FINAL REPORT

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Competition and Performance in OCS Oil and Gas Lease Sales and Lease Development, 1954-1969

Principal Investigators:

Walter J. Mead
Philip E. Sorensen

Other Investigators:

Russell O. Jones
Asbjorn Moseidjord

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Government Technical Officer:

Mrs. Holly Tomlinson
U.S. Geological Survey
Conservation Division
12201 Sunrise Valley Drive
Reston, Virginia 22092

347149

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Preface

We wish to acknowledge the generous assistance provided by numerous individuals employed in the U.S. oil industry who helped us to obtain necessary data relating to offshore exploration and drilling costs and who made valuable criticisms of earlier drafts of this report. We also thank the many federal and state government officials who assisted us in developing our data base, particularly the staff of the USGS Conservation Division office in Metarie, Louisiana. Of the many academic economists who commented on our work in earlier stages, we owe special thanks to Dr. James L. Smith. Most importantly, we acknowledge the years of patient and constructive collaboration in this research by our Government Technical Officers, John Lohrenz and Holly Tomlinson.

It goes without saying that none of the individuals who helped us in the development of our research is responsible for any errors in this report. The conclusions reported here are those of the authors and are not necessarily endorsed by any of the individuals or organizations mentioned above, nor by the U.S. Geological Survey.

EXECUTIVE SUMMARY

The central policy-related research questions addressed by this study are the following:

1. Under the cash bonus bidding system, has the federal government received fair market value for its OCS leases?

2. Is the OCS lease sale market effectively competitive?

3. Have large firms obtained leases at less than fair market value?

4. Is there evidence that joint bidding has restrained competition?

5. Is there evidence that firms or particular classes of firms have not developed OCS leases in a diligent manner?

In order to answer these questions, we have analyzed 1,223 leases issued in 17 OCS lease sales in the Gulf of Mexico held over the years 1954-1969. Our initial findings indicated that the early OCS leases yielded very low returns to the lessees. In an attempt to explain that result, we also analyzed 271 "Section 6" leases issued by the State of Louisiana in the years 1945-1948. Thus, our total data base consisted of 1,494 leases issued over a 25 year period with an accurate record of production through the year 1978.

Part I, concerned with the OCS leases only, shows that 62% of all leases issued were abandoned without production. Another 15% were productive, but unprofitable. Only 23% were productive and profitable.

For all 1,223 leases, the average Internal Rate of Return (IRR) was 11.43% before taxes.* This return is far below the average return (1954-76) for all U.S. manufacturing corporations: 19.81% before taxes. If a 20% before tax rate of return is assumed to be a normal yield for investments having risks similar to oil and gas lease investment, we find that the federal government's share in the net economic rent yielded by these leases is 244%. This means that the federal government will receive almost 2 1/2 times as much net revenue from these leases as would have been paid in a competitive lease market. This evidence clearly supports the conclusion that the government received more than fair market value for these leases issued under the cash bonus bidding system. The low IRR, as a measure of competitive performance, indicates that the lease sale market is intensely competitive.

The IRR estimate includes projected production and prices from 1979 through economic exhaustion of each lease, not later than the year 2010. Sensitivity analyses were made of assumed production decline rates and future prices for both gas and liquids. If production declines at an annual rate of 20% instead of the 15% rate which was assumed, the IRR would be 10.51%

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*IRR estimates are on a before corporate income tax basis, but price forecasts for 1980 and beyond are net of President Carter's proposed windfall profits tax on oil production.

A 10% decline rate would yield a 12.63% IRR. If future prices are 10% below those assumed in our standard scenario, the IRR would be 11.04%. On the other hand, if future prices are as much as 50% above our scenario, the IRR would be 12.96%. Thus, even with more favorable decline rates or greater price increases than assumed, the IRR would still be well below normal yields on capital.

There is some evidence that, in accord with economic theory, IRR's on lease sales tend over time toward a normal yield on capital. The 1954-55 wildcat leases returned only 7.84% to lessees. This IRR was below the average of 10.57% for all wildcat leases. Similarly, the first drainage lease yielded 7.60% whereas the average for all drainage leases was 15.9%. The fact that drainage leases yielded significantly higher returns than wildcat leases is contrary to expectations based on economic theory. This result may reflect risk preference (in the hope of finding another Prudhoe Bay) or the fact that buyers of wildcat tracts gain important advantages over rivals in the event that nearby acreage is sold in later drainage sales.

When oil companies are arrayed and classified by their worldwide sales, we find that the Big-8 firms bought 59.3% of the leases (with jointly won sales allocated in proportion to joint-bid shares) and earned a 10.91% return on their investment. This is 5% below the average of 11.43%. The Big-9-20 firms bought 24.4% of all leases and their IRR was 12.21%, 7% above the average. All other firms (small firms) bought 16.3% of all leases and earned an 11.90% return, 4% above the average. These findings do not support a frequently voiced allegation that large firms obtain oil and gas leases on the OCS at less than fair market value.

We find that Big-8 firms buy significantly more solo than joint bid leases relative to all other bidders. This finding is based on sales which occurred prior to the 1975 limitation on joint bidding among large firms. The Big-20 firms won significantly more drainage than wildcat leases, relative to all other bidders. However, there is no significant relationship between firm size, on one hand, and sales classified on the basis of bonus size classes, on the other hand. Also, no meaningful generalizations can be made relating firm size to average number of bidders competing for each lease

There is evidence that average bonus payments correspond with lease productivity. All three firm size classes show their highest average bonus payments for leases that turn out to be both productive and profitable, their lowest bonus payments for dry leases, and intermediate bonus payments for leases that are productive but unprofitable. There is no evidence that large firms are more or less successful than small firms in winning productive relative to unproductive leases.

Economic theory would suggest that joint bidding would occur more frequently for increasingly expensive (higher bonus bid) leases. The evidence supports this hypothesis. However, the anti-competitive hypothesis which asserts that joint bidding reduces the number of bidders is not supported by the evidence. We find that one and two bidder situations are significantly related to the use of solo bidding, precisely the opposite of the anti-competitive hypothesis. We find no significant difference in the use of joint bidding in wildcat relative to drainage sales.

Finally, we tested for presence of trends in the bidding results.

We find no significant trend in dry relative to productive leases, for either wildcat or drainage lease sales. The average percent dry is 64.77% for wildcat, and 40.29% for drainage leases. These averages are significantly different at the 95% confidence level. There is no significant trend in the average number of bidders by lease sale for wildcat or drainage lease sales, and the mean values do not differ significantly between these sale types. The average number of bidders for all 1,223 leases is 3.33. We find no significant trend in the ratio of solo to joint winning bids and the average solo/joint ratio for wildcat leases does not differ significantly from that of drainage sales.

We discovered some evidence explaining the very low IRR earned on the first 184 Louisiana OCS leases (7.84%) in the record of the 271 "Section 6" leases originally issued by the State of Louisiana over the years 1945-48. These leases yielded an internal rate of return amounting to 18.98% <u>before taxes</u>. The prospective success of the Section 6 leases was one of the factors leading to increased competition in subsequent OCS lease sales beginning in 1954. A sharp increase in the number of bidders occurred immediately. The Section 6 leases had received an average of 1.4 bids per lease issued. More than twice as many bids were received on average for the 1954-55 Louisiana OCS leases -- 3.68 bids per lease issued. This increased competition brought higher average bonus payments and lower IRR's. The importance of the higher level of competition for leases is shown in the fact that, if bonus payments are omitted from the calculation, IRR's are almost identical between the Section 6 leases and the 1223 OCS leases issued from 1954 through 1969: 19.50% compared to 19.10%.

The analysis conducted in Parts I and II of this report is primarily concerned with the computed internal rates of return for various categories of leases. In Part III, emphasis shifts to an analysis of the observed variation in high bids, using multiple regression techniques. Several important policy issues--the competitive importance of number of bidders competing for a given tract, the significance of firm size, the competitive impact of joint bidding, and the rationality and efficiency of the cash bonus bidding system--are addressed in this part of the report.

Regression analysis establishes that the number of bidders is a very important determinant of the observed high bid (both measured in logarithms). This finding is consistent with both economic theory and other empirical studies showing that the bid price increases with the number of bidders competing for the asset.

Our measures of perceived quality of the tract, represented by actual production from each lease through the year 1978, the number of wells drilled within 24 months of the lease sale date, and the number of acres in the tract, all showed positive and significant impacts on high bid. All of these quality variables were measured in log form. Special interest is attached to the first two of these quality variables. The fact that high bid is positively and significantly related to the actual record of production supports other evidence given in Part I that cash bonus bidding is rational. The fact that the number of wells drilled within 24 months of sale date is positively and significantly correlated with high bid indicates that lease winners move quickly to develop leases perceived as high quality and for which they make relatively high bonus payments.

Tracts having high costs should be valued at lower bid prices. This hypothesis is supported by the significant negative relationship of high bid to water depth in log form.

Only in the case of drainage lease sales was a relationship between the firm size class of the high bidder and the high bid supported by the analysis. Alleged anti-competitive barriers to entry due to "front end" payments required by cash bonus bidding, or collusive market power allegations against large firms, were not generally supported. These regression findings are consistent with the IRR conclusions in Part I indicating that the lease market is competitive and there is no systematic bias favoring large firms.

Joint winning bids are significantly higher than solo winning bids, but only in drainage sales where the winning bidder includes a Big-8 firm. The allegation that joint bidding leads to sales at less than fair market value is not supported by the record. Drainage leases have significantly higher winning bids than wildcat leases. This is consistent with the fact that drainage leases have both higher expected value and lower risk than wildcat leases.

Finally, we find several significant differences in the average level of high bids for the 17 lease sales in our study. These differences reflect the expectations of bidders, current and proposed government regulations, and economic conditions in general, which vary from lease sale to lease sale.

The regression analyses with high bid as the dependent variable indicated a high degree of consistency with hypotheses derived from economic theory. The regression results support the IRR findings that the lease sale market is competitive. The explanatory power of three separate models from which the findings reported above were developed is reasonably high. These models individually explain between 67% and 71% of the observed variation in high bids.

Part IV of our report addresses the question of expeditious development of OCS leases. Our findings derive from a separate set of regressions which attempt to explain (1) speed of exploratory drilling, (2) speed to first production of oil and gas, and (3) speed to maximum production of oil and gas. We find that Big-8 firms, solo bidders, and lessees of drainage leases drill significantly more exploratory wells than non-Big-8, joint, or wildcat lessees. Big-8 firms are also significantly faster in developing first oil production than non-Big-8 firms. But tests of speed to maximum oil production, speed to first gas production, and speed to maximum gas production show that firm size distinctions and the solo/joint bidder distinction make no significant difference. The only pervasive distinction is shown by drainage leases, which are found to be developed faster than wildcat leases on the basis of all of our tests of expeditious development. Our findings do not support the contention that large firms have sought to delay drilling or production on OCS leases in the hope of achieving monopoly gains. Indeed, in those cases where firm size is shown to have a significant effect on diligence, Big-8 firms have exceeded other firms in speed of development of leases.

SUMMARY TABLE

FEDERAL GOVERNMENT SHARE OF NET ECONOMIC RENT,
17 OCS LEASE SALES (1223 LEASES) 1954-1969

	Discount Rate				
	0%	6%	10%	15%	20%
Present Value of Net Economic Rent ($M)[1]	29,989,241	10,696,009	5,807,501	2,813,101	1,330,963
Present Value of Payments to the Federal Government -- Bonus, Rent and Royalties ($M)	10,459,922	5,641,523	4,440,030	3,670,298	3,250,728
Federal Government Share (%)	34.9	52.7	76.5	130.5	244.2

[1]Gross revenues minus exploration and production costs (including forecasted future revenues and costs through 2010) discounted to date of each lease sale, in aggregate.

INTRODUCTION

The oil and gas resources of the Outer Continental Shelf represent one of America's largest publicly-owned assets. Through 1978, OCS oil and gas leases had yielded $40.5 billion in gross production value and produced over $28.3 billion in direct revenue to the federal government.[1]

Policies and procedures for managing the oil and gas resources of the OCS were established by Congress in the Outer Continental Shelf Lands Act of 1953. The Department of Interior was given the central responsibility for carrying out this management role in the 1953 Act; this responsibility has been re-established in the 1978 Amendments to the OCS Lands Act. As stated in the 1978 legislation, the goals of OCS management are to:

> ...preserve, protect and develop oil and natural gas resources in a manner which is consistent with the need (A) to make such resources available to meet the Nation's energy needs as rapidly as possible... (C) to insure the public a fair and equitable return on the resources of the Outer Continental Shelf, and (D) to preserve and maintain free enterprise competition.[2]

As part of its continuing effort to monitor the effectiveness of federal policies relating to OCS oil and gas resources, the Conservation Division of U.S. Geological Survey, Department of Interior, has sponsored the research which is the basis for the present report. The objectives of the research have been to determine the extent to which the historical policies of OCS management have resulted in achievement of the goals set forth by Congress in the section quoted above.

Overview of the Report

This report summarizes the findings of the largest empirical study of

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[1] USGS, Outer Continental Shelf Statistics, June 1979, p. 54.

[2] PL 95-372, Sec. 102.

competition and performance in OCS leasing and development to date. This work combines the most up-to-date analysis of historical revenues and costs of OCS development, plus projected future revenues and costs. The data set comprises the first 17 OCS lease sales offshore from Louisiana, Texas, and Florida taking place over the years 1954-1969, a total of 1223 leases. To provide additional perspective on the basic research questions, a special study of the profitability of 271 so-called "Section Six" leases issued over the years 1945-1948 has been conducted. These leases were originally issued by the State of Louisiana but were subsequently taken over by the federal government after the lands involved were determined to be in the federal domain. In addition to studies of profitability, this report investigates the question of expeditious development, defined as early or speedy drilling and production from leases.

This is the second major report of findings from this research. The first, an Interim Report dated January 31, 1979, contained a set of findings based upon historical revenues and costs for these 1223 leases over the period through 1976. The Interim Report was reviewed by numerous authorities in the federal government and in the oil industry. Important suggestions for revision and reformulation of the data and analyses were made and accepted as a result of this review process. The fundamental changes incorporated in this report, as compared to the Interim Report, are the following:

1. The historical record of lease-specific production and revenue now extends from 1954 through 1978 (previously through 1976).

2. Future price projections are based upon lease specific prices of oil, gas, and other products in 1978 (as compared to 1976 in the Interim Report).

3. Costs of lease abandonment, including dismantling platforms and removing sea-floor obstructions, are now included in the cost algorithm for all leases.

4. New forecasts for future oil and gas prices have been developed and integrated into the analysis. These price forecasts are based upon changes in federal natural gas price regulation implemented in the Natural Gas Policy Act of 1978 and expected changes in crude oil prices and taxes following from phased deregulation of various categories of crude oil together with windfall profits taxes on oil production to be implemented in 1980.

5. A correction in the algorithm used to identify the number of dry wells on each lease has been implemented. This correction adjusts the number of productive wells to conform to the historical experience of the industry and to USGS records of the number of producing wells in various years.

Many additional, minor corrections of the data base have been made in the process of writing this Final Report, but their significance in relation to the overall findings is small.

This analysis relies upon three major data bases developed and maintained by USGS - Conservation Division. These are the "Lease Production and Revenue" (LPR-5, LPR-10 and LPR-19) data bases available on computer tapes of the same names. The LPR-5 tape contains lease bidding information including the names of bidders and the amounts of all bids received on each lease. The LPR-10 tape contains production, royalty, and rental data for each lease through 1978. The LPR-19 tape combines all data from the first two tapes and adds data on wells drilled and platforms constructed on each lease through 1976.

A detailed explanation of each revenue and cost category is presented in Appendix 1. At this point, it need only be noted that the major categories of revenues and costs employed in our analysis are derived from the historical records of the federal government--bonus, royalty, and rent payments, production, revenues, and the record of drilling by years. All other categories of costs are minor in relation to those which are known. Thus our input data must be presumed to be quite accurate, particularly in the aggregate.

Previous Research in this Area

Among the principal previous studies of the rate of return earned on offshore oil and gas investments are the following:

1. The analysis by W. Mead in Nossaman, et al., Study of the Outer Continental Shelf Lands of the United States, Public Land Law Review Commission, 1970, which estimated a 7.5% internal rate of return before taxes for 184 Louisiana OCS leases issued in 1954 and 1955. This analysis was based upon limited cost data and a limited production history.

2. The study by Weaver, et al., "Composition of the Offshore Petroleum Industry and Estimated Costs of Producing Petroleum in the Gulf of Mexico," U.S. Bureau of Mines, 1972, which contains valuable cost data, but where rates of return are estimated only for a hypothetical sample of successful (i.e., productive) tracts. Incidentally, the Weaver, et al. estimate of the pre-tax rate of return on productive leases (14% - 17%) is almost precisely equal to the IRR computed for productive leases only in the present study: 14.88% before taxes. These figures are not, however, indicative of the overall IRR on all leases because costs of dry leases have been excluded.

3. The study by E. Erickson and R. Spann, "The U.S. Petroleum Industry," in Erickson and Waverman (eds.) The Energy Question, Vol. 2, 1974, which analyzes only three lease sales (1972 and 1973), uses expected future and not actual revenues earned by the lease operator, and makes no attempt to develop new production cost data. The Erickson-Spann finding that actual bids in these three lease sales exceeded predicted bids based upon a discounted cash flow analysis is, however, supported by our conclusions.

4. Various reports released by the oil industry, typified by a paper presented by R. Bybee of Exxon, "Petroleum Exploration and Production on the Nation's Continental Shelves--Economic Potential and Risk," Marine Technology Society, 1970, which put the before-tax profitability of OCS lease investments at the level of about 7%. Such studies will probably be looked upon as self-serving, whatever their scientific merits. Few of them take proper account of future prices and production.

The validity of the present approach as compared to these previous studies may be judged by these considerations: (1) The current study uses a larger data base (1223 leases) than any previous study; (2) a longer and more detailed record of historical costs and revenues is used in the present analysis, as compared to hypothetical costs and revenues used in most other studies; and (3) future production, revenue, and costs have been explicitly modeled in the current study.

Methodology

This study uses two forms of economic analysis to determine overall profitability levels for the 1223 leases in aggregate and for sub-categories of these leases and to investigate questions relating to economic performance and expeditious development of leases. These methods are:

1. Internal rate of return analysis, in which a rate of return (or profit on investment) is computed for all leases and for sub-categories of these leases. IRR analysis is roughly comparable to discounted cash flow analysis, except that in IRR analysis the purpose of the formulation is to determine the actual rate of return earned on investment, whereas in discounted cash flow analysis an interest rate (or opportunity cost of capital) is specified in the model and the answer given is in terms of the present value of the investment. Our major contribution in this section is the determination of the IRR for leases and for various important sub-categories, where IRR is defined to be the rate of discount i which makes the present value of the stream of net revenue (or gross revenue [R_t] minus costs [C_t] for each year) equal to zero, in the equation:

$$\sum_{t=0}^{n} \frac{R_t - C_t}{(1 + i)^t} = 0$$

2. Multiple regression analysis, involving estimation of the parameters of a linear equation which explains variations in a dependent variable Y by means of variations in several independent variables X_i. The purpose of regression analysis is to explain the observed variation in the dependent variable and to highlight significant versus insignificant relationships between the dependent variable and individual independent variables. (For example, we determine to what extent the high-bid for individual leases is affected by (1) the number of bidders, (2) the economic size class of the winning bidder, (3) whether the winning bid was submitted jointly or by a single bidder, and (4) the actual value of recorded oil and gas production from each lease.)

In many cases, IRR analysis and regression analysis require comparison. This creates some problems of exposition in our report, for a conclusion relating to firm size reached as a result of IRR analysis may need to be restated in the light of the findings of the regression analysis. For simplicity of presentation, we have stated our IRR results first and our regression results later. We have attempted to point out complementarities and contradictions between the results in our Executive Summary.

Research Questions

The analysis carried out in this study has been guided by a desire to contribute to the policy debate concerning the effectiveness of federal management of OCS oil and gas resources. The central questions in this debate have been:

1. Has the federal government received fair market value for OCS leases?
2. Is the OCS lease sale market competitive?
3. Have large firms obtained leases at non-competitive prices?
4. Is there evidence that firms or particular classes of firms have not developed OCS leases in a diligent manner?

These research questions cannot be answered simply and directly. There are many definitions of "fair market value", "competition", and "diligence". What we have done is to formulate the issue in terms of a set of hypotheses which are capable of refutation. These hypotheses are then tested statistically, using various techniques. Finally, we present an interpretation of the results in the light of economic theory. Alternative interpretations are suggested wherever possible, but there is obviously room for additional interpretations by the reader.

Hypotheses

Economic theory and our study of industrial organization and performance lead us to presume that certain hypotheses are true. Our analysis will test each hypothesis, and will attempt to refute any for which our data indicate significant, alternative outcomes.

Hypothesis 1: If the OCS lease market is competitive, the internal rate of return on OCS investments should tend, over time, toward a normal return for assets in this risk category.

Hypothesis 2: The IRR for individual leases should tend to fall as the number of bidders rises because of the increased force of competition and the greater likelihood of higher-than-normal (outlyer) bids.

Hypothesis 3: Wildcat leases should earn a higher rate of return than drainage leases because they are more risky. Contrary results would occur only if competition for such leases was less intense or if certain bidders for drainage leases possessed information or cost advantages.

Hypothesis 4: Since joint bidding permits risk spreading, the IRR on joint-bid leases should be lower than the IRR on solo-bid leases. Contrary results would occur only if the advantages of information pooling are dominant or if joint bidders face less competition in bidding.

Hypothesis 5: The rate of return should be insensitive to the size of the bonus bid on tracts leased, except if the capital market is imperfect (i.e., large amounts of capital are not available on the same terms or to the same firms as small amounts of capital).

Hypothesis 6: Oil leases and gas leases should earn the same rate of return, assuming effective competition in both lease sale markets and product (output) markets, and if discovery (success) ratios in finding oil and gas are the same.

Hypothesis 7: The rate of return should be insensitive to the size of the firm winning the lease, except for possible economies of scale in information or engineering or monopoly power in lease bidding or product (output) markets.

Hypothesis 8: The rate of return for individual companies should tend toward the mean value for all leases as the number of leases rises, except for possible economies of scale in information or engineering or monopoly power in lease bidding or product (output) markets.

Economic theory makes no prediction concerning diligence of development, where "diligence" is defined in terms of speed in accomplishing early drilling, first production, or maximum production. Given a free choice, a firm holding an OCS lease will operate the lease with the objective of maximizing the present value of the lease. In some cases, this profit maximization rule will be consistent with rapid development; in other cases, the attempt to develop the lease more rapidly would lead to increased costs which would overwhelm the advantages of early receipt of revenues from production. If the present generation is consuming non-renewable oil and gas resources too rapidly, at the expense of future generations, then free markets will signal rapid future price increases for oil and gas, leading operators to delay present production. A delay in development in the latter two cases would represent a useful conservation of resources. Thus, rapid development of leases, without further information, is neither desirable nor undesirable, from a social welfare or resource conservation viewpoint. Nevertheless, since the OCS Lands Act speaks to the issue of "diligence of development", we have attempted to determine whether speed of development is related to any of the major variables in our analysis: firm size, type of lease, sale date, etc.

