	15.0	874.1	28.8
medium	67.7	59.1	33.2	160.0	39.2	6.5	426.2	30.3	15.0	398.5	13.1
10. MAFLA											
large	269.0	217.5	108.9	595.4	58.5	34.0	1948.0	138.5	15.0	1295.4	42.7
medium	49.3	44.2	24.7	118.2	29.9	32.5	436.0	31.0	15.0	294.3	9.7
11. North Atlantic											
large	190.7	174.6	96.7	462.0	119.2	46.5	2134.0	151.8	15.0	1141.7	37.7
medium	13.8	24.8	17.3	55.9	48.1	62.5	547.0	38.5	15.3	202.4	6.7
12. Central Atlantic											
large	245.7	210.3	111.0	567.0	99.7	36.0	2062.0	146.6	15.0	1319.7	43.5
medium	32.3	36.7	23.4	92.4	48.2	42.0	479.8	34.1	15.0	278.3	9.2
13. South Atlantic											
large	106.6	87.8	45.1	239.5	31.4	58.5	1317.0	93.6	15.0	540.0	17.8
medium	27.0	25.8	14.6	67.4	20.1	58.0	415.5	29.6	15.0	174.5	5.8

[a] The following values were used for all simulations: mean price of $1.50 per Mcf of natural gas and $13.00 per barrel of natural gas liquids; and a 12 percent discount rate for all present value calculations.

[b] For each province, reservoir sizes which are uneconomic to develop are not displayed.

[c] After tax net present value.

Table B-5.--Results of Leasing System Simulation for Petroleum Using a Cash Bonus Bid Variable with a 16.67 Percent Royalty by Province and Reservoir Size[a]

Province and Field Size[b]	ATNPV[c] (million $)	Tax (P.V.-million $)	Royalty (P.V.-million $)	Total Economic Rent (million $)	Average Production Cost (million $)	Percent Chance of Less than Normal Profit	Reserve Discovery Size (million bbls.)	Installed Capacity (million bbls.)	Production Time Horizon (years)	Expected Oil Production (million bbls.)	Expected Gas Production (million Mcf)
1. Arctic Ocean											
large	83.4	104.0	72.0	259.4	179.5	66.0	221.0	26.9	9.5	72.0	42.1
2. Central Chukchi											
large	71.0	93.4	65.8	230.2	170.9	66.0	206.9	25.0	9.7	66.5	35.5
3. Bering Sea											
large	57.8	62.8	43.3	163.9	100.2	72.5	168.3	20.8	9.1	43.7	21.3
medium	6.9	24.7	18.8	50.4	63.7	72.5	80.3	8.5	13.2	20.6	10.1
4. Gulf of Alaska											
large	668.3	499.5	284.2	1452.0	263.8	46.5	560.5	69.6	9.0	280.4	176.6
medium	40.6	45.0	32.7	118.3	81.1	60.0	83.7	10.3	9.2	32.0	20.1
5. Cook Inlet											
large	218.1	193.1	118.8	530.0	191.0	30.0	184.9	23.0	9.0	122.2	52.0
medium	63.9	86.8	60.0	210.7	139.2	18.5	78.4	9.1	11.1	60.5	25.8
6. North Pacific											
large	434.5	314.8	174.1	923.4	125.8	64.5	544.4	67.6	9.0	179.8	63.3
medium	35.7	33.4	22.4	91.5	44.8	68.5	77.4	9.6	9.0	23.0	8.1
7. Santa Cruz											
large	113.1	91.8	55.0	259.9	72.8	60.5	152.8	19.0	9.0	57.0	12.1
medium	43.1	39.7	26.7	109.5	53.2	60.5	75.0	9.3	9.0	27.6	5.9
8. S. California											
large	563.5	408.9	218.8	1191.2	125.9	10.5	273.8	34.0	9.0	231.3	50.9
medium	139.3	102.6	61.1	303.0	66.5	10.0	75.4	9.4	9.0	64.4	14.2
small	15.9	21.5	14.4	51.8	36.1	10.0	17.9	2.2	9.6	15.3	3.4