Some Important Caveats

Many questions of interest to policy makers cannot be answered by our analysis. We cannot, for example, determine whether certain firms are more efficient than other firms in lease development because our cost estimates are averages which have been applied uniformly to all lessees. The different IRR's for companies most strongly reflect different bidding strategies or success in discovering hydrocarbons. Only to a minor degree (i.e., the consistent choice by a company of the optimum number of wells to be drilled on a tract) will the relative level of engineering efficiency be reflected in the IRR. Similarly, we cannot measure two of the most important variables affecting the bidding for leases: pre-drilling knowledge of lease geology and the general state of expectations. We have used proxy variables to attempt to capture aspects of lease quality, but obviously our models are not completely specified. What can be learned from our study is, nevertheless, very important. In the sections which follow, we shall emphasize these positive conclusions, but we recognize that our ability to discern the lessons of the past is limited by the data at our disposal.

I. INTERNAL RATE OF RETURN ANALYSIS

Our first approach to the research questions concerning whether the federal government has received "fair market value" for its oil and gas leases, whether bidding for such leases has been effectively competitive, and whether the cash bonus bidding system facilitates competition for oil and gas leases, is based on an analysis of the internal rate of return earned by lessees. Our IRR analysis rests on the assumption that an effectively competitive leasing system yielding fair market value to the government will allow only normal rates of return on investments for lessees. Conversely, if competition under the cash bonus bidding system is inadequate and payments to the government represent less than fair market value for the leases, then one would expect to find lessees earning higher than normal competitive rates of return on their investments.

Computation of the internal rate of return on the 1954-1969 leases is a relatively straight-forward operation. Part of the lessee costs are known with precision. On the cost side, exact data are available on all bonus payments, royalties, and rent payments from 1954 through 1978. We have estimated pre-sale exploration costs, post-sale exploration and development costs, and operating costs. Based on the 1978 record for producing leases and using a 15 percent decline rate for production, we have estimated production costs through the point of shutdown (defined as the year in which costs exceed revenues for each lease individually, with all leases still operating being shutdown in 2010).

On the revenue side, exact data are available on lease-specific liquids and gas production and revenue through 1978. Using a standard price scenario for oil and gas, we have projected production and revenue on a lease-specific basis to the point of shutdown. We then conducted sensitivity analyses to show the effect on the IRR of alternative future price increases and production decline rates.

Internal Rate of Return Findings.

Using our standard price scenarios for oil and gas, the internal rate of return for all 1,223 leases is estimated at 11.43 percent before taxes (see Table 1). This estimate, based on the entire life cycle of each lease, is low relative to before tax rates of return for comparable U.S. industries. For example, all manufacturing firms in the U.S. earned an average of 19.81 percent rate of return before taxes on equity capital over the years 1954 through 1976.[2] Thus, the estimated IRR on OCS oil and gas leases is approximately 42 percent below normal competitive returns on capital.[3]

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[2] Federal Trade Commission, Quarterly Financial Reports of Manufacturing Corporations. Washington, D.C., U.S. Government Printing Office, 1954-1977.

[3] In our January 1979 Interim Report to the U.S. Geological Survey, we reported a 9.45 percent internal rate of return for the 1954-1969 leases. The higher IRR estimated in our Final Report reflects the following changes: (1) the Interim Report was based on recorded production through the year 1976. The Final Report is based on production records through the year 1978. (2) Projections of future production are based on the 1978 record rather than in 1976. (3) Revenue for 1977 and 1978 reflects the actual prices received in these years including higher prices brought on by the Iranian crisis beginning in late 1978, whereas, the Interim Report was based on scenario prices for these two years. (4) Our standard price scenario has been revised upward to reflect the substantial price increases occurring in 1979 and beyond. (5) Exploration and drilling cost estimates have been revised. (6) The number of well completions was reduced to correct for an overstatement contained in the LPR-19 data base provided by USGS. (7) A well abandonment algorithm was added to reflect the cost of this essential operation under current and expected future cost conditions.

TABLE 1.

INTERNAL RATES OF RETURN -- 1223 OCS LEASES ISSUED 1954-1969

	Number	IRR (%)	Gas/Oil Ratio (BTU's)	Average Bonus ($M) per Lease	Average Gross Value of Production ($M) Through		Average Net Cash Flow ($M) Through	
					1978	2010	1978	2010
All Leases	1223	11.43	1.38	2,228	14,644	37,414	3,750	15,968
Big 8	725.1	10.91	1.00	2,310	14,911	35,281	3,421	13,794
Big 9-20	298.6	12.21	2.69	2,354	14,762	41,228	4,706	20,223
Non-Big 20	199.3	11.90	1.50	1,743	13,494	39,458	3,514	17,507
Solo	861	10.43	1.22	1,848	12,701	31,079	2,710	12,237
Joint	362	13.07	1.64	3,133	19,264	52,481	6,226	24,844
Wildcat	1079	10.57	1.45	1,932	12,675	32,754	2,808	13,502
Drainage	144	15.9	1.14	4,452	29,397	72,333	10,809	34,447
1 Bidder	411	13.37	1.56	470	7,010	17,622	2,281	7,815
2 Bidder	245	12.76	2,80	955	9,035	24,234	2,619	11,110
3/4 Bidder	254	12.76	.97	2,421	19,134	46,235	5,343	19,044
5/More Bidder	313	10.00	1.29	5,378	25,398	66,560	5,272	27,982
Bonus ≤ $250,000	354	12.09	1.55	126	4,093	12,141	1,100	5,571
Bonus ≤$1,000,000	367	11.96	1.65	525	8,393	21,561	2,221	8,790
Bonus ≤$3,250,000	285	12.41	1.38	1,875	18,427	45,781	5,453	19,871
Bonus >$3,250,000	217	10.55	1.25	9,002	37,456	94,464	8,407	39,945

[1] Attributed shares for firm categories.

Sensitivity Analysis

In order to determine how sensitive our IRR estimates are to alternative assumptions, we have performed sensitivity analyses for both alternative price scenarios and alternative production decline rates. The results are shown in Table 2 and Figure 1 . We find that if our standard price forecast is lowered by 10 percent, the internal rate of return declines to 11.04 percent. Alternatively, if our standard price forecast is raised by 20 percent, the internal rate of return becomes 12.10 percent. Even if the future revenue stream is increased by 50 percent, the IRR remains a sub-normal 12.96 percent. Our standard price scenario would have to be raised by approximately 210 percent before a 20 percent before-tax rate of return would be attained. These relatively small profitability responses to alternative price scenarios support our conclusion that the government received more than fair market value for its leases. The reasons for the lack of IRR sensitivity are (1) any change in the price scenarios affects future values which are then discounted to the base year 1954; and (2) our tests of sensitivity affect only a small proportion of the leases in our study, those which were productive beyond 1978.

From 1954 through 1970, the year before President Nixon imposed a wage-price freeze, the wellhead price of crude oil in the U.S. remained relatively constant (1954 = $2.78/bbl., 1970 = $3.18/bbl.). The inflation-adjusted price actually declined by 9 percent. Bidders for oil and gas leases may have expected price increases to occur over these years. The absence of significant price increases, therefore, may account for the observed low rates of return.

Table 2 also shows two different assumed production decline rates for years beginning in 1979. Substituting a 10 percent decline rate and continuing our standard price scenario, the internal rate of return would increase to 12.63 percent. In the other direction, a 20 percent decline rate would cause a

Table 2.

SENSITIVITY OF INTERNAL RATE OF RETURN ESTIMATES TO ALTERNATIVE PRICE SCENARIOS AND PRODUCTION DECLINE RATES

Alternative price scenarios	Estimated IRR
10% below standard scenario	11.04%
Standard scenario	11.43%
10% above standard scenario	11.73%
20% above " "	12.10%
30% above " "	12.41%
40% above " "	12.70%
50% above " "	12.96%
Alternative production decline rates	
10% decline rate	12.63%
15% (standard rate)	11.43%
20% decline rate	10.51%

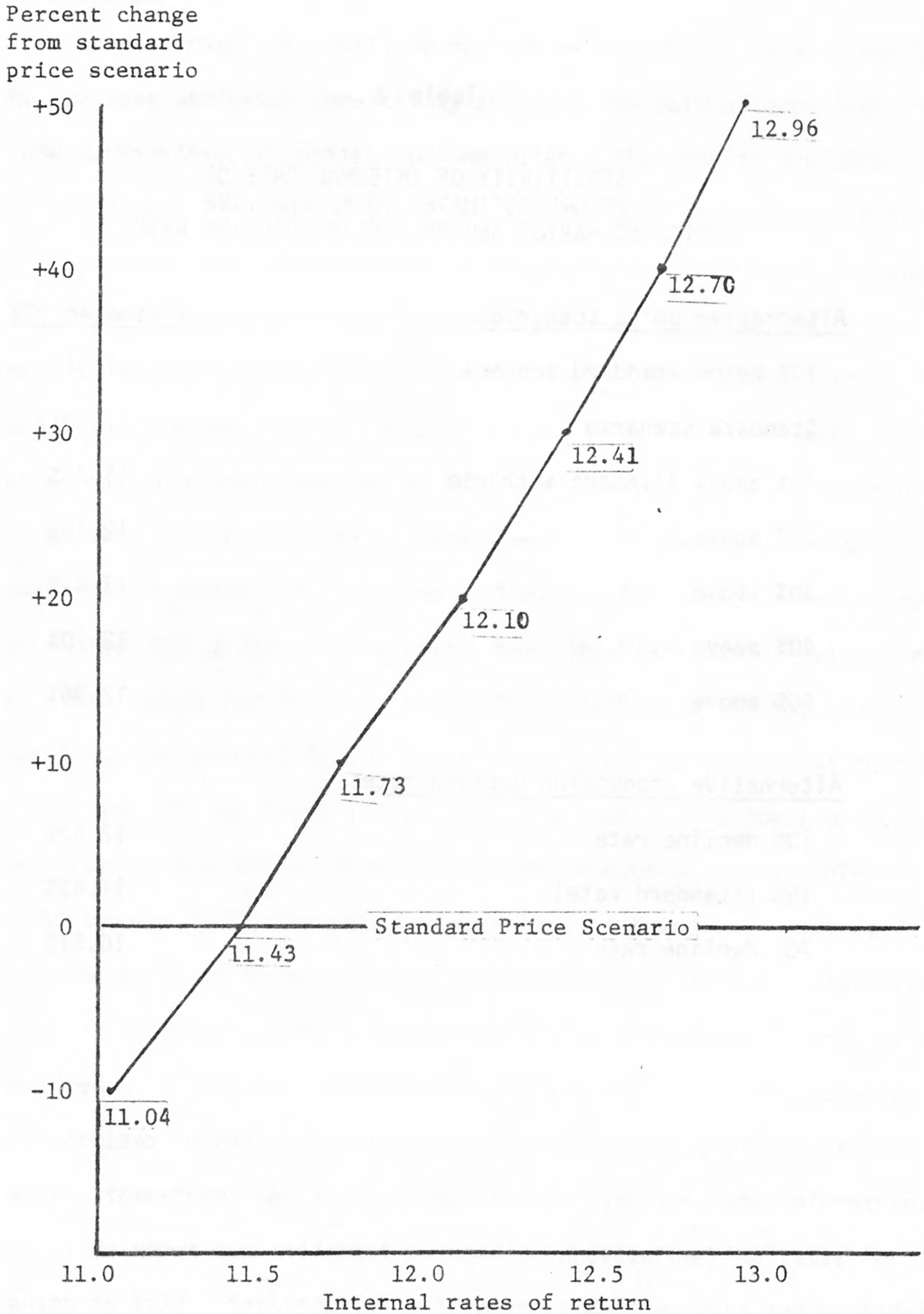

Figure 1 --. Aggregate internal rates of return for alternative price scenarios.

reduction in the estimated IRR to 10.51 percent.

In summary, either a 50 percent increase in our standard price scenario or a reduction in the production decline rate to 10 percent would produce internal rates of return which are still substantially below historical returns on equity in similar investments within the U.S. economy.

If we assume that 20 percent is the normal, competitive before-tax return on investments in this period for the degree of risk involved in oil and gas exploration and production, then we find that lessees suffered a net loss in present values in 13 of the 17 lease sales included in our study (only four small drainage sales yielded a normal or better return). The average loss was $1.570 million for all 1223 leases, or $1,919.76 million total (see Table 3). Since it is unlikely that these losses were the result of inefficiencies brought about by the oil industry in development and production, they may properly be regarded as evidence of overbidding resulting in payments to the government in excess of fair market value for the leases.

If lessees had correctly estimated reserves, production, prices and all costs for these 1223 leases, instead of bidding an average bonus of $2.228 million per lease as shown in Table 1, they would have bid only about $658,000 ($2,228,000 - 1,570,000) per lease, assuming a before-tax discount rate of 20%. At this discount rate, the federal government's share of net economic rent for these 17 lease sales equals 244%.[1]

Table 1 provides data on both gross and net cash flows through the year 1978 and through the point of abandonment (or 2010). The average undiscounted net cash flow through 1978 for all leases before taxes is $3,750,000. Through 2010, the undiscounted net cash flow is $15,968,000 on average before taxes. The net cash flow through 2010 yields our figure for aggregate IRR: 11.43%.

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[1]See the Executive Summary Table, p. ix.

Trends in Internal Rates of Return

We have seen above that the aggregate internal rate of return is substantially below normal before-tax competitive returns. Economic theory suggests that with effective competition and efficient markets, internal rates of return in successive lease sales should regress toward a normal competitive rate of return for assets in comparable risk categories.

The first experience of the industry with OCS leases in the Gulf of Mexico clearly resulted in overbids. For the 184 leases purchased in 1954 and 1955, the internal rate of return was 7.84 percent before taxes. These results suggest that in the initial bidding experience of 1954-55, bidders expected to find and produce far more oil and gas than actually occurred. It is also likely that this result was connected to the industry's earlier success in leasing offshore lands from the state of Louisiana which were later declared to belong to the federal government (see Part II below). At any rate, with experience, bidding enthusiasm was moderated slightly with the result that returns tended toward a competitive norm. However, it is clear that, on a before-tax basis, bidding through 1969 yielded substantially more than fair market value to the federal government and substantially less than normal competitive rates of return to lessees. (See Table 3.)

The analysis above applies most accurately to wildcat leases; drainage lease sales came much closer to mirroring the expected competitive results. Internal rates of return before taxes by lease sale have been plotted in Figure 2 . We see immediately that rates of return on investment differ sharply between drainage and wildcat leases. Drainage leases are defined as leases adjacent to known productive areas; wildcat leases are located outside of known productive regions. Table 1 shows that wildcat leases as a group earned a 10.57 percent internal rate of return whereas drainage leases earned 15.9 percent.

Table 3. PRESENT VALUES OF SEVENTEEN LEASE SALES DISCOUNTED AT 20 PERCENT TO DATE OF EACH LEASE SALE, WITH BONUS AND OTHER PAYMENTS TO GOVERNMENT INCLUDED (BEFORE TAX BASIS)

Sale date	W-Wildcat D-Drainage	Present value of all leases sold discounted at 20%1/	Number of leases sold	Average Present Value per Lease discounted at 20%
10-13-54	W	-184,381,520	90	-2,048,684
11-09-54	W	-27,648,080	19	-1,455,162
07-12-55	W	-141,211,200	121	-1,167,035
05-26-59	W	-6,385,487	23	-277,630
08-11-59	D	-75,162,048	19	-3,955,897
02-24-60	W	-150,798,000	147	-1,025,837
03-13-62	W	-182,097,920	206	-883,970
03-16-62	W	-235,233,664	205	-1,147,481
10-09-62	D	-14,069,266	9	-1,563,252
04-28-64	D	+23,390,896	23	+1,016,995
03-29-66	D	+43,085,312	17	+2,534,430
10-18-66	D	-38,099,200	24	-1,587,467
06-13-67	W	-369,721,344	158	-2,340,009
05-21-68	W	-610,466,560	110	-5,549,696
11-19-68	D	+47,034,032	16	+2,939,627
01-14-69	D	-16,366,057	20	-818,303
12-16-69	D	+18,365,744	16	+1,147,859
Total		-1,919,764,362	1223	
Average per lease		-1,569,717		

[1] This rate of discount was chosen to most closely reflect the rate of return on equity for all U.S. manufacturing corporations over the years 1954-76 (19.81%).

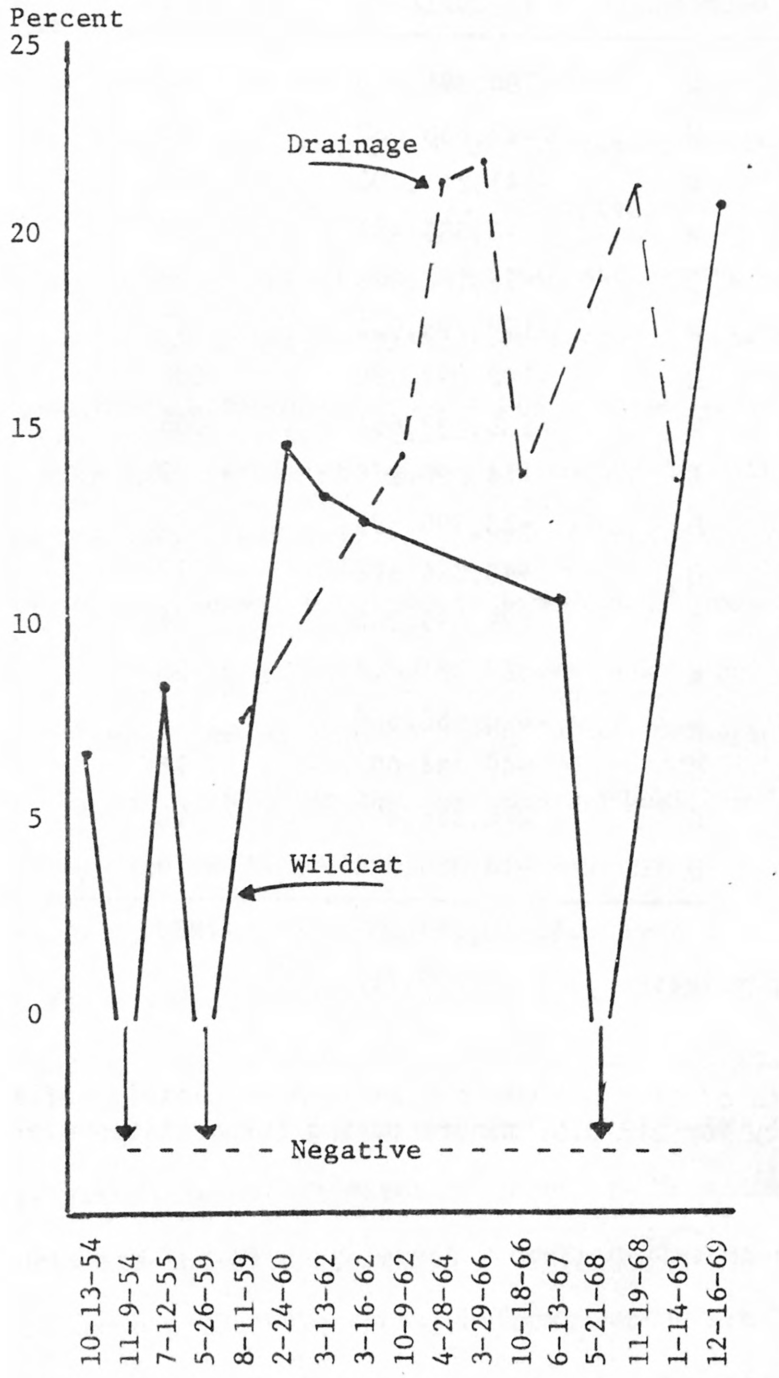

Figure 2 --. Internal rate of return by lease sale, 1954-1969

In both drainage and wildcat lease sales there is a clear tendency for the resulting IRR's to regress toward normality. The first drainage lease sale yielded a relatively low 7.60% IRR. All subsequent drainage sales yielded between 13 and 22 percent before taxes.

In the case of wildcat leases, an upward trend in IRR is apparent. However, this trend cannot be proven by simple regression because three of the wildcat lease sales were dry and generated an undefined negative return.

Our hypothesis suggests that average rates of return for these two lease categories would be the opposite of those observed in Figure 2. Wildcat leases involve a higher degree of both risk and uncertainty and therefore should earn a risk premium relative to drainage leases. An explanation for the very low average IRR on wildcat leases (10.57 percent before taxes) and the persistently low rates on a sale-by-sale basis may be found in the peculiarities of the oil industry. There appears to be a bidder preference for high-risk based on hopes of finding another "gusher". This may enhance the effect of the "winner's curse," or the fact that the bidder who most over-values the tract is always the winner. It may also be true that buyers of wildcat tracts are implicitly investing in proprietary information which they will obtain concerning adjacent acreage. Such information could later be capitalized in subsequent drainage lease sales. In this case, the premium paid for wildcat acreage might be economically rational.

The Dry Lease Record

The majority of leases involved in this study -- 61.9 percent -- were dry, as is indicated in Table 4. These 757 leases had no oil or gas production and were abandoned. Another 15.0 percent (183 leases) were productive but unprofitable (costs exceed revenue over the life of these leases). The

TABLE 4. RECORD OF PROFITABLE, PRODUCTIVE BUT UNPROFITABLE, AND DRY LEASES.

	Number	Percent	IRR
All leases	1,223	100.0	11.43%
Profitable	283	23.1	19.40%
Productive but unprofitable	183	15.0	Negative
Dry leases	757	61.9	Negative

remaining 23.1 percent (283 leases) were both productive and profitable, yielding an internal rate of return of 19.40%. These profitable leases "carried" the remaining 76.9% of the leases, resulting in an aggregate IRR of 11.43 percent, as reported earlier.

Oil and Gas Leases Compared

If bidders were able to distinguish oil from gas properties with a high degree of accuracy prior to bidding and exploration, if discovery risks were the same, and if future price expectations were similarly fulfilled, the internal rates of return on oil and gas leases would be approximately equal. In fact, future price expectations were not borne out (in particular because natural gas was regulated at a lower price for a longer period of time than bidders expected) and thus rates of return on oil and gas leases diverge significantly.[1] During the 1954-1969 bidding period under study, oil discoveries were given top priority while gas (because of its regulated environment) was viewed as a consolation prize, better than a dry hole.

The record shows that leases producing oil, including leases that were productive but unprofitable, earned a 16.27 percent IRR, compared to 13.40 percent for gas-producing leases (see Table 5). Reflecting the greater profitability of oil, the average bonus for oil-producing leases was 76 percent higher than for gas leases.

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[1]Oil leases are distinguished from gas leases in our analysis on a physical basis. If the BTU value of liquids production on a lease through 2010 exceeds the BTU value of gas production, the lease is called an oil lease, and vice-versa. The energy conversion rate used was 5.68 mcf gas = 1 bbl. crude oil. Only leases which actually produced can be defined as "oil" or "gas" leases, and thus dry hole costs of all remaining leases have been allocated to productive leases in proportion to the number of oil vs. gas leases.

TABLE 5. PRODUCTIVE[1] OIL AND GAS LEASES

	Oil			Gas		
	Number	IRR (Percent)	Average bonus (000 dollars)	Number	IRR (Percent)	Average (000 do
Productive Leases Only (No Dry Lease Costs)	166	16.27	4,592	300	13.40	2,6
With Dry Lease Costs Allocated Proportionately to Productive Leases	166	13.52	7,125[2]	300	9.43	5,1

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[1] Includes profitable leases and productive but unprofitable leases.

[2] These figures represent the actual average bonus costs for productive leases plus bonus costs of dry leases, allocated in the proportion 166/300.

The reader should be cautioned against careless use of IRR data relating to productive leases only. These returns fail to take account of the necessary (expected) costs of dry leases. In order to estimate the true rates of return for oil and gas leases including dry lease costs, we have allocated the negative cash flow for dry leases in each year to productive leases in proportion to the number of oil vs. gas leases, as shown in Table 5. After dry lease costs are allocated, oil leases earned 13.52 percent, gas leases earned 9.43 percent.

Rate of Return by Size of Firm

An important issue of concern to policymakers involves the performance of large firms in the OCS lease sale market. Concern has been expressed by Congress that "big oil companies" may have an unfair advantage in bidding for oil and gas leases. As a result, they may obtain leases for relatively low prices and consequently earn relatively high rates of return. In Part III, our regression analysis will test for significant differences in high bid by size of firm. Our concern here is limited to the IRR.

Congressional reference to large firms is usually in terms of size of firms rather than their share of total acreage obtained in OCS lease sales. Accordingly, we have identified the Big-20 firms by size based on their worldwide sales in the year 1969. This year is in the middle of our production period and is the terminal year for lease sales analyzed in this report.

The Big-8 and the Big 9-20 firms are identified in Table 6. Our analysis of internal rates of return earned by the Big-8 and Big 9-20 firms corresponds with the firm names shown in Table 6. We will point out later that when firms are ranked by OCS acreage acquired in the 1954-1969 lease sales, the ranking does not correspond precisely with the ranking by firm sales as shown in Table 6.

Table 6.

The Twenty Largest U.S. Oil Companies, Ranked by Worldwide Sales, 1969[1]

Big-8

1. Exxon
2. Mobil
3. Texaco
4. Gulf
5. Standard Oil of California
6. Shell
7. Standard Oil of Indiana
8. Arco

Big 9-20

9. Tenneco
10. Continental
11. Phillips
12. Occidental
13. Sun
14. Union
15. Cities
16. Signal
17. Standard Oil of Ohio
18. Ashland
19. Getty
20. Marathon

[1] Some small changes in identification of the largest twenty oil companies have occurred in this listing as compared to that used in our Interim Report which based its rankings on sales in 1962. The only important changes are that Arco replaced (merged with) Sinclair on the Big-8 list; Tenneco, Occidental and Signal were added to the Big-20, replacing Pure, Sunray DX and Atlantic, all of which were merged into firms listed among the current Big-20.

We have hypothesized that the internal rate of return as we have measured it should be insensitive to firm size. Our firm-specific data are limited to (1) all payments to the government; (2) number of wells drilled and well depth for each; and (3) value of production for oil and gas, all by year. Any other differences in costs which might reflect economies of scale or efficiency in operation by specific firms would not be reflected in our rate of return findings.

As shown in Table 1, the Big 9-20 class of firms earned the highest IRR: 12.21 percent. The lowest return is found for the Big-8 firms at 10.91 percent. The category of non-Big-20 firms is in an intermediate position earning 11.90 percent.[1]

These findings do not support the argument that large firms, defined as the Big 20, exercise monopsony power in the lease sale market. Instead our findings indicate that all firms other than the Big-20 earned 11.90 percent rate of return whereas the Big-20 firms earned 11.34 percent (Table 7).

The data shown in Table 1 provide no clear explanation for the observed differential rates of return by firm size class. The Big 9-20 size class paid the highest average bonus, but was second highest in terms of gross production value through the year 1978. Projected revenue after 1978 is based on recorded production by lease in the year 1978. The fact that the Big 9-20 size class shows the highest gross production value through the year 2010 indicates that this group recorded a relatively high level of production in 1978. The average net revenue flow through both 1978 and 2010 was highest for firms in the Big 9-20 group. Since this group paid the highest average bonuses, it must have drilled less wells (or fewer dry wells) per unit of production or revenue.

[1] Since these computed IRR's are aggregate returns by size class (not averages for the individual firms in each class), we have no way to test the hypothesis that there is no significant difference in IRR by firm class.

Table 7. INTERNAL RATE OF RETURN AND NUMBER OF LEASES, BIG-20 AND ALL OTHER FIRMS

	Number of leases[1]	IRR
Big-20 firms	1,023.7	11.34
All other firms	199.3	11.90
Total	1,223	11.43

[1]Based on attributed shares of leases

Big-8 firms recorded the lowest IRR. The pattern of average gross production value through 1978 compared to post-1978 indicates that large firms may have produced their oil and gas faster than other firms and thereby failed to benefit from the substantially higher prices on production occurring after the Arab oil embargo of 1973-1974.

Average Bonus by Firm Size Class

If firms bid rationally for oil and gas leases, then we would expect to find that the highest bids were cast for leases which turned out to be both productive and profitable, that the lowest bids were for dry leases, and that bids for productive but unprofitable leases were in an intermediate position.

This hypothesis is supported by the bidding results as shown in Table 8. The analysis hold for all three firms size classes. Table 8 also shows that firms bid higher bonuses for leases which turned out to be primarily oil rathe than gas-producing leases. This bidding pattern reflects the fact that, in th early years of OCS development, natural gas prices were extremely low and gas pipelines were not available to transport natural gas from offshore leases to onshore pipelines and markets.

TABLE 8. AVERAGE BONUS PER LEASE BY FIRM SIZE CLASS FOR DRY AND PRODUCTIVE OIL AND GAS LEASES ($M)

Type of Lease	Firm Size Class			Total for All Firms
	Big-8	Big 9-20	All Other	
Profitable leases	3,405	4,041	3,215	3,540
Productive but unprofitable leases	3,397	3,025	1,561	2,967
All productive leases	3,402	3,719	2,509	3,115
Oil	3,663	6,716	7,264	4,592
Gas	3,200	2,725	1,044	2,609
Dry Leases	1,651	1,568	1,185	1,559
All (1223) Leases	2,310	2,354	1,743	2,228

The hypothesis that bidding is rational is further supported by the data in Table 9, which indicate a consistent, positive relationship between size of bonus paid for leases and the percentage of leases which ultimately produced either oil or gas. As average bonus rises, the percentage of leases proved ultimately to be productive also rises, from 18.6 percent for the lowest average bonus category of leases up to 58.1 percent for the highest average bonus category.

Table 9. PERCENT OF LEASES THAT WERE PRODUCTIVE BY BONUS SIZE CLASS.

Bonus size class	Percent productive
≤$250,000	18.6
$250,001-$1,000,000	35.1
$1,00,001-$3,250,000	50.9
>$3,250,000	58.1

Performance by Individual Lessee Firms

We have developed performance data by individual firm for the 25 largest lessees, ranked not by firm size but by number of acres leased in 1954-1969 Gulf of Mexico lease sales. The results are shown in Appendix 8, Table 34. The share of total acreage leased by Big-8 firms is 61.8%; for the Big-4, the share is 42.6%. Similar levels of concentration are shown for production of liquids and gas from the 1223 leases (see Tables 10 and 11). The marked decline in the Big-8 share of liquids production (since 1955) and gas production (since 1966) would not have been observed in markets characterized by significant monopoly power. Nor would the shares in production of liquids and gas of the non-Big-20 firms have risen as rapidly since 1960 as these tables indicate.

Table 10.

Concentration in Production Volumes by Year
1223 Leases Issued 1954-1969

	LIQUIDS % produced by			GAS % produced by			VOLUME PRODUCED	
Year	BIG8	BIG9-20	NONBIG20	BIG8	BIG9-20	NONBIG20	LIQUIDS (barrels)	GAS (MCF)
1954	0.0	0.0	0.0	0.0	0.0	0.0	0	0
1955	100.0	0.0	0.0	0.0	0.0	0.0	37760	0
1956	82.4	4.3	13.3	0.0	0.0	0.0	541475	0
1957	64.8	10.8	24.4	0.0	0.0	0.0	1376126	0
1958	61.2	24.7	14.1	0.0	0.0	0.0	3085867	0
1959	72.5	17.3	10.2	22.8	66.9	10.3	5167880	14583108
1960	72.6	20.3	7.1	45.6	51.3	3.1	7319239	41344949
1961	76.5	18.2	5.3	46.9	50.1	3.0	11879226	55326507
1962	78.9	16.2	4.9	43.6	47.0	9.4	17742822	102587926
1963	80.6	16.3	3.1	51.4	40.7	7.9	26446236	140695210
1964	83.7	13.7	2.6	56.4	36.0	7.6	36642526	179148676
1965	87.2	10.6	2.2	62.2	29.9	7.9	52642725	188909399
1966	85.7	12.0	2.3	75.3	15.9	8.8	84928354	392292482
1967	82.0	15.3	2.7	66.7	25.2	8.1	110960145	548422466
1968	80.0	15.8	4.2	67.1	24.3	8.6	142374745	758872271
1969	76.1	15.7	8.2	58.9	27.3	13.9	173471769	1141645010
1970	71.5	15.5	13.0	51.4	33.5	15.1	204840103	1573233277
1971	67.3	13.9	18.8	50.9	30.5	18.6	251164786	1913821356
1972	66.8	15.9	17.3	49.5	31.4	19.1	252169979	2183640652
1973	66.6	16.0	17.4	48.4	34.2	17.4	236921579	2063123746
1974	64.2	18.1	17.7	43.6	36.7	19.7	212529708	2122197954
1975	63.1	19.3	17.6	44.5	37.9	17.6	180470802	1926007925
1976	62.7	18.3	19.0	44.6	37.2	18.2	162893254	1761492386
1977	61.2	18.9	19.9	46.9	36.1	17.0	141020032	1550827833
1978	60.3	18.5	21.2	47.3	36.3	16.4	123239478	1532695868
Forecast Period								
1979	60.3	18.5	21.2	47.3	36.3	16.4	106072933	1319203206
1980	60.3	18.5	21.2	47.3	36.3	16.4	91297771	1135448732
1985	60.3	18.5	21.2	47.3	36.3	16.4	43052095	536075234
1990	60.2	18.5	21.3	47.2	36.4	16.4	20290570	252878126
1995	59.7	18.8	21.5	47.0	36.5	16.5	9454477	119102807
2000	59.2	19.0	21.8	46.8	36.6	16.6	4408524	56010896
2005	58.7	18.9	22.4	46.0	37.2	16.8	1987503	25936953
2010	57.9	19.7	22.4	44.8	38.1	17.1	901818	11936401

Table 11.

Concentration in Production Volumes Through 2010

LIQUIDS			GAS		
% produced by			% produced by		
BIG8	BIG9-20	NONBIG20	BIG8	BIG9-20	NONBIG20
67.4	16.8	15.8	49.2	34.4	16.4

Concentration in OCS Acreage Purchased 1954-1969

BIG8	BIG9-20	NONBIG20
59.3	24.4	16.3

Economic theory would not lead one to expect performance results to show any systematic differences by firm size ranked by acreage purchased. For easy verification of this hypothesis we have plotted in Figures 3 through 6 the relationship between firm size on one hand and four performance variables on the other hand as follows: (1) the internal rate of return, (2) the average bonus bid per lease, (3) the ratio of gas revenue to to total revenue, and (4) the average lag in years from sale date to first production on productive leases.

We find that none of these four performance variables is systematically related to firm size as measured by acres leased in the 1954-1969 lease sales. Linear trend lines fitted to the performance data show no statistical significance. Similarly, mean values computed for the Big-8 firms and all other firms show no significant differences.

Firm Size Relative to Sale Type

There is interest in determining whether the number of leases purchased by firms in different size classes (Big-8, Big 9-20, and all other firms) is related to sale type including the following: (1) solo versus joint, (2) wildcat versus drainage, (3) number of bidders competing for a given tract, and (4) the size of the bonus submitted by the winning bidder. We can test hypotheses asserting that there is no relationship between firm size of the high bidder and these four variables. The data for these tests are presented in Table 12. Hypotheses will be tested by means of chi-square analysis.

The null hypothesis asserting no relationship between firm size and solo versus joint bidding must be rejected. ($X_o^2 = 43.94$, $X_{.95}^2 = 5.99$). The results support the conclusion that Big-8 firms win proportionately far more leases on a solo-bidding basis (far less on a joint bidding basis) than non-Big-8

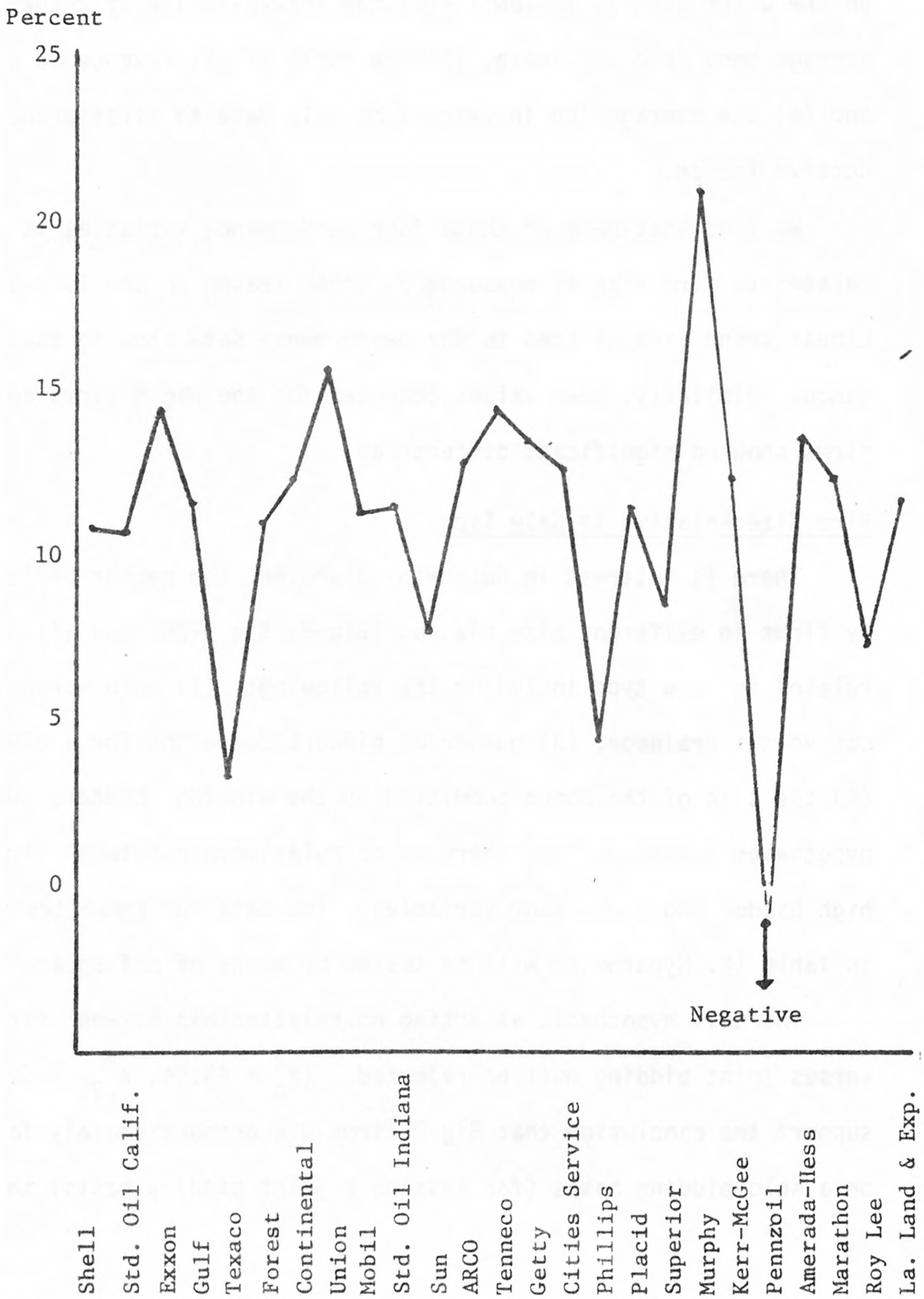

Figure 3 --. Relationship between Internal Rate of Return and firm size ranked by acres leased in 1954-1969 lease sales.

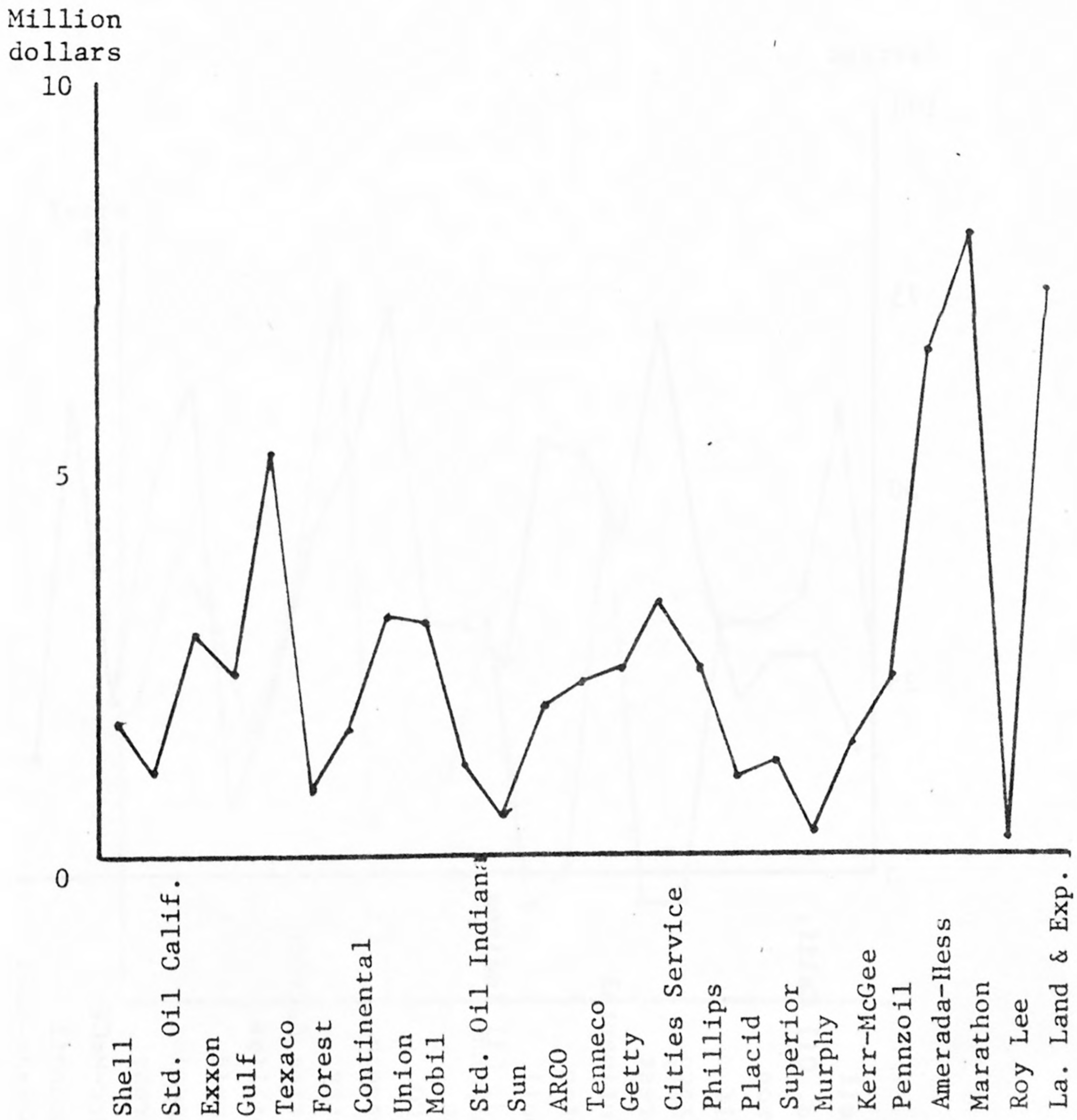

Figure 4--. Relationship between bonus bid per lease (high bid) and firm size ranked by acres leased in 1954-1969 lease sales.

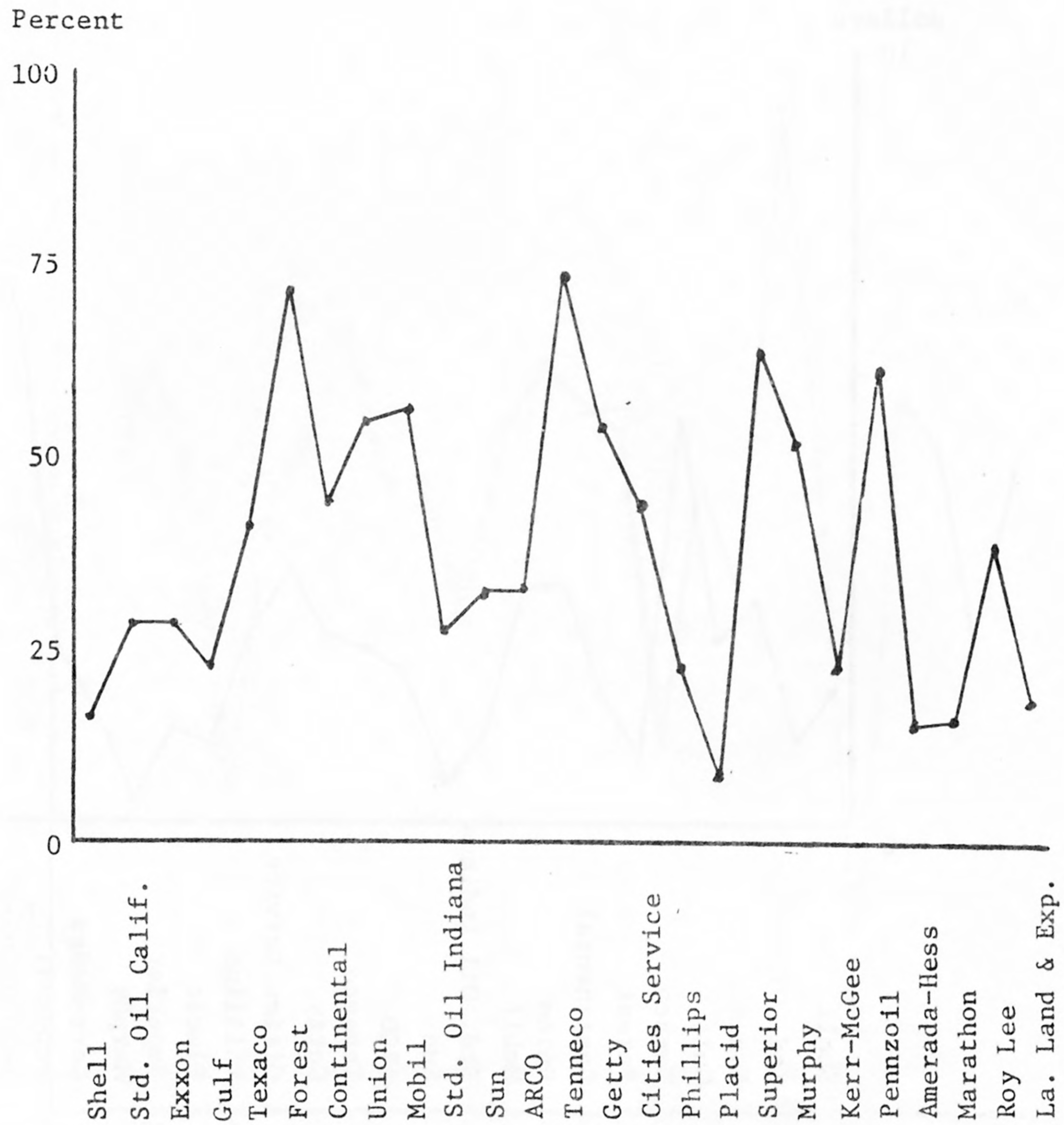

Figure 5 --. Relationship between gas revenue as a percent of total revenue and firm size ranked by acres leased in 1954-1969 lease sales.