Table B-5.--Continued

Province and Field Size[b]	ATNPV[c] (million $)	Tax (P.V.-million $)	Royalty (P.V.-million $)	Total Economic Rent (million $)	Average Production Cost (million $)	Percent Chance of Less than Normal Profit	Reserve Discovery Size (million bbls.)	Installed Capacity (million bbls.)	Production Time Horizon (years)	Expected Oil Production (million bbls.)	Expected Gas Production (million Mcf)
9. Central and Western Gulf											
large	506.2	366.3	193.2	1066.7	97.1	8.0	163.5	20.3	9.0	142.0	546.5
medium	215.8	155.7	87.3	458.8	67.9	4.5	71.1	8.8	9.0	64.1	246.7
small	18.2	22.9	14.5	55.6	33.6	4.5	11.9	1.5	9.2	10.7	41.1
10. MAFLA											
large	434.9	310.3	166.9	912.1	92.6	40.0	308.1	38.3	9.0	174.5	35.6
medium	86.2	64.1	38.6	188.9	44.7	40.0	71.2	8.8	9.0	40.3	8.2
small	3.3	8.5	6.2	18.0	19.8	52.0	14.3	1.7	9.7	6.5	1.3
11. North Atlantic											
large	349.8	270.2	159.1	779.1	183.0	50.0	311.4	38.7	9.0	148.4	171.0
medium	41.0	44.6	32.1	117.7	78.4	60.0	79.0	9.7	9.2	29.8	34.4
12. Central Atlantic											
large	428.9	321.1	179.1	929.1	151.5	42.5	327.3	40.7	9.0	177.6	116.2
medium	69.0	59.7	39.6	168.3	72.2	44.5	75.3	9.4	9.0	39.1	25.6
13. South Atlantic											
large	175.2	126.0	69.1	370.3	46.0	66.0	217.4	27.0	9.0	70.8	29.9
medium	48.5	37.2	22.5	108.2	27.9	64.5	69.6	8.7	9.0	23.0	9.7

[a] The following values were used for oil simulations: mean price of $16.00 per barrel of oil and $2.00 per Mcf of associated gas; and a 12 percent discount rate for all present value calculations.

[b] For each province, reservoir sizes which are uneconomic to develop are not displayed.

[c] After tax net present value.

Table B-6.--Results of Leasing System Simulation for Non-associated Natural Gas Using a Cash Bonus Bid Variable with a 16.67 Percent Royalty by Province and Field Size[a]

Province and Field Size[b]	ATNPV[c] (million $)	Tax (P.V.-million $)	Royalty (P.V.-million $)	Total Economic Rent (P.V.-million $)	Average Production Cost (million $)	Percent Chance of Less than Normal Profit	Reserve Discovery Size (million Mcf)	Installed Capacity (million Mcf)	Production Time Horizon (years)	Expected Natural Gas Production (million Mcf)	Expected NGL Production (million bbls.)
1. Arctic Ocean											
large	77.8	99.4	62.4	239.6	136.0	58.0	1333.0	94.8	15.0	559.9	18.5
2. Central Chukchi											
large	67.6	90.2	57.3	215.1	129.9	58.5	1254.0	89.1	15.0	514.1	17.0
3. Bering Sea											
large	56.4	64.4	39.6	160.4	78.0	64.0	996.8	70.9	15.0	358.8	11.8
medium	9.3	22.8	16.4	48.5	50.0	72.0	517.1	36.4	15.3	147.4	4.9
4. Gulf of Alaska											
large	548.9	455.0	234.6	1238.5	170.3	40.5	3556.0	252.9	15.0	2115.8	69.8
medium	35.6	43.1	27.8	106.5	60.8	48.5	492.4	35.0	15.0	251.1	8.3
5. Cook Inlet											
large	161.6	152.4	86.4	400.4	118.8	22.0	1002.0	71.2	15.0	786.6	25.9
medium	53.6	61.2	39.7	154.5	84.4	26.0	485.3	34.5	15.0	361.5	11.9
6. North Pacific											
large	369.6	297.3	150.4	817.3	85.8	58.5	3312.0	235.6	15.0	1374.5	45.4
medium	31.5	33.2	19.9	84.6	34.9	58.5	443.5	31.5	15.0	181.8	6.0
7. Santa Cruz											
large	84.9	76.3	41.7	202.9	47.4	56.5	870.7	61.9	15.0	378.8	12.5
medium	32.9	34.6	20.9	88.4	37.2	54.5	418.0	29.7	15.0	190.2	6.3
8. S. California											
large	395.6	314.6	155.8	866.0	69.3	10.0	1571.0	111.7	15.0	1421.8	46.9
medium	99.1	82.7	44.2	226.0	39.7	4.5	426.6	30.3	15.0	405.3	13.4
small	13.2	14.7	9.9	37.8	21.6	18.5	111.0	7.9	15.0	90.5	3.0