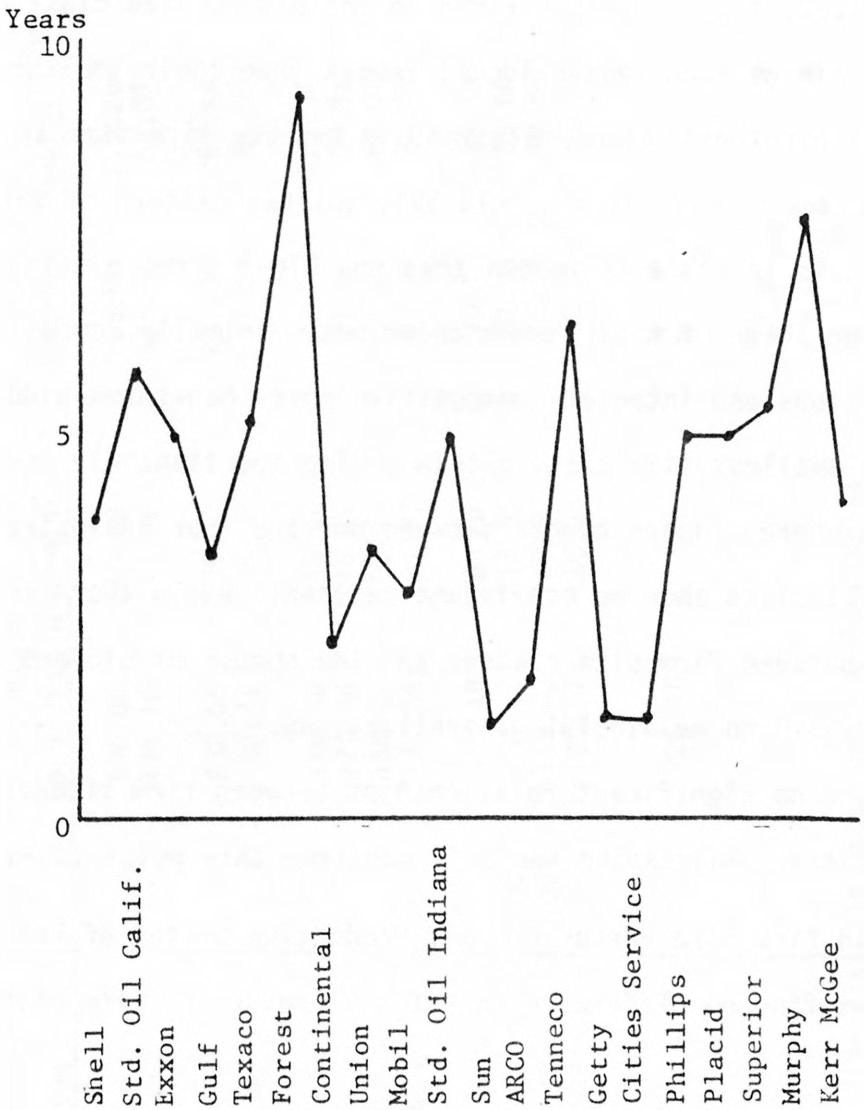

Figure 6 --. Relationship between average lag in years from sale to first production on productive leases, and firmsize ranked by acres leased in 1954-1969 sales.

firms.[1] For the Big 9-20 firms, a proportionately greater number of leases are acquired on a joint bidding basis than in solo bids. Non-Big-20 firms show no apparent preference for either the solo or the joint bidding approach.

The record of leases won when classified by wildcat versus drainage sales indicates no consistent relationship with firm size classifications. (X_0^2 = 4.84, $X^2_{.95}$ = 5.99). However, if the two largest firm size classes are combined into a Big 20 group, we then find significant differences between the 20 largest firms and all other firms with respect to wildcat and drainage leases won. (X_0^2 = 4.82, $X^2_{.95}$ = 3.84). Firms in the Big 20 size class win proportionately more drainage (and less wildcat) leases than their smaller competitors.

The null hypothesis of no relationship between firm size and number of bidders is rejected (X_0^2 = 12.73, $X^2_{.95}$ = 12.59), but the pattern of relationships is not clear. The data in Table 12 reveal that the Big-8 firms obtain a disproportionately high share of their leases under both minimally competitive one-bidder conditions and intensely competitive more-than-three-bidder conditions. Firms in the smallest size class obtain a disproportionately large share of their leases where bidders number between one and four inclusive. The Big 9-20 firm size class show no consistent pattern. While there are significant differences between firm size classes and the number of bidders classification, the results yield no meaningful generalizations.

There are no significant relationships between firm size class and bonus size class. Regression analysis confirms this point in Part III, below.

Difference in Firm Size versus Dry and Productive Status of Lease

While we find no difference in rates of return by firm size ranked by

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[1] Leases that are won on a joint bidding basis are assigned to the jointly bidding firms on the basis of attributed shares in each lease.

Table 12. NUMBER OF LEASES IN SALE-TYPES, OBSERVED AND THEORETICAL, BY WINNING FIRM SIZE CLASS, BASED ON ATTRIBUTED SHARES.

	Firm Size Class[1]						
	Big-8		Big 9-20		All Other		
Sale Type	Observed	Theoretical[2]	Observed	Theoretical[2]	Observed	Theoretical[2]	Total
Solo	550.00	510.48	165.00	210.20	146.00	140.33	861
Joint	175.10	214.62	133.57	88.37	53.33	59.00	362
Wildcat	632.66	639.72	261.34	263.42	185.00	175.86	1,079
Drainage	92.44	85.38	37.23	35.15	14.33	23.47	144
One Bidder	248.38	243.68	92.24	100.34	70.38	66.99	411
Two Bidders	128.46	145.26	71.04	59.81	45.50	39.93	245
3-4 Bidders	156.67	150.59	51.45	62.01	45.88	41.40	254
5 or More Bidders	191.59	185.57	83.84	76.41	37.57	51.01	313
Bonus ≤ $250,000	210.49	209.88	79.17	86.42	64.34	57.70	354
250,001 - $1,000,000	204.61	217.59	91.41	89.60	70.98	59.82	367
$1,000,001-$3,250,000	179.03	168.97	65.34	69.58	40.63	46.45	285
> $3,250,000	130.97	128.66	62.65	52.98	23.38	35.37	217
Total Each Class	725.10		298.57		199.33		1,223

[1]Firm size class is based upon world-wide sales.

[2]Predicted number based upon total number of leases in each comparison category.

leases won,we may still ask whether firms in different size classes differ in their ability to correctly diagnose and then purchase leases which turn out to be both profitable and productive relative to those leases that are productive but unprofitable and dry leases. Economic theory would suggest the null hypothesis.

The data to test this hypothesis are shown in Table 13. A chi-square test indicates no significant difference in occurrence of profitable, productive but unprofitable, and dry leases by firm size ($X_0^2 = 5.17$, $X_{.95}^2 = 9.488$). Whe large firms are combined into a single Big-20 classification, the null hypothesis is again accepted. There is no evidence that success in winning producti versus dry leases is related to the size classes of firms which we have identified.

Rates of Return on Solo vs. Joint-Bidder Leases

The practice of joint bidding has been criticized as having anti-competit results. These results are alleged to occur when two or more large firms fully capable of bidding independently join together and submit only one bid. If this were the dominant effect of joint bidding, this practice would appear to reduce competition for leases. It is equally possible, however, that firms that join together in a single bid may, as a result, bid more frequently. Furthermore, small firms are able to enter the bidding market through joint bidding thereby increasing the number of effective competitors. Joint bidding may be further justified by reference to economic advantages flowing from risk spreading and information pooling, both of which put smaller firms on a better economic footing in competing for leases.

In Table 14,we have explored the relationship between solo-joint bidding and bonus size class. From the point of view of economic theory we would expect to find an increasing use of joint bidding for higher levels of bonus

TABLE 13.

NUMBER OF LEASES IN EACH PROFITABILITY CLASS
BY WINNING FIRM SIZE CLASS
BASED ON ATTRIBUTED SHARES, OBSERVED AND THEORETICAL

Profitability Class of Leases	Firm Size Class[1]						
	Big-8		Big-9-20		Non-Big-20		
	Observed	Theoretical[2]	Observed	Theoretical[2]	Observed	Theoretical[2]	Total
Productive and Profitable	160.31	167.78	74.50	69.09	48.19	46.12	283.00
Productive but not profitable	112.51	108.50	34.61	44.68	35.88	29.83	183.00
Dry	452.28	448.81	189.46	184.81	115.26	123.38	757.00
Total	725.10		298.57		199.33		1,223.00

[1] Firm size class is based on world-wide sales by firm.

[2] Predicted share based upon proportion of total leases falling into each profitability class.

TABLE 14. THE RELATIONSHIP BETWEEN SOLO-JOINT
BIDDING AND BONUS SIZE CLASS
(Number of Leases)

Bonus Size Class	Bid Type				
	Solo		Joint		Total
	Observed	Theoretical	Observed	Theoretical	
$\leq$ \$250,000	265	249.22	89	104.78	354
\$250,001 - \$1,000,000	283	258.37	84	108.63	367
\$1,000,001 - \$3,250,000	186	200.64	99	84.36	285
> \$3,250,000	127	152.77	90	64.23	217
Total	861		362		1,223

bids. This hypothesis is clearly supported by the data. A chi-square test shows significant differences in the frequency of joint bidding by bonus size class size (X_o^2 = 29.60, $X^2_{.95}$ = 7.815).

In Table 15, data have been presented showing the relationship between solo-joint bidding and the number of bidders. If joint bidding reduced the number of bidders, we would expect to observe relatively more joint bidding in one and two bidder sales and relatively less joint bidding where there are larger numbers of bidders. The record shows the opposite results. In one and two bidder sales, the high (winning) bidder is observed to be a solo bidder with greater than the expected frequency. The differences are significant at the 95 percent confidence level (X_o^2 = 16.97, $X^2_{.95}$ = 7.815).[1]

With regard to the use of solo relative to joint bidding in wildcat versus drainage sales, the theoretical relationship is unclear. On one hand, we would expect more joint bidding in wildcat sales on the argument that the risk is relatively high in wildcat sales. On the other hand, an argument can be made that joint bidding should be expected in drainage sales because capital requirements are high. In Table 16, data are presented and the significance of the classification system is tested. We find no significant relationships (X_o^2 = 1.54, $X^2_{.95}$ = 3.841).

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[1]These results may be due to multicollinearity between number of bidders and bonus size class such that where bonus bids are high, (1) joint bidding tends to increase and (2) more bidders compete for the more valuable sales. A stronger evidence of the positive effect of joint bidding on number of bidders (where lease quality is held constant) is given in Appendix 6, Model A, p. 147 below.

TABLE 15. THE RELATIONSHIP BETWEEN SOLO-JOINT BIDDING AND NUMBER OF BIDDERS.

Number of Bidders	Solo		Joint		Total
	Observed	Theoretical	Observed	Theoretical	
One bidder	312	289.35	99	121.65	411
Two bidders	182	172.48	63	72.52	245
3-4 bidders	168	178.82	86	75.18	254
5 or more bidders	199	220.35	114	92.65	313
All leases	861		362		1223

TABLE 16. USE OF SOLO AND JOINT BIDDING PROCEDURES IN WILDCAT AND DRAINAGE BIDDING.

Lease Type	Bidding Form				
	Solo		Joint		Total
	--------- Number ----------				
	Observed	Theoretical	Observed	Theoretical	
Wildcat	766	759.62	313	319.38	1079
Drainage	95	101.38	49	42.62	144
Total	861		362		1223

Trends in Bidding Performance Over Time

Appendix 8,Table 35 provides data on each of the 17 Gulf of Mexico lease sales occurring between 1954 and 1969. Wildcat sales accounted for 9 of these sales. Since the wildcat sales tended to offer more leases per sale, they accounted for 88 percent of the total leases issued in this time period.

Figure 7 shows the ratio of dry leases to all leases issued for wildcat and drainage sales separately. Reasoning from economic principles, one would expect that prospective bidders would nominate and the government would offer the best lease prospects first, leaving the least attractive tracts for later development. On the basis of this argument we would expect to find an upward trend in percent dry for both wildcat and drainage leases. However, there is no significant trend in either sale type. The explanation may be that the early tracts leased were close to shore and in shallow water and that later tracts were in more difficult marine environments but were of equal productive quality.

The average percent dry is significantly higher for wildcat relative to drainage leases. The average percent dry for all wildcat leases is 64.77 percent compared to 40.29 percent for drainage leases. These mean values differ significantly at the 95 percent confidence level.

Figure 8 shows the average number of bidders per lease issued separately for wildcat and drainage leases. There are no significant trends for either sale class and their mean values do not differ significantly.

The ratios of solo to joint winning bids by lease sale for wildcat and drainage sales are shown in Figure 9 . Again, there are no significant trends in either variable and their mean values show no significant difference.

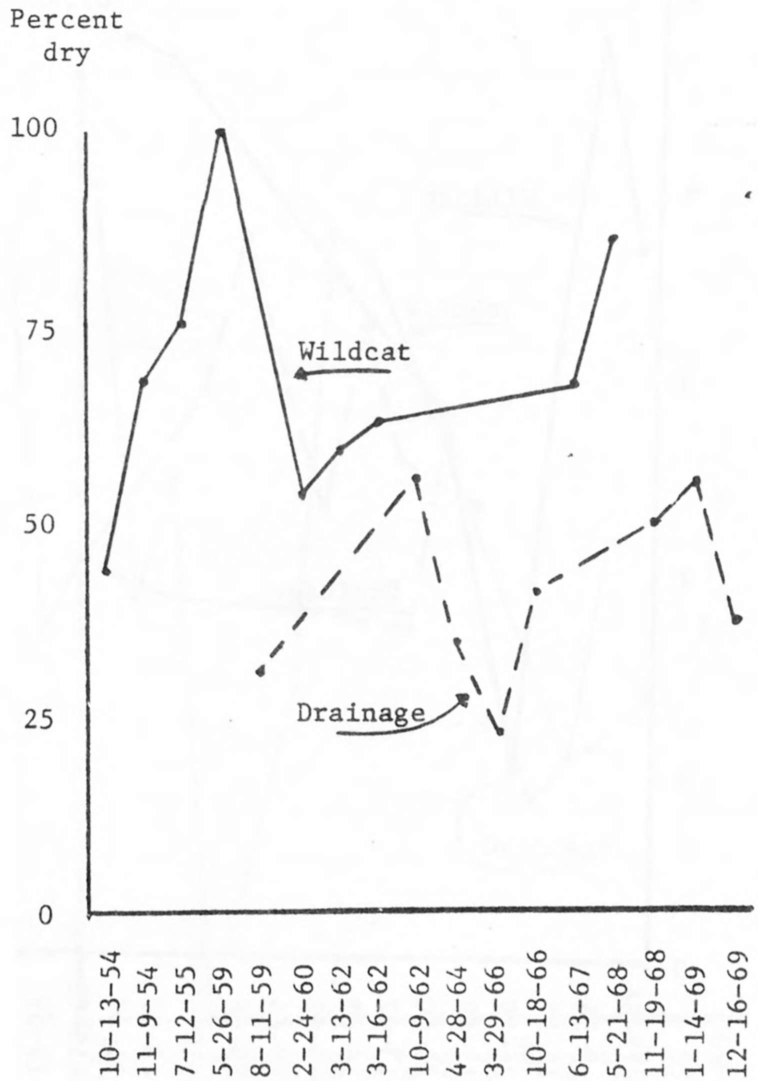

Figure 7--. Dry leases as a percent of total leases issued by lease sale, 1954-1969.

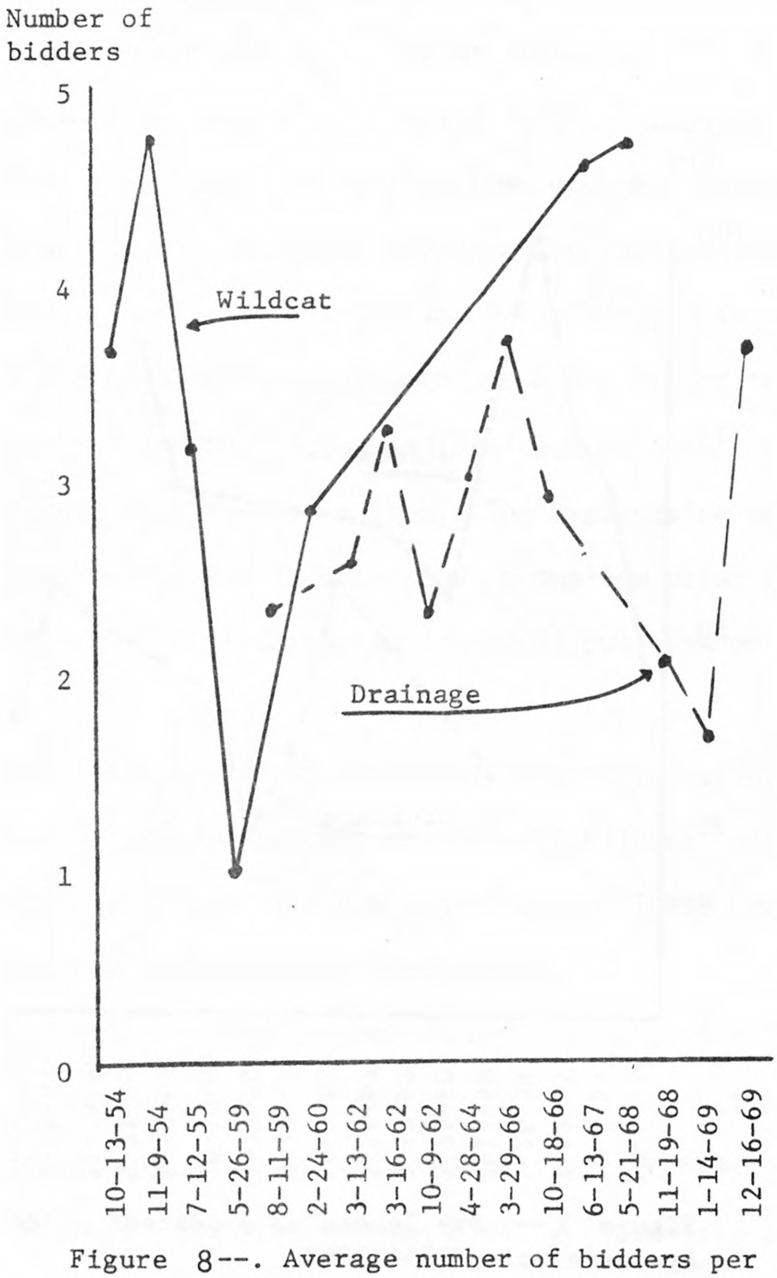

Figure 8--. Average number of bidders per lease issued.

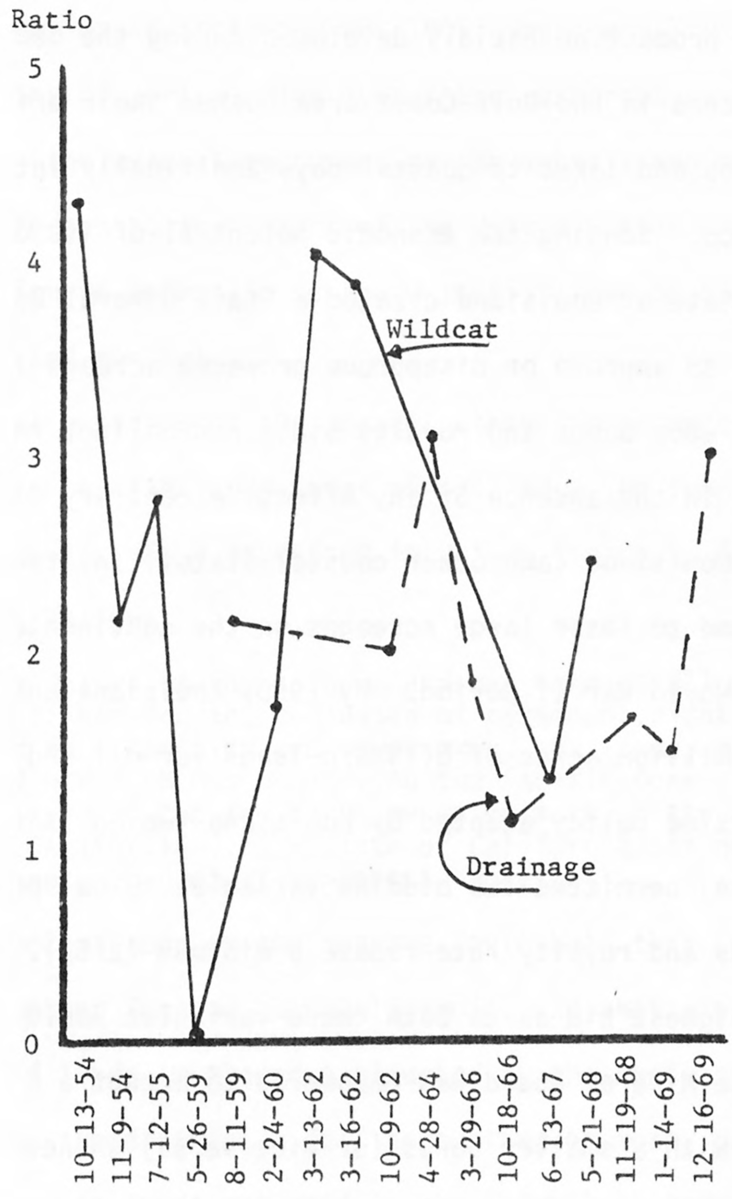

Figure 9 --. Ratio of solo to joint winning bids by lease sale.