Table B-6.--Continued

Province and Field Size[b]	ATNPV[c] (million $)	Tax (P.V.-million $)	Royalty (P.V.-million $)	Total Economic Rent (P.V.-million $)	Average Production Cost (million $)	Percent Chance of Less than Normal Profit	Reserve Discovery Size (million Mcf)	Installed Capacity (million Mcf)	Production Time Horizon (years)	Expected Natural Gas Production (million Mcf)	Expected NGL Production (million bbls.)
9. Central and Western Gulf											
large	236.6	191.4	96.4	524.4	54.4	8.5	966.8	68.8	15.0	879.8	29.0
medium	97.8	81.8	43.8	223.4	39.8	4.0	418.4	29.8	15.0	401.7	13.3
small	5.1	8.2	6.0	19.3	16.9	34.0	82.5	5.9	15.0	54.5	1.8
10. MAFLA											
large	364.8	291.1	142.8	798.7	58.5	34.0	1948.0	138.5	15.0	1295.4	42.7
medium	71.4	61.0	32.5	164.9	30.2	32.0	431.7	30.7	15.0	295.7	9.8
small	3.9	7.1	5.2	16.2	14.9	46.5	87.5	6.2	15.0	46.8	1.5
11. North Atlantic											
large	280.1	242.8	129.1	652.0	123.3	42.5	2041.0	145.2	15.0	1163.4	38.4
medium	33.0	40.8	26.5	100.3	59.1	50.0	477.1	33.9	15.0	238.6	7.9
12. Central Atlantic											
large	345.2	286.4	146.4	778.0	100.8	34.5	2026.0	144.1	15.0	1327.0	43.8
medium	54.7	54.0	31.9	140.6	51.3	36.0	450.1	32.0	15.0	290.3	9.6
13. South Atlantic											
large	146.6	118.1	59.2	323.9	31.4	58.5	1317.0	93.6	15.0	540.0	17.8
medium	40.1	35.6	19.2	94.9	20.2	58.0	412.2	29.3	15.0	175.2	5.8

[a] The following values were used for all simulations: mean price of $2.00 per Mcf of natural gas and $16.00 per barrel of natural gas liquids; and a 12 percent discount rate for all present value calculations.

[b] For each province, reservoir sizes which are uneconomic to develop are not displayed.

[c] After tax net present value

Table B-7.--Results of Leasing System Simulation for Petroleum Using a Cash Bonus Bid Variable with a 50 Percent Capital Recovery Profit Share Plan[a]

Province and Field Size[b]	ATNPV[c] (million $)	Tax (P.V.-million $)	Profit Share (P.V.-million $)	Total Economic Rent (P.V.-million $)	Average Production Cost (million $)	Percent Chance of Less than Normal Profit	Reserve Discovery Size (million bbls.)	Installed Capacity (million bbls.)	Production Time Horizon (years)	Expected Oil Production (million bbls.)	Expected Gas Production (million Mcf)
1. Arctic Ocean											
large	6.3	44.0	54.3	104.6	146.0	72.5	250.1	28.8	11.3	64.0	37.4
2. Central Chukchi											
large	1.9	37.6	46.0	85.5	128.8	76.5	251.4	29.1	11.1	54.8	29.3
3. Bering Sea											
large	9.7	27.0	33.5	70.2	82.1	80.0	199.8	24.7	9.2	37.8	18.4
4. Gulf of Alaska											
large	272.0	219.9	383.5	875.4	266.1	46.0	552.7	68.7	9.0	281.7	177.4
medium	4.4	18.9	22.1	45.4	61.5	72.0	97.6	11.5	10.1	26.3	16.6
5. Cook Inlet											
large	73.5	87.6	126.5	287.6	179.9	36.5	196.5	24.4	9.0	117.8	50.2
medium	12.9	31.7	37.5	82.1	96.5	54.0	103.5	12.2	10.3	45.6	19.4
6. North Pacific											
large	183.6	139.7	258.4	581.7	126.7	64.5	538.6	66.9	9.0	180.4	63.5
medium	8.0	15.9	21.4	45.3	41.3	72.5	83.1	10.3	9.0	21.6	7.6
7. Santa Cruz											
large	41.6	43.2	68.5	153.3	72.3	60.5	154.1	19.1	9.0	56.7	12.1
medium	10.8	19.3	25.8	55.9	49.7	64.5	79.4	9.9	9.0	26.2	5.6
8. S. California											
large	242.1	182.2	346.7	771.0	127.5	8.0	267.9	33.3	9.0	232.6	51.2
medium	53.8	49.3	82.4	185.5	67.3	8.0	74.2	9.2	9.0	64.8	14.3
small	2.1	7.9	9.7	19.7	26.0	46.0	22.2	2.7	9.2	11.4	2.5

Table B-7.--Continued

Province and Field Size[b]	ATNPV[c] (million $)	Tax (P.V.-million $)	Profit Share (P.V.-million $)	Total Economic Rent (P.V.-million $)	Average Production Cost (million $)	Percent Chance of Less than Normal Profit	Reserve Discovery Size (million bbls.)	Installed Capacity (million bbls.)	Production Time Horizon (years)	Expected Oil Production (million bbls.)	Expected Gas Production (million Mcf)
9. Central and Western Gulf											
large	172.6	134.3	252.6	559.5	97.9	6.5	161.4	20.1	9.0	142.5	548.3
medium	68.1	59.4	103.0	230.5	68.6	2.5	70.0	8.7	9.0	64.4	247.9
small	.2	5.6	6.8	12.6	20.0	56.0	16.1	2.0	9.0	6.8	26.0
10. MAFLA											
large	187.0	138.3	265.1	590.4	93.0	40.0	306.1	38.0	9.0	174.8	35.7
medium	32.0	30.9	51.4	114.3	44.7	40.0	71.2	8.8	9.0	40.3	8.2
11. North Atlantic											
large	128.7	116.9	189.1	434.7	182.0	50.0	313.6	39.0	9.0	148.0	170.5
medium	3.7	17.8	20.8	42.3	59.1	72.0	92.0	10.9	10.1	24.4	28.1
12. Central Atlantic											
large	173.7	141.1	250.2	564.4	153.4	40.5	320.9	39.9	9.0	178.7	116.9
medium	18.7	27.5	37.4	83.6	65.3	52.5	81.9	10.2	9.0	36.3	23.7
13. South Atlantic											
large	72.2	56.1	105.2	233.5	46.3	64.5	215.0	26.7	9.0	71.0	30.0
medium	16.5	17.7	29.4	63.6	28.0	64.5	68.9	8.6	9.0	23.1	9.7

[a] The following values were used for all simulations: mean price of $11.00 per barrel of oil and $.60 per Mcf of associated gas; and a 12 percent discount rate for all present value calculations.

[b] For each province, reservoir sizes which are uneconomic to develop are not displayed.

[c] After tax net present value.

Table B-8.--Results of Leasing System Simulation for Non-associated Natural Gas Using a Cash Bonus Bid Variable with a 50 Percent Capital Recovery Plan[a]

Province and Field Size[b]	ATNPV[c] (million $)	Tax (P.V.-million $)	Profit Share (P.V.-million $)	Total Economic Rent (P.V.-million $)	Average Production Cost (million $)	Percent Chance of Less than Normal Profit	Reserve Discovery Size (million Mcf)	Installed Capacity (million Mcf)	Production Time Horizon (years)	Expected Natural Gas Production (million Mcf)	Expected NGL Production (million bbls.)
1. Arctic Ocean					No Development						
2. Central Chuckchi					No Development						
3. Bering Sea					No Development						
4. Gulf of Alaska											
large	88.1	100.8	165.4	354.3	159.2	48.0	3918.0	278.7	15.0	2037.4	67.2
5. Cook Inlet											
large	8.4	24.5	34.6	67.5	65.5	68.0	1668.0	114.5	16.2	533.8	17.6
6. North Pacific											
large	67.1	68.5	119.7	255.3	85.3	58.5	3343.0	237.8	15.0	1370.6	45.2
7. Santa Cruz											
large	5.7	14.9	22.0	42.6	37.1	72.0	1130.0	80.3	15.0	316.4	10.4
8. S. California											
large	78.3	72.5	133.2	284.0	68.5	12.0	1605.0	114.1	15.0	1412.4	46.6
medium	13.0	17.4	27.5	57.9	35.0	24.0	489.0	34.8	15.0	371.6	12.3
9. Central and Western Gulf											
large	42.7	43.1	76.2	162.0	51.7	18.0	1044.0	74.2	15.0	856.1	28.2
medium	12.7	17.1	27.0	56.8	34.8	24.0	482.2	34.3	15.0	366.5	12.1
10. MAFLA											
large	72.9	67.1	125.2	265.2	58.3	34.0	1959.0	139.3	15.0	1292.9	42.7
medium	8.3	12.8	20.3	41.4	27.0	44.0	488.1	34.7	15.0	273.3	9.0

Table B-8.--Continued

Province and Field Size[b]	ATNPV[c] (million $)	Tax (P.V.-million $)	Profit Share (P.V.-million $)	Total Economic Rent (P.V.-million $)	Average Production Cost (million $)	Percent Chance of Less than Normal Profit	Reserve Discovery Size (million Mcf)	Installed Capacity (million Mcf)	Production Time Horizon (years)	Expected Natural Gas Production (million Mcf)	Expected NGL Production (million bbls.)
11. North Atlantic											
large	33.5	49.9	76.3	159.7	102.0	58.5	2520.0	179.1	15.0	1033.2	34.1
12. Central Atlantic											
large	56.5	63.8	106.4	226.7	94.5	42.5	2227.0	158.4	15.0	1280.5	42.3
13. South Atlantic											
large	26.5	27.3	49.2	103.0	31.4	58.5	1317.0	93.6	15.0	540.0	17.8
medium	2.8	7.4	11.6	21.8	18.4	64.5	462.1	32.9	15.0	161.7	5.3

[a] The following values were used for all simulations: mean price of $.60 per Mcf of natural gas and $11.00 per barrel of natural gas liquids; and a 12 percent discount rate for all present value calculations.