II. THE INTERNAL RATE OF RETURN ON INVESTMENTS IN THE "SECTION 6" LEASES ORIGINALLY ISSUED BY THE STATE OF LOUISIANA, 1945-1948.

History

Oil was first produced offshore from a pier located in Summerland, near Santa Barbara, California, at the end of the 19th century. Techniques for deeper-water production rapidly developed during the decades which followed as oil producers in the Gulf Coast area pushed their drilling activities from inland marshes and lakes to coastal bays and finally into the waters of the Gulf of Mexico. Sensing the economic potential of its offshore oil and gas lands, the State of Louisiana created a State Mineral Board in 1936, which was directed to approve or disapprove proposed acreage for leasing, grant leases based upon bonus and royalty bids, and collect revenues from offshore production. In the absence of any effective contrary claim by the federal government, Louisiana (and other coastal states) invited nominations for and then proceeded to lease large acreages on the continental shelf of the U.S. in the post-World War II period. By 1950, Louisiana and Texas had leased almost five million acres of offshore lands for oil and gas development.

The leasing policy adopted by Louisiana (which is still in force today in that state) permitted two bidding variables to be specified for each lease: bonus and royalty rate (above a minimum 12.5%). For any lease offered, the highest bid as to both these variables would be the winning bid; but the State Mineral Board was empowered to accept a higher royalty bid in combination with a smaller bonus (or vice versa) whenever no single bid was highest in terms of both variables. This policy allowed the State Mineral Board a degree of administrative discretion not given to the Bureau of Land Management in the later policy directives under the OCS Lands Act of 1953. Under federal law, the ambiguity of the high bid was avoided by permitting bidding on a single variable, normally the cash bonus.

The claim by Louisiana and other coastal states to offshore resources was always a controversial one, based upon debatable interpretations of common law, implied grants of power to the states in the Constitution, and the absence of any direct contrary claims by the federal government. In an Executive Order dated September 28, 1945, President Truman preempted any possible claims of jurisdiction over these resources by other nations, declaring that "the natural resources of the subsoil and seabed of the continental shelf...contiguous to the coasts of the United States are declared this day by proclamation to appertain to the United States and be subject to its jurisdiction and control..."

The legal position of the coastal states in respect to offshore resources was settled in the Tidelands Cases of 1947-50. The fundamental finding of the Supreme Court, first expressed in <u>United States v. California</u> (June 23, 1947), was as follows:

> The United States is now, and has been at all times pertinent hereto, possessed of paramount rights in, and full dominion and power over, the lands, minerals and other things underlying the Pacific Ocean lying seaward of the ordinary low water mark on the coast of California... The State of California has no title thereto or property interest therein.

Later declarations by the Supreme Court held that Louisiana and Texas stood on no better footing than California, and that since these states had already leased lands in the area affected by the decision and were receiving royalties from those lands, a full accounting of money derived from the area had to be made and funds returned to the federal government.

With the rights of coastal states to any claims upon offshore resources effectively foreclosed, Congress was pressed to enact remedial legislation which would divide offshore lands between state and federal jurisdictions.

This was accomplished in the Submerged Lands Act of 1953, which assigned to the states all title to offshore lands lying within three miles of their coasts (except for Texas and Florida which were later determined to control lands within three marine leagues of their coastlines).

A major complicating factor which was not resolved in the drawing of a state-federal offshore boundary was the status of leases issued by Louisiana and Texas prior to the decisions in the Tidelands Cases. Legal authorities agreed that the leases were null and void. But Congress was shown figures indicating that over $234 million had been spent by oil companies in "good faith" lease bonuses and other investments as of July 15, 1950, and was told:

> The returns from operations thus far conducted on the Continental Shelf area are too meager to offer any real inducement for these operators to continue to operate and to spend their money in drilling new wells and in exploration unless they have some definite assurance that these leases will be confirmed... so I think a complete and clear-cut confirmation of these leases is essential in order to obtain this continued development.[1]

Congress responded to the problem in Section 6 of the OCS Lands Act of 1953. Contracts with the original lessees were honored by the federal government, and their administration was transferred to USGS. Congress required a full accounting of revenues received by Louisiana and Texas from such leases, and instituted a new requirement in all leases that a minimum royalty of 12.5% would apply to all production, whatever the original terms in the state leases. The practical effect of this last requirement, in the case of Louisiana leases, was very small.[2] Indeed, since the OCS Lands Act, Section 9, permitted the federal government to include existing

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[1]Statement by Hines H. Baker, President, Humble Oil Company, Hearings Before the Committee on Interior and Insular Affairs, U.S. Senate, 81st Congress, 2nd session, August 14-19, 1950, p. 86.

[2]All but seven of 271 Louisiana Section 6 leases were bid at 12-1/2% royalty. Only one of these seven leases ever produced. Thus, for practical purposes, the royalty rate on these leases was unaffected by the minimum royalty provision of the OCS Lands Act.

severance taxes as additional royalties on these leases, the actual royalties exceeded the 16-1/2% level which was mandated on OCS leases under the OCS Lands Act of 1953.

Because of the legal uncertainty surrounding the Section 6 leases, lessees had directed their drilling efforts mainly toward delineating underlying structures in the early years following leasing. After federal jurisdiction was established and a firm basis for royalty commitments created, the Louisiana Section 6 leases were rapidly developed. They have included some of the most productive areas in the U.S. offshore.

Rationale for the Present Study

The findings reported in Part I of this report reveal that the internal rate of return on 1954-69 OCS leases was low: 11.43% before taxes. The IRR for the 184 Louisiana OCS leases issued in 1954-55 was even lower: 7.84% before taxes. The 1954-55 Louisiana leases were regarded as good prospects; bidders had acquired a good deal of experience in operating offshore by the time these lease sales were held. What caused the rate of return on these leases to fall so low?

Every lease sale has its unique characteristics of underlying geology, expectations of bidders, etc. Nevertheless, it is possible to find a connection between the Section 6 leasing experience and the later history of Section 8 (OCS) leasing. The most important lesson which can be learned by comparing the Section 6 leases with the 1954-69 OCS leases is the importance of the level of bidding competition in determining the rate of return earned by lessees. This conclusion will be elaborated in the sections which follow.

The Data Base

We have analyzed the profitability of 271 Louisiana Section 6 leases originally leased by the State of Louisiana in the years 1945-48, which were "validated" by the federal government (USGS) in 1953 and operated as federal leases since that time.[1] Our analysis has been conducted in the aggregate since lease-specific data on revenues, royalties, and rental payments on these leases are not available for years after 1950. (Only aggregate production, royalty, and rental figures for all Louisiana Section 6 leases are available from the USGS Royalty Accounting Division.) In most cases, our analysis has duplicated that used in Part I above. Certain differences in the treatment of costs were adopted in order to more closely mirror the historical facts noted in the sections below.

The purpose of the analysis was to estimate the internal rate of return on all Louisiana Section 6 leases, i.e., the solution value for the discount rate, i, which makes the stream of aggregate net revenues from the leases over the years 1945-2010 equal to zero, as in the equation earlier noted (p. 5)

$$\sum_{t=0}^{n} \frac{R_t - C_t}{(1 + i)^t} = 0$$

Production and Gross Revenues

Oil and gas were first produced from these leases in 1948. Gross revenue data for the years 1948-50 were obtained from the State Mineral Board of Louisiana;[2] data for 1953-78 were obtained from USGS Royalty Accounting Division in Reston, Virginia. Gross revenues for 1951 and 1952 were estimated by interpolation. Revenues for years after 1978 were

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[1]We are unable to include Texas Section 6 leases in the analysis because equivalent data relating to bonus costs, revenues, etc. were not available for the 1945-50 period prior to federal takeover.

[2]We acknowledge the generous assistance of Doris Ballard of the Mineral Income Division, Baton Rouge, who compiled much of the Louisiana data.

estimated using the future price forecasts described in Appendix 4. Future production of oil, gas and "other" products was estimated using a constant percentage decline rate method for each type of output, as follows:

$$Q_i = Q_{i-1} \cdot e^{-d}$$

where Q_i represents production in the ith year, e is the base for natural logarithms, and the decline rate, d, is assumed to be 15%.

Exploration Costs

Exploration costs for Section 6 leases were estimated on the basis of the 1950-56 costs developed in our major study. Exploration costs per tract leased in each year listed were assigned as follows:

1945	$100,000
1946	115,000
1947	125,000
1948	135,000

Bonus, Royalty, and Rental Costs

Bonus costs and annual royalty-rental payments for each lease were obtained from the State Mineral Board of Louisiana. Aggregate royalties and rentals for 1953-1978 were obtained from USGS Royalty Accounting Division in Reston. Royalty payments for 1951 and 1952 were determined by interpolating for the effective royalty rate (18.18%), and then applying this royalty rate to the estimated gross revenue for those years. Rental payments for 1951-52 were estimated by simple interpolation.

Drilling Costs

A complete well drilling record for each Section 6 lease through 1977 was developed for us by the USGS Conservation Division in Metarie, Louisiana. To test the accuracy of this record, a sample of leases was selected and the USGS well record for these leases was checked by the Department of Natural

Resources of Louisiana, which maintains a separate record of all wells drilled in state and federal (OCS) waters offshore Louisiana. The USGS well record was verified by officials of the State of Louisiana in all but some insignificant details.

Since the USGS well record was reported on a lease-specific basis, it was necessary for us to aggregate the number of wells drilled in each year. The annual cost of drilling and equipping Section 6 wells was then calculated as the sum (over eleven depth categories) of the number of wells drilled in each depth category each year times the cost per well in that category. The cost per well was assumed to be the average cost for all wells (oil, gas, and dry) in that depth category for that year for the offshore Louisiana area, as reported in the Joint Association Survey of drilling costs (see Appendix 1). Data for years prior to 1955 (the first year JAS data were reported) were estimated by using the average of 1955 and 1956 costs and then deflating using the implicit price deflator for Producers Durable Equipment (1954=100), developed by the U.S. Department of Commerce. Drilling costs for 1957 and 1958 (also not reported by JAS) were estimated by interpolation.

Costs of Equipment Beyond the Christmas Tree

Only initially productive wells require the additional investment implied by this cost category. We estimated the number of initially productive wells by surveying several major oil companies with drilling experience in the Gulf of Mexico in the time period involved. Combining the company estimates, we obtained the following estimates for the percentage of initially productive wells in each time period:

1947-62	72%
1963-69	66%
1970-77	61%

A per-well cost for equipment beyond the christmas tree was assigned to each intially productive well, using the cost estimates of JAS (reported in Appendix 1). For years prior to 1955, the 1955 cost was deflated using the price deflator for Producers Durable Equipment, as noted above.

Operating Costs

Our assignment of operating costs follows the method used for the 1954-69 OCS leases, except for a minor correction. Operating costs are assigned in each year to each currently productive well (CPW), defined as a function of initially productive wells (IPW) and a decline rate which represents the phasing out of some old wells each year. The formula is as follows:

$$CPW_t = IPW_t + (0.93)(CPW_{t-1})$$

The rate at which old wells are carried-over to the succeeding year (0.93) was chosen to most nearly fit the actual record of number of producing wells on Louisiana Section 6 leases in 1978, as reported by USGS Conservation Division. (The rate of well carry-over for the 1954-69 leases was 0.96.)

Marginal Overhead Costs

Overhead expenses relating to bidding, planning, and accounting rise as the number of offshore leases acquired by a company rises. We have estimated marginal overhead costs for each year to be 5% of that year's total costs of drilling and equipping wells, costs of equipment beyond the christmas tree, and operating costs.

Abandonment Costs

The net cash flow for the Section 6 leases in the aggregate remains positive through year 2010, according to our future revenue and cost algorithms. We have cut the net cash flow off in year 2010, then added abandonment costs for all leases in that year, following the abandonment costs estimates given in Appendix 1 . Since our analysis is aggregated, we are underestimating the discounted value for abandonment costs for those leases which would have been abandoned earlier than 2010 and are over-estimating abandonment costs for those leases which will actually survive beyond 2010. We believe the net effect of any resulting bias is extremely small, as can be seen in the tests of sensitivity of our results which are reported below. Any re-distribution of abandonment costs must have a negligible effect on overall IRR since such redistribution would take place in future years and the IRR analysis has the base year 1945.

Results of the Analysis

IRR's for the 271 Section 6 leases are compared to those for the 1223 OCS leases in the table below. In all cases, IRR's are computed using known and estimated revenues and costs from a base year (1945 for the Section 6 leases, 1954 for the OCS leases) through 1978, with future revenues and costs forecasted through 2010, using the forecast methodology described in Appendix 4.

Table 17.

A Comparison of Internal Rates of Return on Section 6 Leases Offshore Louisiana and Section 8 (OCS) Leases in the Gulf of Mexico

	IRR Base Case	IRR Excluding Bonus Costs	IRR Productive Leases Only (Dry Lease Costs Excluded)
271 Section 6 Leases	18.98%[1]	19.50%	20.19%
1223 Section 8 Leases	11.43	19.10	14.88

[1] To test the sensitivity of this result, we have computed IRR's based upon "pessimistic" and "optimistic" adjustments of the net cash flow. For the "pessimistic" adjustment, the net cash flow in each year is reduced by 20% (if positive) or is increased by 20% each year (if negative). For the "optimistic" adjustment, the net cash flow is increased by 20% each year (if positive) and reduced by 20% each year (if negative). The results of these tests are as follows: Pessimistic Adjustment, IRR = 16.37%; Optimistic Adjustment, IRR = 21.74%. It should be noted that the IRR results are quite insensitive to large shifts in costs or revenues, and thus any error in estimated IRR flowing from aggregation of the leases is likely to be very small.

As can be seen, the IRR for the Section 6 leases is far higher than for the Section 8 leases. When dry lease costs are eliminated from the analysis, the IRR's for the two groups of leases converge somewhat, but not enough to provide a sufficient explanation for the divergence in rate of return. The true cause of the divergent results is shown in the IRR's for the two lease aggregates with bonus costs excluded. Here the IRR's are substantially the same, and very near to the rate of return before taxes for all manufacturing corporations in the U.S. for the period 1954-76--19.81%, as reported earlier. This suggests three conclusions.

First, the intense level of bidding in the initial (1954-55) Louisiana OCS lease sales significantly reduced the rate of return on those 184 leases as compared to the IRR earned on the earlier Section 6 leases. Whereas an average of only 1.4 bidders per tract participated in the Section 6 leasing experience, 3.7 bids per tract were received on average for the 1954-55 Louisiana OCS leases (see Appendix 8, Table 35 below). The level of bidding competition in successive OCS lease sales then fell substantially, until 1967. Overall, the average number of bids received for the 1223 Section 8 leases was 3.33--more than twice the average number received for Section 6 leases. The higher bidding intensity in the 1954-69 lease sales provides the most convincing explanation for the difference in rates of return earned.

Second, the Section 6 leases were not inherently more productive than Louisiana Section 8 leases.[1] The reason for the lower IRR on Section 8 leases is not

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[1] 121 of 271 Section 6 leases were productive, or 44.6%, while 466 of 1223 Section 8 leases were productive, or 38.1%. The higher proportion of productive leases among the Section 6 group is explained by the fact that they are all offshore Louisiana leases, whereas the Section 8 leases include Texas and Florida leases, a larger proportion of which were dry. There is no support in these data on relative rates of discovery for the rumor that the Section 6 leases were all "known to be good" because of on-structure drilling prior to lease sale.

that they produced less oil and gas per unit of production cost (in present value terms) but that bidders paid much higher bonuses for leases in federal (OCS) lease auctions than they paid to the State of Louisiana for the Section 6 leases.

Third, there is good reason to believe that the successful bidders in the Section 6 leasing period were the dominant force in the initial OCS lease sales of 1954-55. Eight of the ten largest buyers of Section 6 leases were included among the ten largest buyers of 1954-55 Louisiana OCS leases. Among the most important factors affecting bidding in any lease sale are the known or expected results of the most recent lease sale in the same area. Underbidding in the 1945-48 Section 6 lease sales resulted in high profit expectations for the winning bidders; the result was to encourage much more spirited bidding in the 1954-55 OCS lease sales. As the effects of this over-bidding were communicated throughout the oil industry, a reduced level of bidding competition was recorded in the post-1955 OCS lease sales, with another major correction in the opposite direction then occurring in 1967.

III. REGRESSION ANALYSIS OF HIGH BIDS

The purpose of using regression analysis to evaluate high bids for the leases studied in this report is to explain the observed variability in the high bids in terms of rational bidding behavior as represented by a series of independent variables. Certain policy-related issues will be given special attention. Congress, the Administration, and professional economists have all been concerned about the effectiveness of competition for OCS oil and gas leases. Our regression analysis of high bids will shed additional light on this issue by identifying the effect on high bids of (1) large firms and (2) joint bidders as winning bidders. Another major public policy concern is the efficiency of the bonus bidding system. Our regression analysis will show the effects on high bids of (1) the number of bidders competing for any given lease and (2) the proven productivity of each lease.

Before presenting our findings, we shall discuss some important aspects of modelling bidding behavior in the context of economic theory.

Bidding and Uncertainty

Under the bonus bidding system, firms submit sealed bids for those tracts in a given lease sale which have some economic interest to them. The primary problem facing firms is that the true value of each tract is unknown at the time of bidding. The true value of the tract is the discounted value of the net cash flow associated with the lease. This discounted value corresponds to the maximum bonus the firm would be willing to pay for the lease given no uncertainty about the physical productivity of the lease and future economic conditions. Because 76.9% of the 1223 tracts studied here were dry or unprofitable, the actual high bids on profitable tracts would have had to be below this theoretical "true certainty value" in order for overall returns on all tracts to achieve normality (i.e., to cover the costs of dry and unprofitable tracts).

The desired outcome for a firm trying to maximize returns from a lease is to bid an amount which, first, is not greater than the expected value of the lease and, second, minimizes the difference between its own bid and the second highest bid. These rules allow for cost-coverage on unprofitable leases. The basic difficulty in choosing a high bid is that the expected value of the lease and the size of the second highest bid are unknown at the time of bidding. The firm may, however, engage in information-generating activities in order to reduce its uncertainty in these areas.

To reduce uncertainty about the presence of hydrocarbons, firms engage in presale exploration including geophysical and geological exploration (seismic, gravity and magnetic surveys, plus processing and interpreting the data developed). Firms, in general, are not allowed to do on-structure exploratory drilling prior to the lease sale. Gathering survey data offshore, although somewhat costly, is relatively straightforward. In order to avoid duplication of effort, firms sometimes engage in a "group shoot." A group shoot occurs when a number of firms jointly contract with a single geophysical survey company with all firms sharing in the financing of the exploratory effort and receiving the same data. Even in these cases, however, different interpretations of the data will lead to different expectations regarding the true value of a lease.

Interpretation is the most difficult aspect of tract evaluation. Analysts must attempt both to identify the nature of the underlying geological structure of the tract and to quantify the presence and volume as well as the producibility of any hydrocarbons believed to be present.

In the case of drainage lease sales, important information relating to the geological properties of the lease sale area can be inferred from experience gained on producing leases in neighbouring areas. Thus there will be a large reduction in uncertainty associated with drainage leases as compared with wildcat leases. Whether this information is available to all or only a few firms bidding for drainage leases is a controversial question, but our IRR results tend to support the thesis of limited access to information.

Uncertainty may be further reduced by a strategy of pooling the resource estimates of two or more firms, which then submit a joint bid on the basis of the "pooled" estimate. The combined information of two or more bidders is likely to be more accurate than the information of any of the firms individually.

With respect to the second type of uncertainty (how other bidders will behave), there are legal barriers to communication or coordination. Firms can draw on historical experience when trying to forecast the bid level of others, but there will always be a large amount of uncertainty involved as is evident from the consistently large differences between the highest and the second highest bids ("money left on the table").

Each potential bidder for a given lease has to formulate an estimate of the value of that lease. The value estimate can be conceived of as having been selected at random from a set of possible estimates. Associated with this set of possible estimates is a probability distribution which gives the probability of choosing any estimate in the set. This probability distribution is conditional on (or influenced by) the prior efforts of the potential bidder to ascertain the true value of the lease. Extensive, high quality effort will lead to an increased chance of obtaining a correct estimate of the true value of the lease.[1] Assume that the firm has arrived at an estimate of the true value of the lease through some evaluation process. It is still left with the decision whether to submit a bid or not, and, if it decides to bid, how much it should bid. The value estimate may serve as a guideline for the bid to be submitted, but other factors are also relevant:

i) Past bidding experience. Was an aggressive or cautious bidding strategy more successful?

ii) Cash flow position. How much money can be exposed in the lease sale? What is the optimal allocation of bids between different leases offered at the sale? How is the outcome of the sale likely to affect the firm's future cash-flow?

iv) Other bidders for the lease. How many? Who? How much will they bid? Is it possible to submit a joint bid?

v) The goals of the firm. Is maximum expected profit the goal? Is it trying to avoid risk or is it willing to buy an expensive "lottery ticket" with a small chance of winning a large prize? Is it trying to establish itself in the area? Is the firm willing to pay a very high price for new reserves of domestic oil at this time?

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[1] In more technical terms: an increased probability of obtaining an unbiased estimate with a smaller variance.

No econometric model can fully explain the 1223 highest bids submitted for the leases being studied. The decision on bid-level is too complex, the number of variables involved too subjective, and, for some important variables, data are either not available or the variables are unobservable. Our regression models on high bid are, therefore, much simpler than we would wish them to be. We have had to use a number of proxy variables and dummy variables to capture the influence of important (but unobservable) variables affecting the bidding decision.[1] The variables used in our analysis of the winning bids are discussed below. In addition to these, other variables (and thus other model specifications than those shown below) were tried. These alternative formulations of our regression models are discussed in Appendix 7.

Regression Analysis Variables[2]

1. Log of the number of Bids (LNNBIDS)

In any bidding situation, the highest bid may increase if an additional bid is submitted. It cannot possibly decrease. The intensity of competition for leases (as measured by the number of bidders) will therefore have a positive impact on the high bid over a large number of leases.

Assume that a firm has a positive value estimate for a lease offered for sale. Any bid submitted by the firm will have a higher

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1 A proxy variable is a variable that is closely related to, but not identical to the true variable which affects the choice of bid. A dummy variable is a variable which is set equal to 1 when certain specified conditions are satisfied, zero otherwise.