[b] For each province, reservoir sizes which are uneconomic to develop are not displayed.

[c] After tax net present value.

Table B-9.--Results of Leasing System Simulation for Petroleum Using a Cash Bonus Bid Variable with a 50 Percent Capital Recovery Profit Share Plan[a]

Province and Field Size[b]	ATNPV[c] (million $)	Tax (P.V.-million $)	Profit Share (P.V.-million $)	Total Economic Rent (P.V.-million $)	Average Production Cost (million $)	Percent Chance of Less than Normal Profit	Reserve Discovery Size (million $)	Installed Capacity (million bbls.)	Production Time Horizon (years)	Expected Oil Production (million bbls.)	Expected Gas Production (million Mcf)
1. Arctic Ocean											
large	29.9	61.3	80.0	171.2	171.5	68.5	235.0	29.1	9.0	68.8	40.1
2. Central Chukchi											
large	24.1	55.9	71.5	151.5	163.5	70.0	219.6	27.1	9.1	63.2	36.9
3. Bering Sea											
large	23.8	37.7	50.5	112.0	95.0	74.5	117.5	23.1	9.0	41.9	22.4
4. Gulf of Alaska											
large	350.7	272.1	491.2	1114.0	269.6	44.5	541.5	67.3	9.0	283.6	138.1
medium	16.0	27.6	34.4	78.0	76.6	62.5	87.1	10.8	9.1	30.4	19.2
5. Cook Inlet											
large	113.7	114.9	178.4	407.0	191.2	30.0	184.9	23.0	9.0	122.2	77.0
medium	30.2	44.7	56.1	131.0	118.4	42.0	93.7	11.6	9.1	51.3	21.9
6. North Pacific											
large	232.9	172.9	328.0	733.8	126.7	64.5	538.6	66.9	9.0	180.4	76.9
medium	16.0	20.3	29.3	65.6	44.3	68.5	78.1	9.7	9.0	22.8	8.0
7. Santa Cruz											
large	60.1	54.1	90.3	204.5	75.2	58.0	146.4	18.2	9.0	58.0	20.4
medium	20.0	24.2	34.6	78.8	52.8	62.0	75.5	9.4	9.0	27.4	5.9
8. S. California											
large	300.8	220.0	425.9	946.7	127.5	8.0	267.9	33.3	9.0	232.6	49.8
medium	73.9	58.8	102.4	235.1	67.5	6.5	74.0	9.2	9.0	64.9	14.3
small	5.5	11.7	15.6	32.8	31.7	28.0	19.8	2.5	9.1	13.6	3.0

Table B-9.--Continued

Province and Field Size[b]	ATNPV[c] (million $)	Tax (P.V.- million $)	Profit Share (P.V.- million $)	Total Economic Rent (P.V.- million $)	Average Production Cost (million $)	Percent Chance of Less than Normal Profit	Reserve Discovery Size (million $)	Installed Capacity (million bbls.)	Production Time Horizon (years)	Expected Oil Production (million bbls.)	Expected Gas Production (million Mcf)
9. Central and Western Gulf											
large	177.1	132.8	249.9	559.8	97.4	8.0	162.8	20.2	9.0	142.2	31.3
medium	111.2	84.9	156.4	352.5	69.2	0.5	69.2	8.6	9.0	64.7	248.9
small	6.6	12.1	16.9	35.6	30.0	18.5	12.9	1.6	9.0	9.9	38.1
10. MAFLA											
large	338.8	241.2	479.9	1059.9	94.2	36.5	294.1	36.5	9.0	176.3	678.2
medium	44.7	36.9	63.9	145.5	45.0	40.0	70.8	8.8	9.0	40.4	8.2
11. North Atlantic											
large	158.3	135.4	227.1	520.8	183.0	50.0	311.4	38.7	9.0	148.4	30.3
medium	16.5	27.6	34.5	78.6	76.1	62.0	80.7	10.0	9.0	28.9	33.3
12. Central Atlantic											
large	242.2	186.8	345.4	774.4	154.5	40.0	316.8	39.4	9.0	179.4	206.7
medium	33.7	36.0	52.6	122.3	71.8	46.0	75.6	9.4	9.0	38.9	25.4
13. South Atlantic											
large	94.9	70.4	135.3	300.6	46.3	64.5	215.0	26.7	9.0	71.0	46.4
medium	24.2	21.4	37.1	82.7	28.0	64.5	68.9	8.6	9.0	23.1	9.7

[a] The following values were used for all simulations: mean price of $13.00 per barrel of oil and $1.50 per Mcf of associated gas; and a 12 percent discount rate for all present value calculations.

[b] For each province, reservoir sizes which are uneconomic to develop are not displayed.

[c] After tax net present value.