2 A glossary providing definitions of all regression analysis variables can be found in Appendix 5.

risk of being exceeded by some competing bidder the larger the number of bidders for the lease. The firm is therefore likely to form some estimate of the number of bidders and adjust the bid accordingly in order to arrive at an optimal risk position. As the expected number of bidders goes up, the bid will be adjusted upwards and vice versa. We would expect a positive relationship to exist between the expected number of bidders for a lease (as seen by individual bidders) and the actual number of bidders, particularly over time. Thus number of bidders becomes a proxy variable for perceived competition. This is an additional reason to expect a positive correlation between high bid and the actual number of bidders (LNNBIDS).[1]

2. Log of Present Value of Production (LNPVPDV)

Firms would not engage in presale exploration if this activity did not have a positive value to them in identifying productive tracts. Even the most sophisticated presale exploration is subject to error in interpretation, however, as is seen in the fact that 61.9 percent of the 1223 tracts in this study were found to be dry. Overall, however, we hypothesize a positive correlation between what firms believe to be the worth of a tract (based upon presale exploration) and the ultimate production from the tract.

Ideally one would wish to have data indicating the geological characteristics of tracts, as revealed in presale exploration, in

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[1]See Appendix 6 for a discussion of the extent to which number of bidders is determined by lease quality.

order to formulate a variable to measure "tract quality". Since we have no geological data for the tracts in our study, we are forced to accept proxy variables for "perceived quality", the most important of which is the variable LNPVPDV, as defined below. The rationale for use of this variable is simple. Obviously firms did not know what the ultimate present discounted value of these leases would be at the time of bidding. They did know, however, that certain tracts had more promising geology than other tracts. Since we believe that tracts with more promising geology are, in fact, more productive on average than other tracts, the record of ultimate production value (LNPVPDV) can act as a proxy for perceived value of the tract.

The variable LNPVPDV is defined as the present value of the historical gross production value for each lease through 1978, discounted at 10%. To reduce the bias created by having a longer cash flow record for some leases (1954) than for others (1969), the present value of production figure is used in its log form as the dependent variable. Because most of the leases were dry, the LNPVPDV variable mainly distinguishes between those leases which were productive and those which were dry. The hypothesis of the model is that, on average, firms will pay more for leases which are ultimately proved to be productive and profitable than for productive but unprofitable, or dry leases.

3. Log of the Number of Acres (LNACRES)

In geological evaluation, firms analyze each tract to determine the nature and extent of possible hydrocarbon-bearing rock. For a geological structure of a given thickness, the amount of recoverable hydrocarbons will increase with the horizontal extent of the structure.

Given the thickness of the structure, the larger the area of the tract the larger the expected reserves the tract could contain. Thus, tract size (acreage) should have a positive impact on the size of high bid. (Tracts in our study vary from 50 to 5760 acres.)

4. Log of Water Depth (LNWATDEP)

The amount firms would be willing to bid for a tract depends not only on the expected present value of production but also on the costs of development. We have no direct indicators of anticipated costs of development. However, the water depth of a tract may serve as a proxy for some of the factors that influence the cost of developing and producing oil or gas. Greater water depth means more costly exploratory wells, more costly platforms and more costly development drilling. Greater water depth is also associated with greater distance from shore which implies more costly transportation of men and materials and perhaps larger platforms containing crew housing. As water depth increases (and development costs rise), it would be expected that firms would bid less for a given lease, <u>ceteris paribus</u> (i.e., given the expected reserves).[1]

5. Log of Number of Wells Drilled in 24 Months (LNWELL24)

Because over 60% of the leases in this study were dry leases, and LNPVPDV depends upon actual production, an additional proxy variable for

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[1]We have tested and rejected the hypothesis that water depth is correlated with size of reserves (LNPVPDV) for the leases in our study. Thus there is no reason why firms would pay more for leases located in deeper water.

perceived lease quality is needed. Such a proxy may be discovered by looking at the behavior of firms which have won numerous OCS leases at any particular sale. Simple profit maximization would induce such firms to explore their more promising tracts first. Furthermore, a firm which chose to drill on several tracts simultaneously would be expected to drill more extensively on the tract with the larger *a priori* expectation of finding oil or gas.

These observations lead to the hypothesis that the tracts which are first and most extensively drilled will be those for which lessees had relatively high expectations. Hence a positive relationship between the size of the high bid and the number of exploratory wells drilled on a lease would be expected. USGS data do not differentiate between exploratory and production wells so an arbitrary 24 month time period, beginning at lease date, was selected. During this early period, we expect most wells drilled would be exploratory. We use the log of this number (LNWELL24) to mitigate the bias produced by some production wells that were drilled on very productive tracts in the first 24 months.

6. Drainage versus Wildcat Leases (DWILDDR)

A wildcat tract is one located in an unexplored, undrilled area; substantial uncertainty exists concerning the presence of producible hydrocarbons on such a tract. A drainage tract is located close to a proven deposit; there is less uncertainty about the existence of producible hydrocarbons on the tract. Because of the decreased uncertainty over the existence of hydrocarbons, it would be expected that firms would bid more for drainage than for wildcat tracts.

The dummy variable DWILDDR is set equal to zero for a wildcat lease and one for a drainage lease. A positive coefficient is expected.

7. Large Firms Versus Small Firms (BIG801, etc.)

There has been concern in recent years that large firms have some advantages that enable them to outbid small firms under the bonus bid leasing system, implying that the bonus bid system is not an effectively competitive leasing mechanism. Much attention has been focused on the bonus bid requirement that "front end" money be paid for lease rights. In one form of the argument, large firms are able to pay more for leases than small firms because they have more borrowing power than small firms. An opposite argument has also been suggested by critics of bonus bidding: That large firms, exercising market power, obtain leases at lower prices and therefore pay "less than fair market value" for their leases. Obviously, the question of whether large firms pay consistently more or less in bonuses for their OCS leases has important policy relevance.

In a competitive lease auction market, large firms could consistently outbid other firms and earn a normal or larger rate of return on their OCS leases only if they had special expertise in some aspect of exploration, development or production which decreased their costs or increased their certainty of production. Collusion among large firms to refrain from bidding on certain tracts or to agree on which firm would win what tracts at what prices would be ineffective without some mechanism to prevent firms that were not members of a collusive agreement from entering higher (competitive) bids.

Under competitive conditions and in the absence of the "special expertise" described above, there is no reason to expect the winning bids of large firms to be consistently higher (or lower) than those of other firms. The hypothesis of no significant relationship between high bid and firm size has been evaluated two ways. First, the impact of large firm bidding was evaluated using a dummy variable (BIG801). This variable is set equal to 1 when the winning bidder is one of the 8 largest firms. In the case of joint bids, BIG801 is set equal to 1 if any of the winning bidders is a BIG8 firm. If these conditions are not satisfied, the dummy variable is set equal to zero. The second set of variables measuring the impact of BIG8 on high bid are discussed below and involve the simultaneous impact of jointness, firm size and the drainage/wildcat distinction.

8. Joint Versus Solo Leases (JOINT01, etc.)

Two sets of hypotheses are suggested for the impact of joint bidding on high bid. The first is concerned with information and risk. For a group of firms to bid together, there must be general agreement about the expected value of the tract. Without general agreement, the joint bid could not be mutually agreed upon. When a number of firms do independent tract evaluations and get consistent results there is less uncertainty about the true value of the tract than when the firms get widely divergent evaluations. Firms should be willing to submit a larger bid for a tract where expectation of production is less uncertain. Furthermore, if there is a constraint on capital available to the firm, joint bidding will permit the firm to bid for a larger number of leases. The associated risk spreading should also lead to an increase in the amount bid. Therefore winning bids submitted by joint ventures would tend to be larger than winning solo bids.

A second hypothesis is concerned with the effect of joint bidding on competition via the number of bidders. Joint bidding might reduce the average number of bidders by removing some potential independent bids. But it may also increase the number of bids received (1) by permitting small firms to participate in bidding, and (2) by reducing overall risk for firms which are able to pool their bids over numerous trusts. Thus, two firms bidding jointly may individually be involved in more than twice the tracts bid on, relative to solo bidding.

We have not evaluated the overall effect of joint bidding on competition for leases. We hypothesize that information pooling and risk spreading will combine to produce a net positive relationship between joint bidding and high bid. We cannot exclude the possibility that higher-than-average valued tracts will receive a higher proportion of joint bids. We have attempted in our regression model to measure "perceived value of the tract" through three proxy variables (LNPVPDV, LNWELL24, and LNACRES). If this is a proper specification, the effect of tract quality on high bid should already be captured in these variables. The effects of joint bidding can, thus, be largely distinguished from the effects produced by differences in tract quality.

10. Simultaneous Characteristics: Firm Size, Joint/Solo and Drainage/Wildcat

Preliminary analysis has indicated that there might be complex interactions in bidding involving the simultaneous characteristics of firm size, joint/solo and drainage/wildcat attributes. Any systematic bidding characteristics involving these three factors simultaneously can be captured by defining a set of variables that differentiates between relevant combinations of these effects. The following table gives the dummy variables developed for this purpose:

Simultaneous Characteristics Dummy Variables

	Wildcat		Drainage	
	Solo	Joint	Solo	Joint
Non-Big-8 Firms	NB8WS*	NB8WJ	NB8DS	NB8DJ
Big-8 Firms	B8WS	B8WJ	B8DS	B8DJ

*Base Case

To understand the use of the dummy variables above, note that whenever an observation in the regression involves a Big-8/wildcat/solo lease, B8WS is set equal to 1 while all other dummy variables are set equal to zero. Of the eight cases in the table above, one (called the base case) must be omitted in the regression equation.[1] Leases which fall into the other seven categories are then, by implication, compared to leases falling into the base case category. The coefficients estimated for the seven dummy variables indicate any systematic differences between the size of winning bids of the base case type and winning bids of each of the seven other types of leases listed in the table above.

11. Sale Specific Characteristics (S550712, etc.)

The regression analysis is based on 1223 leases sold in 17 lease sales held over the years 1954-1969. We hypothesize that expectations of bidders, underlying geology, regulatory constraints, and general economic conditions will differ from sale to sale. To measure the

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[1] See J. Johnston, Econometric Methods, 2nd ed., McGraw-Hill, 1972, pp. 178-180.

effects on high bids of influences which are lease-sale specific, fifteen dummy variables for the lease sales between 1955 and 1969 have been included. The base case for these dummy variables is 1954 (two lease sales). Coefficients on the dummy variables should be interpreted as relative to 1954 sales.

Results of Regression Analysis of Log of High Bid (LNHIGHBD)

Models 1-3 are the most satisfactory of the estimated equations on high bid. They all have in common a good ability to explain variation in the dependent variable (a high R^2) as well as mostly significant independent variables, all significant variables having the expected sign for their coefficients. The three models are discussed successively.[1]

Model 1.

All coefficients, except the dummy variable BIG80T, are significant. The sign of the coefficient of LNNBIDS is positive and significant. These findings strongly support the hypothesis that number of bidders competing is a major determinant of the amount of bonus the federal government will collect. Policies aimed at increasing the number of bidders participating in lease sales are therefore consistent

[1]No discussion of the distribution of the error terms is included. We have plotted the error terms against the dependent variable, tested for normality in the distribution of the error terms as well as tested for heteroscedasticity. There do not appear to be any problems involved which can alter the validity of the reported models or the conclusions to be drawn from them.

with the goal of increasing the federal share of OCS revenues.[1] The perceived economic quality of a lease, as measured by the proxy variables LNPVPDV, LNACRES and LNWELL24, also has a positive and significant influence on high bid, as expected. Furthermore, the sign and significance of LNPVPDV is also evidence of rationality on the part of the bidders. More productive leases receive higher bids. One can draw the conclusion that bidders under the bonus bidding leasing procedure <u>do</u> have information prior to bidding which, on average, enables them to distinguish between more and less productive leases and bid accordingly. There is always an element of chance in the bidding for a particular lease, but for a large number of leases this element becomes less important and the winning bids tend to vary in the same direction as the productivity of the leases.

The coefficient of water depth (LNWATDEP) is negative and significant which is consistent with our prior expectations. Greater water depth implies larger prospective costs of platforms, pipeline distances, etc. The results confirm that firms bid less for leases having higher prospective costs.

The wildcat-drainage dummy variable (DWILDDR) is positive and significant, supporting the contention that higher expected value and/or lower risk associated with drainage leases results in higher winning bids than for wildcat leases.

In terms of policy implications, an important finding in this

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[1] It should be noted again, as in our discussion of the IRR results (Part I, above), that the federal government's share of OCS revenues for the 1223 leases studied here was <u>above</u> that which would have been expected given a normal, competitive return to the lessees. Bidding intensity for these leases was, therefore, very high.

model is that the explanatory variable JOINT01 has a positive and significant impact on the winning bid. This result indicates that a joint winning bid will increase the high bid relative to a solo winning bid. It does not support an "anti-competitive" hypothesis for the impact of joint bidding; it is consistent with a hypothesis emphasizing the advantages to the government of risk and information sharing through joint bidding.

Our results indicate that it does not make any significant difference whether a bid is won by a Big-8 firm. The coefficient of BIG801 is negative but insignificant at the 5% level. We hypothesized that no differences in winning bid levels between Big-8 firms and non-Big-8 firms would be observed in a competitive lease market. This finding has important policy implications. It does not support the opposing contentions that (1) large firms have unfair advantages which enable them to outbid small firms, or (2) large firms have market power which enables them to obtain leases at lower prices than small firms. There is no significant relationship between firm size and high bid.

Models 2 and 3 are extensions of Model 1. In the discussion of these models, variables which are included in Model 1 and also in Model 2 or Model 3 will not be referred to again unless there is a change in the sign of the coefficient or the significance level which might alter any of the previously-stated conclusions.

Model 2

In Model 2 the dummy variables BIG801, JOINT01 and DWILDDR have been replaced with eight variables that describe a lease by three characteristics simultaneously: Size of winning firm, joint/solo, and drainage/wildcat. As a result, the explanatory power of the model is higher (R^2 has increased). When interpreting the coefficients of these interaction variables, it should be kept in mind that the base case for Model 2 (where all these dummy variables are set equal to zero) is non-Big-8/wildcat/solo leases (NB8WS) and the other lease categories are being compared to this base case.

Model 2 does not give any information about the possible differences between, say, B8DS and NB8DS leases. In order to detect such differences, Table 18 was developed. Table 18 points out the significant findings of Model 2, and should be thought of as a simple summary of the information contained in Table 19.[1]

Three basic comparisons are noted in Table 18, testing the significance of three distinguishing pairs of characteristics of the leases in our study: (1) firm size (Big-8 vs. non-Big-8); (2) sale type (wildcat vs. drainage); and (3) form of bidding (joint vs. solo).

Model 2 confirms and reinforces the finding of Model 1 that firm size has no significant effect on high bid. Big-8 firms pay neither consistently more nor less than Non-Big-8 firms in winning bids for any of the four types of leases studied here: Joint/wildcat (JW), solo/wildcat (SW), joint/drainage (JD), and solo/drainage (SD).

Model 2 also confirms and strengthens the finding that drainage leases receive significantly higher bids than wildcat leases, whether the winning bidders are Big-8 or Non-Big-8 and whatever the form of

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[1]Table 19 was developed by running Model 2 eight times, once for each possible base case. The R^2 and the sign and significance of all variables other than those shown in this table remain unchanged for these eight runs.

bidding (joint or solo).

Table 18.

Tests of Significance of Differences between High Bids

Case 1. Comparison by size of firm. (Big-8 vs. Non-Big-8)	Type of Lease			
	JW	SW	JD	SD
	*	*	*	*

Case 2. Comparison by type of sale. (Wildcat vs. Drainage)	Type of Lease			
	B8J	B8S	NB8J	NB8S
	**	**	**	**

Case 3. Comparison by form of bidding. (Joint vs. Solo)	Type of Lease			
	B8W	B8D	NB8W	NB8D
	*	***	*	*

* No significant difference between high bids.

** Drainage bids are significantly higher than wildcat bids.

*** Joint bids are significantly higher than solo bids.

Note: To interpret the findings reported in Table 18, consider the single asterisks for Case 1. These mean that there is no significant difference between the high (winning) bids submitted by Big-8 firms as compared to Non-Big-8 firms for joint/wildcat (or JW) leases, and so on for the other lease categories.

The most important finding of Model 2 is shown in Case 3, above. Model 1 has shown that joint bidders paid significantly higher bonuses than solo bidders. Model 2 shows that the true significance of joint bidding is confined to one sub-category of leases: Big-8/drainage leases. For the other three sub-categories (Big 8/wildcat, non-Big-8/wildcat, and non-Big-8/drainage) there is no significant difference between the high bids of joint bidders and those of solo bidders. It is thus evident that for all wildcat leases--and these comprise 88% of the leases in our study--the high bid is not significantly affected by the form of bidding (joint vs. solo). We must therefore re-state our earlier finding from Model 1 as follows: Joint bidders paid significantly more in bonus bids for leases than solo bidders, but the positive impact of joint bidding is confined to only one sub-category of leases, Big 8/drainage leases. Only for drainage leases, and only when one or more of the (joint) winning bidders was a Big-8 firm did the information and risk-reduction advantages of joint bidding lead to significantly higher bonus bids than for solo-bid leases.

<u>Model 3</u>

Model 3 is also an extension of Model 1. DWILDDR has been deleted. Instead we have added a dummy variable for each lease sale, identified by year, day, and month (e.g. S550712).

Model 3 is the model with the largest explanatory power (highest R^2). In Model 3, the intercept term is not significantly different from zero and LNWATDEP has become insignificant, probably because water depth is implicitly associated with different lease sales.

The base case for the sale dummy variables is defined to be 1954 (two wildcat sales). The effect of the sale dummy variables on high bid should be evaluated relative to this base case. All the drainage sales except the one on 12-16-69 yielded high bids which were significantly higher than the 1954 wildcat base sales. This result is consistent with our Model 1 findings. Because the base case was made up of wildcat sales, the other wildcat sales are a mixture of non-significant differences, significantly higher, and significantly lower bid sales. Of greatest importance, there is no linear time trend in the high bid. The coefficients of the sale dummies do not show an increase (or decrease) for each sale. Some coefficients are negative, some positive and there is no apparent pattern of stepping up (or down) of the coefficients. Presumably, the sale date dummy variables capture a number of factors which are specific to each sale, most importantly past history, current market conditions, current and expected government control conditions, and the general state of bidders' expectations as to future economic conditions. In this interpretation, it can be seen that these factors are variable over time and that they have an important impact on the winning bid.

Summary of Regression Analysis of High Bids

Number of bidders (LNNBIDS) was found to have a positive and significant influence on the high-bid in all models. This is consistent with our hypothesis that the extent of competition for a lease is a major determinant of the amount of bonus the government can collect from oil and gas leases.

Perceived Quality of a Lease (LNPVDPV, LNACRES, LNWELL24) also has a positive and significant impact on the high bid. This implies that bidders are willing to bid more for a lease with a higher perceived value, which is consistent with our prior expectations. Furthermore, the positive relationship between high bid and LNPVPDV shows that winning bidders, on average, are able to distinguish between more and less productive leases prior to bidding.

Perceived Costs of Drilling, Development and Production (LNWATDEP) has a negative impact on the amount of high bid, as expected.

Firm Size (BIG801). Our hypotheses relating firm size of winning bidder and the high bid are supported by the regression analysis. Alleged anti-competitive effects from a high "front end" payment, market power of larger firms or collusive behavior between larger firms are not supported by the record. The findings from both the regression analysis and the IRR analysis in Part I are that the lease market is competitive and there is no systematic bias favoring large firms (defined as the Big-8 oil companies).

Joint vs. Solo Leases (JOINT01). Joint winning bids are significantly higher than solo winning bids in the case of Big-8 drainage leases. There are no significant differences for wildcat leases or non-Big-8 leases. Anti-competitive effects of joint bidding can therefore not be supported by our models. Furthermore, information sharing and risk spreading advantages of joint bidding are relevant only in the case of drainage leases.

Drainage vs. Wildcat Leases (DWILDDR). Drainage leases are shown to have significantly higher winning bids than wildcat leases. This is consistent with our hypothesis concerning the higher expected value and lower risk of drainage leases relative to wildcat leases.

Sale Specific Characteristics. Each lease sale has characteristics which make it different from any other sale. The expectations of bidders, current and proposed government regulations and economic conditions in general, as reflected in our lease sale dummy variables, have an important impact on the size of high bid.

MODEL 1

DEPENDENT VARIABLE: LOG. OF HIGH BID. 1223 LEASES.

R^2= .6697

DEP.VAR. : LNHIGHBD

VARIABLE	PARAMETER ESTIMATE	T-RATIO
INTERCEPT	6.864577	14.0020*
LNNBIDS	1.161876	32.6184*
LNPVPDV	0.008555141	2.2270*
LNACRES	0.652809	10.7795*
LNWATDEP	-0.080496	-2.0749*
LNWELL24	0.585456	13.6081*
JOINT01	0.164823	2.9020*
BIG801	-0.024749	-0.4456
DWILDDR	1.117831	11.4042*

*significant at 5% level (two tailed test)

MODEL 2

DEPENDENT VARIABLE: LOG. OF HIGH BID. 1223 LEASES.

R^2 = .6714

DEP VAR: LNHIGHBD

VARIABLE	PARAMETER ESTIMATE	T RATIO
INTERCEPT	6.890060	14.0136*
LNNBIDS	1.167924	32.6057*
LNPVPDV	0.007890559	2.0506*
LNACRES	0.655312	10.7942*
LNWATDEP	-0.085417	-2.1928*
LNWELL24	0.586604	13.5671*
B8WS	-0.045778	-0.6843
B8WJ	0.077168	0.9846
B8DS	1.007345	7.6268*
B8DJ	1.494556	9.3684*
NB8WJ	0.118190	0.9843
NB8DS	0.857877	4.4152*
NB8DJ	1.227305	4.0443*

*Significant at 5% level (two tailed test)

Omitted dummy variable: Non-Big-8/wildcat/solo leases (NB8WS)

TABLE 19.

T-RATIOS FOR COEFFICIENTS OF INTERACTION VARIABLES IN

MODEL 2 (HIGH BID) WITH VARYING BASE CASE

		B8WS	B8WJ	B8DS	B8DJ	NB8WS	NB8WJ	NB8DS	NB8DJ
1.	B8WS		(1.75)	(8.18)*	(9.81)*	(.68)	(1.43)	(4.69)*	(4.22)*
2.	B8WJ	(-1.75)		(6.81)*	(8.67)*	(- .98)	(0.34)	(3.94)*	(3.77)*
3.	B8DS	(-8.18)*	(-6.81)*		(2.76)*	(-7.63)*	(-5.49)*	(- .72)	(.70)
4.	B8DJ	(-9.81)*	(-8.67)*	(-2.76)*		(-9.37)*	(-7.44)*	(-2.79)*	(- .81)
5.	NB8WS	(- .68)	(.98)	(7.63)*	(9.37)*		(.98)	(4.42)*	(4.04)*
6.	NB8WJ	(-1.43)	(- .34)	(5.49)*	(7.44)*	(- .98)		(3.42)*	(3.49)*
7.	NB8DS	(-4.69)*	(-3.94)*	(.72)	(2.79)*	(-4.42)*	(-3.42*		(1.07)
8.	NB8DJ	(-4.22)*	(-3.77)*	(- .70)	(.81)	(-4.04)*	(-3.49)*	(-1.07)	

Notes:

i) Each row represents a base case; row 5 is the base case used in Model 2. T-values are given for differences of coefficients between the base case variable and the variable at the top of each row. A positive t-value implies that leases in the column category had larger LNHIGHBD values than leases in the base case (row) category, and conversely for negative t-values.

ii) An asterisk indicates that the difference between the column and the row entry is significant at the 5% level (two tailed test).

iii) When interpreting the table, the reader should keep in mind that if our proxy variables for perceived quality of the lease are appropriately specified, the perceived quality of the lease will not affect the conclusions to be drawn from the table. The tests above can be thought of as having been performed for a constant perception of quality where the only relevant distinctions are firm size, solo or joint winning bid and whether the lease is wildcat or drainage. The tests shown in the table are methodologically superior to a straight-forward test of the differences in mean high bids for the relevant categories since the latter does not take into account differences in the perceived quality of the leases or other independent variables included in the regression equation.

MODEL 3

DEPENDENT VARIABLE: LOG OF HIGH BID. 1223 LEASES

R^2 = .7132

VARIABLE	PARAMETER ESTIMATE	T RATIO
INTERCEPT	6.247047	12.0395*
LNNBIDS	1.076909	30.6921*
LNPVPDV	0.015016	3.9869*
LNACRES	0.702480	11.2946*
LNWATDEP	-0.040678	-1.0016
LNWELL24	0.504140	12.0193*
JOINT01	0.160847	2.8992*
BIG801	0.079816	1.4774
S550712 (W)[1]	-0.157644	-1.4068
S590526 (W)	-1.169066	-5.7347*
S590811 (D)	1.664311	7.5352*
S600224 (W)	0.177422	1.6424
S620313 (W)	-0.192810	-1.8537
S620316 (W)	-0.140883	-1.3772
S621009 (D)	1.562751	5.2144*
S640428 (D)	0.847515	4.0325*
S660329 (D)	1.291077	5.6746*
S661018 (D)	0.964264	5.0293*
S670613 (W)	0.311363	2.8338*
S680521 (W)	0.636131	5.3575*
S681119 (D)	2.049458	8.7342*
S690114 (D)	1.238221	5.8201*
S691216 (D)	0.442346	1.9405

*Significant at the 5% level (two tailed test)

[1] Sale dated 7/12/55, wildcat.

IV. REGRESSION ANALYSIS OF EXPEDITIOUS DEVELOPMENT

Buyers of OCS oil and gas leases have been encouraged through the force of federal law and policy to develop oil and gas production "expeditiously". Both the language of the 1953 OCS Lands Act (in particular the five-year lease term) and the policy position of USGS have been directed toward encouraging early drilling of leases and early field development of discoveries. Since the Arab oil embargo of 1973, these pressures for rapid development of leases have been intensified, and the 1978 Amendments to the OCS Lands Act spelled out in even more explicit fashion the position of Congress: that expeditious development is a major goal of federal policy in regard to the OCS.

If oil or gas have been discovered on a lease in economic quantities, if pipelines and other production facilities are available, and if there are no legal or environmental barriers to production, then the decision by a lessee to withhold production from the lease may be described as "non-expeditious development". Few cases of delayed production are this clear-cut, however, and thus it is generally true that the fact (or absence) of "expeditious development" is not simple to determine. Furthermore, there is a legitimate question as to whether society is better off if leaseholders are pressed, through the force of law or policy, to increase the speed of lease development beyond that which a private firm would voluntarily choose.Economic theory predicts that, in general, lessees will choose a rate of lease development that equals or exceeds that which is socially optimal, even in the absence of government policies directed toward this goal. Thus, it may not be necessary to invoke any special pressures in this direction, at least under the conventional bonus bid leasing system which characterized OCS leasing in the period under study here.

The purpose of our study of expeditious development is to provide an empirical test of the hypothesis that expeditious development is not significantly affected by size of firm (Big-8 vs. non-Big-8) or by the form of bidding (joint vs. solo). We will define expeditious development three different ways: by number of wells drilled in the initiated 24 months after lease sale; by time to first production; and by time to maximum production. These last two measures will be tested separately for oil leases and for gas leases. Before presenting our empirical findings, we will give a brief overview of the theory underlying the optimal rate of exploitation of an exhaustible resource over time.

Theory of Optimal Rate of Exploitation

The fundamental principles underlying the theory of optimal rate of exploitation of an exhaustible resource such as crude oil or natural gas were stated in a seminal article by Harold Hotelling in 1931.[1] Hotelling argued that competitive firms can be relied upon to choose a time-path for production of a non-renewable resource which is socially optimal, given a certain set of assumptions. These assumptions would be violated in the following major cases:

(1) The resource has the characteristic of common property.

(2) The resource is controlled by a monopoly, or by firms that have monopoly power.

(3) Private risk exceeds social risk (or the private discount rate exceeds the social discount rate).

(4) Resource prices are controlled and price controls are subject to substantial uncertainty.

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[1]"The Economics of Exhaustible Resources," J. Polit. Econ., April 1931, pp. 137-75.

Under conditions of common property in oil and gas resources, a rush to production by firms sharing common interests in a particular structure could ultimately reduce the socially optimal yield from the resource. This problem is solved by unitization of OCS leases, as enforced by USGS.

Under conditions of monopoly, producers would rationally choose to delay production of oil or gas. The question of monopoly power in markets for crude oil and natural gas has been much debated, but the consensus of economists is that no single U.S. producer of oil or gas has any significant market power. The U.S. Federal Trade Commission concluded (in 1972) that Big-4 and Big-8, concentration ratios in all aspects of U.S. oil production have not been at a level sufficient to create a problem of oligopolistic interdependence in fixing production levels since World war II.[1] Proof of this conclusion is given in the fact that government policy had to be invoked (in the form of market demand prorationing regulations) to reduce the production of crude oil below the level which would voluntarily have been chosen by producers over the years. This policy, introduced in the mid-1930's, became ineffective in 1972.

There are various arguments asserting that private risk exceeds social risk in natural resource development, or that the private discount rates applied to future (expected) oil or gas production are higher than social discount rates. The effect of this disparity in private vs. social discount rates, if it exists, is to create an incentive for private firms to produce oil or gas too quickly (since from the point-of-view of the firm, the value of current income exceeds that of future income in a ratio greater than that for society). Thus, the need for government intervention to insure

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[1]See R. Jones, W. Mead, and P. Sorensen, "Free Entry into Crude Oil and Gas Production and Competition in the U.S. Oil Industry," Natural Resources Journal, October 1978, p. 875.

expeditious development of leases is greatly reduced or eliminated where private discount rates exceed social discount rates.

The final case in which a contradiction may exist concerning Hotelling's conclusion that competitive firms will not seek a rate of natural resource production below that which is optimal for society involves government price fixing. Price regulation is, in itself, a violation of the model of competition in markets so it is not surprising that this condition may upset the outcome predicted by Hotelling. If prices are regulated and stable at a level below market-clearing prices, then rate of output may be either greater or less than would be expected in a competitive market, depending upon the relationship between the regulated price and marginal costs of extraction. If prices are regulated and unstable (with an uncertain expectation that regulated price will be raised) there will be an incentive to withhold output from the market, and the incentive will be greater as the probability of large price increases rises. This situation may, indeed have faced some oil and gas producers in the U.S. since 1973. It is possible that government price regulations since 1973 have created enough uncertainty about future prices that some form of legal pressure would be needed to maintain production of oil and gas from OCS leases at the optimal level (or to achieve expeditious development of new leases).

Since the unsettling effects of uncertain price controls in production would not have been felt by lessees in our study until a fairly late period in the life of most leases (except for those issued in 1969), we could not expect this factor alone to undercut other incentives for expeditious development. In general then, our prediction from economic theory would be that leases would be developed at a speed not below the socially optimal rate in the absence of a government rule mandating expeditious development.

Limitations of the Analysis

An ideal measure of expeditious development would have to consider a large and technically complex set of data for each lease, embracing geology, engineering, reservoir modelling and a whole set of technical and economic constraints. The difficulty of this type of lease-specific analysis is suggested by the growth in MER-related literature over the past decade, typified by studies conducted by the Los Alamos Scientific Laboratory. (See, for example, LA-6533-MS, October 1976, where six different definitions of MER are discussed and evaluated, using a fairly simple gas-water reservoir model.)

Given the complexity of the analysis required to determine the pattern of development which would be optimal for an individual lease, and the fact that the data required for such an analysis are not available to us, we have attempted to measure the presence or absence of expeditious development only for groups of leases (Big-8, non-Big-8, etc.) and only in terms of some simple, indicative measures of speed of drilling and production. We have used the same types of ordinary least squares (OLS) regression models as were reported in Part III (above) to test the significance of various independent variables in affecting the speed of lease development. The variables used in these models are, in general, the same as those used in our earlier regression analysis of high bids. The results will be reported in the sections which follow.

Speed of Exploratory Drilling

To measure speed of exploratory drilling, we might have determined the average time required to achieve certain mileposts for various classes of lessees; i.e. time to first well, time to first five wells, etc. But there is a certain arbitrariness in this measure; that is, why is the first well important? Why five wells and not six? This problem can be avoided by framing the question in terms of the absolute number of wells drilled within a given time period. This period should be short enough to distinguish exploratory from development drilling and long enough to allow for some random delays in getting a drilling program started. Discussions with managers of oil company drilling programs led us to choose a time period of 24 months as appropriate for this purpose. We have used number of wells drilled within 24 months of lease sale in log form as our dependent variable (LNWELL24) to avoid statistical problems with outlyers created by a very few leases which were heavily drilled. Since most of the wells drilled on outlyer leases were production wells, conversion of number of wells into LNWELL24 allows the dependent variable to more accurately measure diligence in exploration. (Expeditious production is measured by four other variables, as reported below.)

Regression results for our analysis of speed of exploration are reported in Models 4A and 4B. These models are similar to Models 1 and 2 (Part III, above) except that LNWELL24 replaces LNHIGHBD as the dependent variable and LNBONPA (log of bonus per acre) replaces LNPVPDV among the independent variables. In addition, a new dummy variable, PROD01, is included to distinguish productive leases from dry leases. LNBONPA and PROD01 are used as proxies for perceived lease quality. This follows the reasoning presented earlier which argued that bidding is fundamentally rational -- that is, leases which are perceived to have a higher probability of being productive are, in fact, more likely to be productive. We hypothesize that such leases will be explored earlier and more fully than other leases.

Expected costs of developing leases should also influence the timing of exploratory drilling. For leases of the same quality (extent of recoverable hydrocarbons) those leases in deeper water would probably be drilled later. This element of differential cost is measured by the variable LNWATDEP, as before. Finally, a dummy variable, DSTATE, is used to distinguish offshore Texas and Florida leases from offshore Louisiana leases. The DSTATE variable should measure some differences in expected lease quality or costs which are not captured by other independent variables, in particular LNBONPA and PROD01.

Regression Results for Speed of Exploratory Drilling

Regression results relating variations in LNWELL24 (log of the number of wells drilled on each lease in the first 24 months following lease sale) to variations in our exploratory variables are reported in Models 4A and 4B.

In Model 4A, three dummy variables are used to distinguish leases by size of firm, type of winning bid, and type of acreage being offered. The regression results show all three dummy variables to be significant at the 5 percent level. That is, Big-8 firms drilled more exploratory wells than non-Big-8 firms, solo bidders drilled more than joint bidders, and drainage leases were drilled more than wildcat leases. In addition, the two variables measuring lease quality (LNBONPA and PROD01) were highly significant, indicating that leases which are perceived to have higher potential for production are drilled earlier, and more extensively than other leases. Year of lease sale (YOS) is also significant. This means that exploration activity was significantly speeded up over the lease sale years from 1954 to 1969, possibly reflecting improvements in technology, the increasing availability of offshore drilling equipment, and the operation of the learning curve. Neither of the proxies for relative cost of production was significant (LNWATDEP and DSTATE). These differences in expected costs may have already been captured in differences in high bids (LNBONPA). The explanatory power of Model 4A is respectable: R^2 = .4143. Table 20 reports the average (mean) values for number of wells drilled within 24 months for all leases and for the major lease categories. These are log values. The arithmetic mean value of the observations is 1.44 wells for all leases, but ranges from 0.93 for non-Big-8 leases to 1.68 for Big-8 leases; from 1.01 for wildcat leases to 4.73 for drainage leases; and from 1.41 for solo leases to 1.53 for joint leases.

To further investigate the meaning of our finding that the three dummy variables BIG801, JOINT01, and DWILDDR are significant, we ran regression model 4B, which is identical to 4A except for conversion of these three dummy variables into their eight components. These eight interaction variables represent sub-categories of the original three variables.

Except for the coefficients on the interaction variables, the results of Model 4B closely parallel those noted above. As was true for Model 2 (Part III, above), it is possible to run Model 4B only if one of the eight interaction variables is used as a base case. We have estimated the regression for the situation where NB8WS is the base case as Model 4B. To give a comprehensive picture of the results of Model 4B, however, it is necessary to refer to Table 21, where all eight interaction variables

MODEL 4A.

DEPENDENT VARIABLE: LOG. OF NUMBER OF WELLS DRILLED IN THE FIRST 24 MONTHS FOLLOWING SALE DATE. 1223 LEASES.

R^2 = .4143

DEP. VAR: LNWELL24

VARIABLE	PARAMETER ESTIMATE	T-RATIO
INTERCEPT	-1.056281	-8.3906*
LNBONPA	0.197978	16.4741*
YOS	0.025350	6.0586*
LNWATDEP	0.026362	1.0274
DSTATE	-0.076773	-1.7494
PROD01	0.380563	10.4832*
BIG801	0.118210	3.3380*
JOINT01	-0.092775	-2.5828*
DWILDDR	0.156257	2.6254*

* Significant at the 5% level (two-tailed test)

Table 20.

MEAN VALUES OF DEPENDENT VARIABLES
FOR FIVE MEASURES OF EXPEDITIOUS
DEVELOPMENT

Dependent Variable	Mean of Dependent Variable	Mean Value of Dependent Variable for: Big 8	Non-Big 8	Wildcat	Drainage	Solo	Joint
LNWELL24	.486[1]	.530	.393	.403	1.105	.469	.526[4]
TOFIRSTO	70.64[2]	63.49	86.39	80.45	26.96	72.11	67.65
TOMAXO	119.42[2]	115.71	127.59	130.34	70.82	122.65	112.87
TOFIRSTG	89.21[3]	85.68	97.11	101.78	34.36	91.30	84.98
TOMAXG	131.63[3]	130.29	134.64	143.31	80.67	135.65	123.52

[1]Mean defined for 1223 leases.

[2]Mean defined for 457 oil-producing leases.

[3]Mean defined for 456 gas-producing leases.

[4]The mean value of LNWELL24 for joint leases exceeds the mean for solo leases because of the greater proportion of joint leases which are drainage leases. The regression analysis corrects for this, with the result that joint leases are shown to have a significantly lower level of developmental drilling activity than solo leases, as indicated in Model 4A, p. 92, above.

MODEL 4B.

DEPENDENT VARIABLE: LOG. OF NUMBER OF WELLS DRILLED IN THE FIRST 24 MONTHS FOLLOWING SALE DATE. 1223 LEASES.

R^2 = .4206

DEP. VAR: LNWELL24

VARIABLE	PARAMETER ESTIMATE	T-RATIO
INTERCEPT	-1.043650	-8.2670*
LNBONPA	0.196774	16.3884*
YOS	0.024759	5.9233*
LNWATDEP	0.023497	0.9169
DSTATE	-0.074196	-1.6949
PROD01	0.381483	10.5297*
B8WS	0.121045	2.8535*
B8WJ	0.032292	0.6532
B8DS	0.437005	5.4417*
B8DJ	0.034519	0.3460
NB8WJ	0.015499	0.2050
NB8DS	-0.012380	-0.1022
NB8DJ	0.132165	0.6872

*Significant at the 5% level (two-tailed test)

TABLE 21.

T-RATIOS FOR COEFFICIENTS OF INTERACTION VARIABLES IN MODEL 4B (LNWELL24) WITH VARYING BASE CASE

	B8WS	B8WJ	B8DS	B8DJ	NB8WS	NB8WJ	NB8DS	NB8DJ
B8WS		(-2.01)*	(4.01)*	(-0.88)	(-2.85)*	(-1.45)	(-1.11)	(0.06)
B8WJ	(2.01)*		(4.92)*	(0.02)	(-0.65)	(-0.22)	(-0.36)	(0.52)
B8DS	(-4.01)*	(-4.92)*		(-3.62)*	(-5.44)*	(-4.31)*	(-3.44)*	(-1.54)
B8DJ	(0.88)	(-0.02)	(3.62)*		(-0.35)	(-0.17)	(-0.33)	(0.47)
NB8WS	(2.85)*	(0.65)	(5.44)*	(0.35)		(0.21)	(-0.10)	(0.69)
NB8WJ	(1.45)	(0.22)	(4.31)*	(0.17)	(-0.21)		(-0.21)	(0.58)
NB8DS	(1.11)	(0.36)	(3.44)*	(0.33)	(0.10)	(0.21)		(0.66)
NB8DJ	(-0.06)	(-0.52)	(1.54)	(-0.47)	(-0.69)	(-0.58)	(-0.66)	

*Significant at the 5 percent level (two-tailed test).

NOTE: The row variables are the base cases. A positive t-ratio indicates that the base case drills more wells in the first 24 months following lease sale date than the corresponding column case (and conversely for a negative t-ratio).

have been used as base cases for regression runs. To read Table 21,one first chooses a base case from the eight listed in the left hand column. The numbers shown in cells along the rows are T-values, indicating that the lease categories listed along the top row of the table are either greater than the base category (if T-value is positive) or smaller than the base category (if negative). Significant differences between categories are starred. The part of the table above the diagonal is the "mirror image" of that below. Only eight of the twenty-eight possible comparisons between categories in Table show significant differences (as noted by asterisks). Six of these derive from one base case, B8DS. This category of leases drilled significantly more wells than all other categories except NB8DJ. B8WS is also shown to have drilled significantly more wells than NB8WS and B8WJ. One sees in these results the positive significance of Big-8 as compared to non-Big-8 leases in both wildcat/solo and drainage/solo categories. Drainage leases are drilled significantly faster than wildcat leases only within the Big-8/solo sub-category. For the parallel cases in which solo leases are compared to joint leases, B8DS drilled more than B8DJ and B8WS drilled more than B8WJ.

Time to First Oil Production

Models 5A and 5B report regression results for our model of time required (in months from lease sale) to achieve first oil production. These models are the same as 4A and 4B except that a dummy variable GAS01 replaces PROD01 and the variable AWELLDEP is added as an additional measure of relative costs. These regressions are run only for those leases (457) which actually produced oil, thus PROD01 is irrelevant. GAS01 is a dummy variable distinquishing predominantly gas leases (where dummy variable = 1) from predominantly oil leases, as defined on a BTU-equivalent basis. We used the GAS01 (and the later reported OIL01) dummy variables on the hypotheses that the time required for producing oil would be greater when oil is a secondary product of gas production, while the time required to produce gas would decrease when gas is a secondary product of oil production (assuming that gas cannot be flared).

The regression results show that Model 5A has only limited ability to explain variations in time to first oil production (R^2 = .3770). LNBONPA and YOS are both significant and negative indicating that leases perceived to be of higher quality produce faster and that time to first production has been significantly reduced over the lease sale years 1954-1969. LNWATDEP is significant and positive; time to first oil is shown to be greater for productive leases located in deeper water. GAS01 is positive and significant meaning that predominantly gas leases achieve first oil production slower than predominantly oil leases. This is consistent with our expectations. Such oil would probably not be produced until gas pipelines were available to transport the major lease product, and such pipelines are rarely already in place near a newly-developed lease. DSTATE and AWELLDEP are both insignificant.

The dummy variables BIG801 and DWILDDR are both significant; JOINT01 is insignificant. Averages (mean values) for these lease categories are reported in Table 20. Time to first oil averages about 27 months for drainage leases, but 80.45 months for wildcat leases. Big-8 leases produced first oil in 63.49 months on average; non-Big-8 leases were significantly slower, averaging 86.39 months.

Model 5B (similar to Model 4B) is a more detailed investigation of the factors responsible for time to first oil. Again, the model as

MODEL 5A.

DEPENDENT VARIABLE: MONTHS TO FIRST OIL PRODUCTION. 457 OIL PRODUCING LEASES.

$R^2 = .3770$

DEP. VAR: TOFIRSTO

VARIABLE	PARAMETER ESTIMATE	T-RATIO
INTERCEPT	87.672575	4.7905*
LNBONPA	-8.074630	-5.7334*
YOS	-1.786905	-3.4751*
LNWATDEP	9.291533	3.0129*
DSTATE	1.184815	0.1464
GAS01	32.411601	7.6262*
AWELLDEP	-0.000754662	-1.2749
BIG801	-9.348464	-2.2613*
JOINT01	0.579930	0.1435
DWILDDR	-23.523266	-3.6383*

*significant at the 5% level (two-tailed test)

MODEL 5B.

DEPENDENT VARIABLE: MONTHS TO FIRST OIL PRODUCTION.
457 OIL PRODUCING LEASES.

R^2 = .3796

DEP. VAR: TOFIRSTO

VARIABLE	PARAMETER ESTIMATE	T-RATIO
INTERCEPT	88.814285	4.8023*
LNBONPA	-8.017273	-5.6586*
YOS	-1.768125	-3.4246*
LNWATDEP	9.284540	2.9780*
DSTATE	1.388587	0.1705
GAS01	32.309821	7.5076*
AWELLDEP	-0.000762531	-1.2793
B8WS	-11.017251	-2.0952*
B8WJ	-9.294378	-1.5733
B8DS	-35.889787	-4.0061*
B8DJ	-33.414399	-3.4790*
NB8WJ	-6.652119	-0.7961
NB8DS	-28.419335	-2.1487*
NB8DJ	-8.316767	-0.4398

*significant at 5% level (two-tailed test)

TABLE 22.