Table B-10.--Results of Leasing System Simulation for Non-associated Natural Gas Using a Cash Bonus Bid Variable with a 50 Percent Capital Recovery Plan[a]

Province and Field Size[b]	ATNPV[c] (million $)	Tax (P.V.-million $)	Profit Share (P.V.-million $)	Total Economic Rent (P.V.-million $)	Average Production Cost (million $)	Percent Chance of Less than Normal Profit	Reserve Discovery Size (million Mcf)	Installed Capacity (million Mcf)	Production Time Horizon (years)	Expected Natural Gas Production (million Mcf)	Expected NGL Production (million bbls.)
1. Arctic Ocean											
large	18.1	47.8	72.2	138.1	113.5	68.5	1569.0	111.4	15.1	486.4	16.0
2. Central Chukchi											
large	14.1	43.8	65.4	123.3	109.9	68.5	1456.0	103.1	15.2	451.4	14.9
3. Bering Sea											
large	17.0	32.5	49.1	98.6	70.0	70.0	1104.0	78.5	15.0	331.2	10.9
4. Gulf of Alaska											
large	252.7	228.5	425.9	907.1	171.7	40.0	3511.0	249.7	15.0	2124.2	70.1
medium	9.3	21.5	31.0	61.8	52.4	60.0	549.6	39.1	15.0	222.6	7.3
5. Cook Inlet											
large	67.3	78.0	127.7	273.0	113.9	26.5	1050.0	74.7	15.0	766.5	25.3
medium	16.2	30.1	43.3	89.6	70.5	42.5	552.9	39.3	15.0	315.2	10.4
6. North Pacific											
large	172.3	148.5	286.0	606.8	87.0	56.5	3218.0	228.9	15.0	138.4	45.7
medium	10.6	17.3	27.2	55.1	33.8	62.0	459.9	32.7	15.0	177.1	5.8
7. Santa Cruz											
large	36.2	39.3	68.3	143.8	47.7	56.0	863.0	61.4	15.0	379.2	12.5
medium	11.3	18.1	28.2	57.6	36.1	56.5	431.9	30.7	15.0	185.7	6.1
8. S. California											
large	187.3	155.6	306.2	649.1	70.7	6.0	1517.0	107.9	15.0	1433.6	47.3
medium	44.9	41.8	76.3	163.0	39.8	4.5	426.6	30.3	15.0	405.3	13.4
small	3.3	7.1	11.0	21.4	19.0	34.0	120.6	8.6	15.0	79.6	2.6

Table B-10.--Continued

Province and Field Size[b]	ATNPV[c] (million $)	Tax (P.V.-million $)	Profit Share (P.V.-million $)	Total Economic Rent (P.V.-million $)	Average Production Cost (million $)	Percent Chance of Less than Normal Profit	Reserve Discovery Size (million Mcf)	Installed Capacity (million Mcf)	Production Time Horizon (years)	Expected Natural Gas Production (million Mcf)	Expected NGL Production (million bbls.)
9. Central and Western Gulf											
large	110.2	94.9	183.2	388.3	54.9	8.0	954.8	67.9	15.0	883.2	29.1
medium	44.3	41.3	75.4	161.0	39.8	4.0	418.4	29.8	15.0	401.7	13.3
10. MAFLA											
large	171.6	143.0	283.7	598.3	59.2	32.0	1901.0	135.2	15.0	1302.2	43.0
medium	31.6	30.8	56.2	118.6	30.2	32.0	431.7	307.0	15.0	295.7	9.8
11. North Atlantic											
large	125.7	123.8	220.1	469.6	124.4	42.0	2015.0	143.3	15.0	1168.7	38.6
medium	7.9	20.0	28.8	56.7	49.5	62.0	544.1	38.6	15.0	206.8	6.8
12. Central Atlantic											
large	158.8	143.3	269.0	571.1	101.6	34.0	2003.0	142.4	15.0	1332.0	43.9
medium	21.0	27.8	44.2	93.0	49.0	40.5	472.8	33.6	15.0	281.3	9.3
13. South Atlantic											
large	67.6	58.5	114.4	240.5	31.7	58.0	1290.0	91.8	15.0	541.8	17.9
medium	16.7	18.0	32.8	67.5	20.3	58.0	412.2	29.3	15.0	175.2	5.8

[a] The following values were used for all simulations: mean price of $1.50 per Mcf of natural gas and $13.00 per barrel of natural gas liquids; and a 12 percent discount rate for all present value calculations.

[b] For each province, reservoir sizes which are uneconomic to develop are not displayed.

[c] After tax net present value.

Table B-11.--Results of Leasing System Simulation for Petroleum Using a Cash Bonus Bid Variable with a 50 Percent Capital Recovery Profit Share Plan[a]

Province and Field Size[b]	ATNPV[c] (million $)	Tax (P.V.-million $)	Profit Share (P.V.-million $)	Total Economic Rent (P.V.-million $)	Average Production Cost (million $)	Percent Chance of Less than Normal Profit	Reserve Discovery Size (million bbls.)	Installed Capacity (million bbls.)	Production Time Horizon (years)	Expected Oil Production (million bbls.)	Expected Gas Production (million Mcf)
1. Arctic Ocean											
large	63.6	85.7	120.8	270.1	197.7	60.5	206.6	25.7	9.0	76.1	44.4
2. Central Chukchi											
large	52.3	75.9	106.0	234.2	180.5	64.5	201.9	25.1	9.0	67.7	36.1
3. Bering Sea											
large	44.3	50.8	73.5	168.6	106.3	70.0	160.4	19.9	9.0	45.4	22.1
medium	3.3	22.7	27.1	53.1	71.5	72.0	78.3	9.1	10.7	21.1	10.3
4. Gulf of Alaska											
large	466.2	349.3	652.3	1467.8	270.7	44.0	537.7	66.8	9.0	284.2	179.0
medium	32.5	36.9	50.6	120.0	83.9	58.0	82.4	10.2	9.0	32.7	20.6
5. Cook Inlet											
large	160.0	143.3	234.6	537.9	199.0	24.5	176.6	21.9	9.0	125.0	53.3
medium	56.5	60.1	82.5	199.1	131.6	32.5	87.5	10.9	9.0	55.3	23.6
6. North Pacific											
large	297.1	215.0	416.0	928.1	127.3	64.0	532.5	66.2	9.0	180.9	63.7
medium	27.5	25.8	40.1	93.4	46.6	66.5	75.1	9.3	9.0	23.7	8.4
7. Santa Cruz											
large	82.1	66.5	116.0	264.6	75.7	58.0	145.2	18.0	9.0	58.2	12.5
medium	33.9	30.9	47.4	112.2	55.8	58.0	72.1	9.0	9.0	28.6	6.1
8. S. California											
large	385.5	273.8	538.6	1197.9	127.7	8.0	266.7	33.1	9.0	232.8	51.2
medium	102.3	72.0	130.3	304.6	67.3	8.0	74.3	9.2	9.0	64.8	14.3
small	10.8	16.9	24.4	52.1	37.1	8.5	17.8	2.2	9.0	15.3	3.4

Table B-11.--Continued

Province and Field Size[b]	ATNPV[c] (million $)	Tax (P.V.-million $)	Profit Share (P.V.-million $)	Total Economic Rent (P.V.-million $)	Average Production Cost (million $)	Percent Chance of Less than Normal Profit	Reserve Discovery Size (million bbls.)	Installed Capacity (million bbls.)	Production Time Horizon (years)	Expected Oil Production (million bbls.)	Expected Gas Production (million Mcf)
9. Central and Western Gulf											
large	343.8	244.7	483.7	1072.0	98.8	4.5	158.7	19.7	9.0	143.0	550.4
medium	152.9	106.9	202.6	462.4	69.2	0.5	69.2	8.6	9.0	64.7	248.9
small	12.2	17.3	26.4	55.9	33.6	2.5	11.7	1.5	9.0	10.7	41.4
10. MAFLA											
large	296.5	208.1	411.1	915.7	93.7	38.5	302.1	37.5	9.0	175.3	35.8
medium	62.9	45.1	81.3	189.3	45.0	40.0	70.8	8.8	9.0	40.4	8.2
small	1.8	7.2	9.6	18.6	21.0	50.0	14.0	1.7	9.0	6.7	1.4
11. North Atlantic											
large	247.9	193.6	346.6	788.1	188.3	46.5	298.3	37.1	9.0	150.7	173.6
medium	32.6	36.4	50.4	119.4	81.0	58.5	77.6	9.6	9.0	30.4	35.0
12. Central Atlantic											
large	297.9	221.8	418.4	938.1	155.1	40.0	314.8	39.1	9.0	179.7	117.6
medium	52.9	45.3	71.5	169.7	73.5	44.0	74.2	9.2	9.0	39.6	25.9
13. South Atlantic											
large	119.7	85.3	166.5	371.5	46.3	64.5	215.0	26.7	9.0	71.0	30.0
medium	35.0	26.2	47.3	108.5	28.0	64.5	68.9	8.6	9.0	23.1	9.7

[a] The following values were used for all simulations: mean price of $16.00 per barrel of oil and $2.00 per Mcf of associated gas; and a 12 percent discount rate for all present value calculations.

[b] For each province, reservoir sizes which are uneconomic to develop are not displayed.

[c] After tax net present value.

Table B-12.--Results of Leasing System Simulation for Non-associated Natural Gas Using a Cash Bonus Bid Variable with a 50 Percent Capital Recovery Plan[a]

Province and Field Size[b]	ATNPV[c] (million $)	Tax (P.V.-million $)	Profit Share (P.V.-million $)	Total Economic Rent (P.V.-million $)	Average Production Cost (million $)	Percent Chance of Less than Normal Profit	Reserve Discovery size (million Mcf)	Installed Capacity (million Mcf)	Production Time Horizon (years)	Expected Natural Gas Production (million Mcf)	Expected NGL Production (million bbls.)
1. Arctic Ocean											
large	48.9	75.4	119.9	244.2	141.5	54.5	1281.0	91.1	15.0	576.5	19.0
2. Central Chukchi											
large	41.1	68.0	107.5	216.6	132.0	58.0	1239.0	88.1	15.0	520.4	17.2
3. Bering Sea											
large	36.0	48.4	77.9	162.3	79.9	62.5	973.7	69.3	15.0	365.1	12.0
medium	4.1	18.6	26.3	49.0	51.1	70.5	515.4	36.6	15.0	149.5	4.9
4. Gulf of Alaska											
large	354.1	306.0	587.4	1247.5	173.5	38.0	3441.0	244.7	15.0	2133.4	70.4
medium	23.1	33.3	51.5	107.9	62.4	46.5	482.5	34.3	15.0	255.7	8.4
5. Cook Inlet											
large	106.1	108.7	188.4	403.2	121.0	18.5	980.8	69.8	15.0	794.4	26.2
medium	36.1	47.4	73.0	156.5	86.7	22.5	475.7	33.8	15.0	368.7	12.2
6. North Pacific											
large	237.6	197.8	389.0	824.4	87.5	56.5	3189.0	226.8	15.0	1387.2	45.8
medium	19.6	24.3	40.9	84.8	35.2	58.5	441.0	31.4	15.0	183.0	6.0
7. Santa Cruz											
large	54.8	53.4	97.3	205.5	48.8	54.0	836.9	59.5	15.0	385.0	12.7
medium	21.0	25.6	42.7	89.3	38.0	52.5	410.3	29.2	15.0	192.8	6.7
8. S. California											
large	254.0	206.6	412.9	873.5	70.9	4.5	1511.0	107.5	15.0	1435.5	47.4
medium	64.1	56.3	106.5	226.9	40.2	2.5	420.3	29.9	15.0	407.7	13.5
small	8.7	11.1	18.4	38.2	22.0	16.5	109.7	7.8	15.0	91.6	3.0

Table B-12.--Continued

Province and Field Size[b]	ATNPV[c] (million $)	Tax (P.V.-million $)	Profit Share (P.V.-million $)	Total Economic Rent (P.V.-million)	Average Production Cost (million $)	Percent Chance of Less than Normal Profit	Reserve Discovery Size (million Mcf)	Installed Capacity (million Mcf)	Production Time Horizon (years)	Expected Natural Gas Production (million Mcf)	Expected NGL Production (million bbls.)
9. Central and Western Gulf											
large	152.0	126.7	249.6	528.3	55.5	4.5	934.4	66.5	15.0	887.7	29.3
medium	63.3	55.8	105.3	224.4	40.3	2.0	412.2	29.3	15.0	404.0	13.3
small	2.9	6.3	10.1	19.3	17.0	34.0	82.9	5.9	15.0	54.7	1.8
10. MAFLA											
large	232.4	189.8	381.5	803.7	59.4	30.5	1890.0	134.4	15.0	1304.1	43.0
medium	45.5	41.4	78.4	165.3	30.4	30.5	427.0	30.4	15.0	296.8	9.8
small	1.9	5.5	8.8	16.2	14.9	46.5	87.5	6.2	15.0	46.8	1.5
11. North Atlantic											
large	181.5	166.8	309.2	657.5	125.9	40.5	1975.0	140.5	15.0	1175.1	38.8
medium	21.3	31.6	48.7	101.6	60.8	48.0	468.0	33.3	15.0	243.4	8.0
12. Central Atlantic											
large	221.8	191.6	369.7	783.1	102.6	32.0	1966.0	139.8	15.0	1336.9	44.1
medium	35.7	39.4	66.6	141.7	52.3	34.0	442.1	31.4	15.0	294.0	9.7
13. South Atlantic											
large	93.1	77.9	154.9	325.9	31.9	58.0	1278.0	90.9	15.0	543.2	17.9
medium	24.8	24.2	45.8	94.8	20.3	58.0	412.2	29.3	15.0	175.2	5.8

[a] The following values were used for all simulations: mean price of $2.00 per Mcf of natural gas and $16.00 per barrel of natural gas liquids; and a 12 percent discount rate for all present value calculations.

[b] For each province, reservoir sizes which are uneconomic to develop are not displayed.

[c] After tax net present value.

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