T-RATIOS FOR COEFFICIENTS OF INTERACTION VARIABLES IN MODEL 5B (TOFIRSTO) WITH VARYING BASE CASE

	B8WS	B8WJ	B8DS	B8DJ	NB8WS	NB8WJ	NB8DS	NB8DJ
B8WS		(0.32)	(-2.98)*	(-2.43)*	(2.10)*	(0.55)	(-1.33)	(0.14)
B8WJ	(-0.32)		(-3.09)*	(-2.59)*	(1.57)	(0.32)	(-1.47)	(0.05)
B8DS	(2.98)*	(3.09)		(0.25)	(4.01)*	(2.82)*	(0.56)	(1.47)
B8DJ	(2.43)*	(2.59)*	(0.25)		(3.48)*	(2.44)*	(0.37)	(1.31)
NB8WS	(-2.10)*	(-1.57)	(-4.01)*	(-3.48)*		(-0.80)	(-2.15)*	(-0.44)
NB8WJ	(-0.55)	(-0.32)	(-2.82)*	(-2.44)*	(0.80)		(-1.52)	(-0.09)
NB8DS	(1.33)	(1.47)	(-0.56)	(-0.37)	(2.15)*	(1.52)		(0.95)
NB8DJ	(-0.14)	(-0.05)	(-1.47)	(-1.31)	(0.44)	(0.09)	(-0.95)	

*Significant at the 5 percent level (two-tailed test).

NOTE: The row variables are the base cases. A positive t-ratio indicates that the base case gets faster to first oil production than the corresponding column case (and conversily for a negative t-ratio).

reported here uses NB8WS as the base case. Results for all interaction variables and all base cases are given in Table 22. Important findings are that B8DS and B8DJ leases produce first oil significantly faster than the four wildcat lease categories. B8WS is significantly faster than NB8WS. There is strong evidence in these findings of the significance of the drainage category and the Big-8 category as factors influencing speed to first oil.

Time to Maximum Oil Production

Models 6A and 6B are identical (respectively) to Models 5A and 5B, except that the dependent variable is now time (in months from date of lease sale) to maximum oil production. The explanatory power of Model 6A is somewhat stronger than for 5A (R^2 = .4059). The same variables are significant and insignificant in this model as were reported for Model 5A, with two important exceptions: (1) The policy-oriented variable BIG801, which was significant in 5A, is no longer significant; and (2) Water depth becomes insignificant in Model 6A. Thus, only one of our three policy-related lease categories, represented by DWILDDR, is significant in explaining time to maximum oil productions.

Mean values of the dependent variable for various lease categories are reported in Table 20. While drainage leases require only 70.82 months on average to achieve maximum oil production, wildcat leases require 130.34 months.

Results for our interaction variables are shown in Model 6B (where NB8WS is the base case) and in Table 23,where all eight base cases may be examined. We observe that B8DJ is significantly faster to maximum oil production than any of the four wildcat categories, that B8DS is significantly faster than NB8WJ, and that NB8DS is faster than NB8WJ. These

Model 6A.

Dependent Variable: Months to Maximum Oil Production.
457 Oil Producing Leases.

R^2 = .4059

Dep. Var.: TOMAXO

Variable	Parameter Estimate	T-Ratio
INTERCEPT	166.573825	8.3464*
LNBONPA	-3.276566	-2.1335*
YOS	-6.360732	-11.3436*
LNWATDEP	6.338972	1.8849
DSTATE	-10.280953	-1.1650
GAS01	14.853972	3.2050*
AWELLDEP	-0.00102128	-1.5822
BIG801	-2.540298	-0.5635
JOINT01	-0.555042	-0.1259
DWILDDR	-21.193586	-3.0059*

*Significant at 5% level (two-tailed test).

Model 6B.

Dependent Variable: Months to Maximum Oil Production.
457 Oil Producing Leases.

R^2 = .4095

Dep. Var.: TOMAXO

Variable	Parameter Estimate	T-Ratio
INTERCEPT	167.753351	8.3259*
LNBONPA	-3.386805	-2.1942*
YOS	-6.406874	-11.3906*
LNWATDEP	5.988909	1.7633
DSTATE	-10.894283	-1.2276
GAS01	15.837985	3.3780*
AWELLDEP	-0.00111342	-1.7146
B8WS	-0.553979	-0.0967
B8WJ	-1.916689	-0.2978
B8DS	-16.021304	-1.6415
B8DJ	-28.713693	-2.7441*
NB8WJ	6.743478	0.7408
NB8DS	-27.042821	-1.8768
NB8DJ	-7.692634	-0.3734

*Significant at the 5% level (two-tailed test).

TABLE 23.

T-RATIOS FOR COEFFICIENTS OF INTERACTION VARIABLES
IN MODEL 6B (TOMAXO) WITH VARYING BASE CASE

	B8WS	B8WJ	B8DS	B8DJ	NB8WS	NB8WJ	NB8DS	NB8DJ
B8WS		(-0.23)	(-1.70)	(-2.81)*	(0.10)	(0.84)	(-1.86)	(-0.35)
B8WJ	(0.23)		(-1.51)	(-2.64)*	(0.30)	(0.95)	(-1.77)	(-0.28)
B8DS	(1.70)	(1.51)		(-1.19)	(1.64)	(2.02)*	(-0.76)	(0.41)
B8DJ	(2.81)*	(2.64)*	(1.19)		(2.74)*	(2.97)*	(0.11)	(1.01)
NB8WS	(-0.10)	(-0.30)	(-1.64)	(-2.74)*		(0.74)	(-1.88)	(-0.37)
NB8WJ	(-0.84)	(-0.95)	(-2.02)*	(-2.97)*	(-0.74)		(-2.16)*	(-0.68)
NB8DS	(1.86)	(1.77)	(0.76)	(-0.11)	(1.88)	(2.16)*		(0.84)
NB8DJ	(0.35)	(0.28)	(-0.41)	(-1.01)	(0.37)	(0.68)	(-0.84)	

*Significant at the 5 percent level (two-tailed test).

NOTE: The row variables are the base cases. A positive t-ratio indicates that the base case gets faster to maximum oil production than the corresponding column case (and conversely for a negative t-ratio).

results mainly point to the dominance of drainage categories over wildcat categories. The last two comparisons noted (B8DS-NB8WJ and NB8DS-NB8WJ) are not parallel cases, so conclusions cannot easily be drawn from them.

Time to First Gas Production

Models 7A and 7B present regression results for expeditious production measured by time (in months) from lease sale to first gas production. These regressions were run only for the 456 gas-producing leases. Model 7A, which uses the three policy-related dummy variables, shows increased explanatory power over the previously discussed models (R^2 = .4735). The independent variables in this model behave very much the same as they did in the models of oil production: LNBONPA and YOS are significant and negative, indicating a reduced time to first gas is associated with perceived lease quality and with later lease sale dates. LNWATDEP is significant and positive, indicating that tracts in deeper water are slower in developing first production, probably because of pipeline construction delays. The new dummy variable OIL01 (which replaces GAS01 in the equations where gas production is the dependent variable) is significant and negative. This supports our hypothesis that gas will be produced in fewer months if the lease is prodominantly an oil lease, because the alternative of flaring the gas is either prohibited or is costly.

DWILDDR is significant and negative — drainage leases produce first gas more quickly than wildcat leases. BIG801 and JOINT01 are both insignificant. Mean values for the dependent variable, as shown in Table 20, indicate that an average of 34.36 months is required for production of first gas on drainage leases, while wildcat leases require almost three times as many months on average: 101.78.

Model 7A.

Dependent Variable: Months to First Gas Production.
456 Gas Producing Leases.

$R^2 = .4735$

Dep. Var.: TOFIRSTG

Variable	Parameter Estimate	T-Ratio
INTERCEPT	133.966667	7.9883*
LNBONPA	-5.517677	-3.9619*
YOS	-6.378123	-12.5055*
LNWATDEP	11.230989	3.6850*
DSTATE	13.679456	1.7189
OIL01	-10.749215	-2.5279*
AWELLDEP	-0.000626655	-1.0882
BIG801	-2.560737	-0.6272
JOINT01	5.089022	1.2754
DWILDDR	-21.153471	-3.3261*

*Significant at the 5% level (two-tailed test).

Model 7B.

Dependent Variable: Months to First Gas Production.
456 Gas Producing Leases.

R^2 = .4758

Dep. Var.: TOFIRSTG

Variable	Parameter Estimate	T-Ratio
INTERCEPT	134.216880	7.8866*
LNBONPA	-5.511692	-3.9363*
YOS	-6.360640	-12.4172*
LNWATDEP	11.209597	3.6398*
DSTATE	13.459422	1.6804
OIL01	-10.835642	-2.5120*
AWELLDEP	-0.000644158	-1.1099
B8WS	-1.685004	-0.3224
B8WJ	1.711822	0.2928
B8DS	-27.783137	-3.1545*
B8DJ	-16.507015	-1.7418
NB8WJ	1.839935	0.2231
NB8DS	-21.634723	-1.6602
NB8DJ	1.635481	0.0878

*Significant at the 5% level (two-tailed test).

TABLE 24.

T-RATIOS FOR COEFFICIENTS OF INTERACTION VARIABLES IN MODEL 7B (TOFIRSTG) WITH VARYING BASE CASE

	B8WS	B8WJ	B8DS	B8DJ	NB8WS	NB8WJ	NB8DS	NB8DJ
B8WS		(0.64)	(-3.19)*	(-1.64)	(0.32)	(0.45)	(-1.55)	(0.18)
B8WJ	(-0.64)		(-3.50)*	(-1.99)	(-0.29)	(0.02)	(-1.82)	(-0.004)
B8DS	(3.19)*	(3.50)*		(1.18)	(3.15)*	(2.91)*	(0.47)	(1.60)
B8DJ	(1.63)	(1.99)	(-1.18)		(1.74)	(1.70)	(-0.38)	(0.97)
NB8WS	(-0.32)	(0.29)	(-3.15)*	(-1.74)		(0.22)	(-1.66)	(-0.09)
NB8WJ	(-0.45)	(-0.02)	(-2.91)*	(-1.70)	(-0.22)		(-1.66)	(-0.01)
NB8DS	(1.55)	(1.82)	(-0.47)	(0.38)	(1.66)	(1.66)		(1.12)
NB8DJ	(-0.18)	(0.004)	(-1.60)	(-0.96)	(0.09)	(0.01)	(-1.12)	

*Significant at the 5 percent level (two-tailed test).

NOTE: The row variables are the base cases. A positive t-ratio indicates that the base case gets faster to first gas production than the corresponding column case (and conversely for a negative t-ratio).

Results for the Model 7B where the eight interaction variables replace the three dummy variables show that significant differences in time to first gas are confined to the two Big-8 drainage sub-categories. B8DS is significantly faster to first gas than the four wildcat sub-categories (B8WS, B8WJ, NB8WS, and B8WJ). B8DJ is significantly faster than B8WJ. There is no evidence here of significance for Big-8 over non-Big-8 or for joint leases over solo leases. Note again that Model 7B is reported using NB8WS as the base case. Detailed results for all eight base cases are given in Table 24.

Time to Maximum Gas Production

Our final models of expeditious production use time to maximum gas production as dependent variables. We would expect these models (8A and 8B) to show results very similar to 7A and 7B and our expectations are generally borne out. The explanatory power of Model 8A is the highest of any of our models of expeditious development: R^2 = .5096. LNBONPA and YOS are still significant and negative, but LNWATDEP and OIL01 are no longer significant. It appears that predominantly oil leases which also produce gas are faster to first gas production but are not significantly faster to maximum gas production. The variable AWELLDEP, which was insignificant in Models 5, 6, and 7, is here shown to be significant but negative. This contradicts our hypothesis that tracts with deeper average well depth would be slower to develop. This anomalous result must reflect some peculiarity in the distribution of gas-producing leases such that facilities for full development of these leases were located nearer to deep-well leases than to shallow-well leases.

As in Model 7A, DWILDDR is significant and negative while BIG801 and JOINT01 are not significant. The average time required to achieve maximum gas production (as shown in Table 20) is 80.67 months for drainage leases, 143.31 months for wildcat leases.

Results for the regression runs using the eight interaction variables are reported in Model 8B (where NB8WS is the base case) and Table 25 (where all eight base cases have been run). Again only certain drainage sub-categories are shown to have displayed significantly faster time to maximum gas production. B8DJ reached maximum gas production significantly faster than B8WS, B8WJ and NB8WJ; B8DS was faster than B8WS and NBWJ; and NB8DS was significantly faster than all four wildcat sub-categories. This is an even stronger showing than given in Model 7B of the significance of the drainage distinction. Three of the four drainage sub-categories display significantly greater speed to maximum gas production than their parallel cases among wildcat leases. But again there is no suggestion that the Big-8/non-Big-8 or joint/solo distinctions make any significant difference in determining time to maximum gas production.

Summary of Regression Results on Expeditious Development

From the point-of-view of OCS lease management policy, our findings concerning expeditious development support our original hypothesis that no extraordinary penalties or oversight pressures on lessees are needed to insure that lessees will explore and produce from leased tracts in a diligent manner. Our model of exploratory drilling shows that Big-8 leases, solo leases, and drainage leases are drilled significantly more intensively in the 24 months following lease sale than are non-Big-8, joint, or wildcat leases (respectively). Since most suspicion concerning motivation for retarding lease development has been directed toward Big-8 lessees, this finding tends to undercut the monopoly argument. The finding that solo bidders drill more intensively in the early life of a lease than joint bidders would seem to indicate that coordination and

Model 8A.

Dependent Variable: Months to Maximum Gas Production.
456 Gas Producing Leases.

R^2 = .5096

Dep. Var.: TOMAXG

Variable	Parameter Estimate	T-Ratio
INTERCEPT	198.067308	11.6059*
LNBONPA	-2.857810	-2.0165*
YQS	-7.791347	-15.0117*
LNWATDEP	5.753781	1.8552
DSTATE	-10.162447	-1.2555
OIL01	1.157775	0.2676
AWELLDEP	-0.00120728	-2.0601*
BIG801	2.067597	0.4977
JOINT01	-0.096555	-0.0238
DWILDDR	-19.732479	-3.0489*

*Significant at the 5% level (two-tailed test).

Model 8B.

Dependent Variable: Months to Maximum Gas Production.
456 Gas Producing Leases.

R^2 = .5136

Dep. Var.: TOMAXG

Variable	Parameter Estimate	T-Ratio
INTERCEPT	200.752058	11.6150*
LNBONPA	-2.947889	-2.0729*
YQS	-7.835935	-15.0622*
LNWATDEP	5.252610	1.6793
DSTATE	-11.303011	-1.3895
OIL01	-0.100643	-0.0230
AWELLDEP	-0.00132304	-2.2446*
B8WS	5.557986	1.0471
B8WJ	1.647187	0.2774
B8DS	-12.615636	-1.4104
B8DJ	-18.337597	-1.9052
NB8WJ	8.388012	1.0015
NB8DS	-27.710874	-2.0938*
NB8DJ	1.210433	0.0640

*Significant at the 5% level (two-tailed test).

TABLE 25.

T-RATIOS FOR COEFFICIENTS OF INTERACTION VARIABLES IN MODEL 8B (TOMAXG) WITH VARYING BASE CASE

	B8WS	B8WJ	B8DS	B8DJ	NB8WS	NB8WJ	NB8DS	NB8DJ
B8WS		(-0.72)	(-2.19)*	(-2.60)*	(-1.05)	(0.36)	(-2.55)*	(-0.23)
B8WJ	(0.72)		(-1.67)	(-2.15)*	(-0.28)	(0.81)	(-2.25)*	(-0.02)
B8DS	(2.19)*	(1.67)		(-0.59)	(1.41)	(2.03)*	(-1.14)	(0.74)
B8DJ	(2.60)*	(2.15)*	(0.59)		(1.91)	(2.44)*	(-0.69)	(1.02)
NB8WS	(1.05)	(0.28)	(-1.41)	(-1.91)		(1.00)	(-2.09)*	(-0.06)
NB8WJ	(-0.36)	(-0.81)	(-2.03)*	(-2.44)*	(-1.00)		(-2.52)*	(-0.37)
NB8DS	(2.55)*	(2.25)*	(1.14)	(0.69)	(2.09)*	(2.52)*		(1.37)
NB8DJ	(0.23)	(0.02)	(-0.74)	(-1.02)	(-0.06)	(0.37)	(-1.37)	

*Significant at the 5 percent level (two-tailed test).

NOTE: The row variables are the base cases. A positive t-ratio indicates that the base case gets faster to maximum gas production than the corresponding column case (and conversely for a negative t-ratio).

decision-making among joint venture lessees is more difficult, at least for the leases in our study.

Our models of expeditious production of oil reinforce the significance of the drainage/wildcat distinction (as expected). Big-8 leases are shown to be significantly faster in achieving first oil production than non-Big-8 leases, but there are no significant differences by firm size in time required to reach maximum oil production. The joint/solo distinction is not significant for either oil production model, meaning that joint ventures and solo ventures develop first and maximum oil production at speeds which are not significantly different. These findings support those relating to expeditious drilling in that only drainage leases and Big-8 leases are developed at faster rates than other leases. The monopoly argument is not supported.

Finally, our models of expeditious gas production show that the only significant distinction among leases in regard to speed to first gas and speed to maximum gas is the drainage/wildcat designation. Neither size of firm (Big-8 vs. non-Big-8) nor type of bidding arrangement (joint vs. solo) has any significant effect on time to first gas or time to maximum gas. Those differences in speed of development which are observed among leases are explained by basic geological or economic factors or constraints, not by purposeful action on the part of large firms (whether operating as solo bidders or in joint ventures with other firms) attempting to delay drilling or production. Indeed, our findings suggest that the only significant effects produced by large firms in respect to expeditious development are to increase the speed of lease drilling (LNWELL24) and to reduce the time required to produce first oil (TOFIRSTO). We find nothing to support the hypothesis that large firms have acted to delay either drilling or production.

There is some support for the argument that joint bidders are slower in getting drilling programs started than are solo bidders. This effect is not present, however, in measures of speed to actual production of oil and gas, where there is no indication of any significant difference between joint bidders and solo bidders. Thus, the policy relevance of the joint/solo bidder distinction, at least for the issue of expeditious development, is very small.

APPENDIX 1.

Data and Algorithms Used to Compute Lease-Specific Cash-Flows

I. Data Sources.

The principal source of lease-specific data was the LPR-19D data base. This base contains, among other items, the drilling record through 1976 for the 1223 leases. For the purpose of estimating costs, detailed studies were made of investment and expenditure patterns for offshore petroleum exploration and development relevant for the area and time period. These studies drew mostly on industry sources of information and published data, most importantly the industry surveys referenced below. It was not possible to determine all costs on a lease-specific basis, but the majority of costs, as reflected in the bidding, drilling, rent and royalty payment records of LPR-19D, are lease-specific. Still the cost estimates must be thought of as averages for all leases in the relevant category, because exploration costs, platform costs and other costs have been averaged for each year.

Estimates have been made of pre-lease exploration costs, post-lease exploration, drilling, development and operating costs. Projections have been made of future liquids and gas production with estimated operating costs by year. At lease shut down, an estimated abandonment cost was subtracted from the net cash flow of the lease.

The remainder of this appendix contains in more detail the justification, data sources and algorithms which these estimates have been based on.

II. Output and Revenue.

1) Annual revenue for the historical period.
Lease gross revenue for years from lease sale through 1978 equals actual royalty payments times 6.

2) Future production and revenue.
A constant exponential decline rate was used to predict future levels of output for liquids (= oil + condensate), gas and other hydrocarbons (classified as "other"). Under this method

$$Q_i = Q_{i-1} \cdot e^{-d}$$

where Q is the quantity in question subscripted by reference to a particular year. i may range from 1979 to 2010, e is the base of the natural logarithmic system, and d is the decline rate.

The decline rate applied in our IRR analysis was .15. This rate was selected by observing decline rates for a sample of leases issued early in the period under study such that their peak production occurred within the period where historical information on production levels is available. This rate was found to be the most appropriate in describing production declines for the leases in the sample. As mentioned in the main section of this report, tests of sensitivity of the aggregate IRR to choice of decline rate were performed. The IRR was found to be relatively insensitive to different choices within the range .10 - .20.

Future gross revenue was computed as the product of predicted future production times predicted future prices net of "windfall profits taxes" on oil, as described in detail in Appendix 4.

III. Cost Estimates.

1. Exploration costs.
See Appendix 2.

2. Costs of drilling and equipping wells.

i) Data source and definition of cost elements

Our source of data was the Joint Association Survey of the U.S. oil and gas producing industry (JAS)[1] which has been issued annually since 1955 with the exception of the years 1957-58. The JAS surveys contain the most detailed and systematically collected data available on drilling and well equipment costs. The costs of wells in the JAS surveys have been classified by year, geographical location, type (oil, gas or dry) and depth category. Following the JAS classifications, the same four labels were attached to each well drilled on any of the 1223 leases covered by our study. These labels then define the cost estimate of a particular well.

Two problems with the JAS data made it necessary for us to make adjustments. As mentioned above, surveys are not available for the years 1957-1958. Drilling costs for these years were estimated by interpolation between the 1956 and the 1959 entries. A second problem is that the sample sizes of certain well categories for certain years are very small and, in some cases, some categories have not been sampled at all. Occasionally a small sample size has led to a cost estimate for a well category which was higher than that for a deeper well in the same category and year. In such cases, and in cases where no sample existed, we have interpolated between depth categories to overcome the shortcomings of the JAS data. Thus unrealistic estimates were ignored and estimates missing from the JAS data were generated.

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[1] Joint Association Survey of the U.S. Oil and Gas Producing Industry. American Petroleum Institute, Washington, D.C. The survey has sections on drilling costs and on expenditures for exploration, development and production.

The cost elements which respondents to the JAS survey are asked to include as well drilling costs are:[1]

"...expenditures for drilling dry holes and productive wells and equipping new productive wells through the Christmas tree installation. More specifically, these cost elements are the costs of labor, materials, supplies, water, fuels, power, and direct overhead (i.e. field, district, and regional), for such operations as site preparation, road building, erecting and dismantling derricks and drilling rigs, drilling holes, running and cementing casing, hauling materials, etc. Include the total cost of water, if purchased, or cost of water well, if drilled and chargeable to oil or gas well drilling operations. Well costs also include machinery and tool charges and rentals, and depreciation charges, where appropriate, for rigs and other equipment and facilities which will be used in drilling more than one well. Deduct the condition value of materials salvaged after use where appropriate.

"For offshore wells, include costs of fixed platforms and islands. Where facilities serve more than one well, the costs should be allocated to each well on the basis of the operator's best current estimate of the ultimate number of wells that will use the facility. Also, include cost expirations (depreciation or amortization) for company-owned mobile platforms, barges, and tenders."

The sum of these cost elements corresponds to the cost category we have labelled "costs of drilling and equipping wells."

The set of cost estimates in this category is not reproduced here due to its length. It is available from the authors.

ii) Algorithm for Drilling and Equipping Costs.

The costs of a well enter the cash flow of the lease in the spud year (the year drilling begins).

The JAS data allowed us to make a distinction between wells drilled offshore Louisiana and wells drilled in other parts of the Gulf of Mexico.

The costs of drilling and equipping wells differ between oil and gas wells, the former generally being more expensive than the latter. And, naturally, a dry well is generally less expensive than either of these. If the oil and condensate BTU value of the lease in the historical period exceeded the gas BTU value, then the lease was defined as an oil lease. If not, the lease was defined as a gas lease. A lease with no production was designated a dry lease.

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[1]Source: 1976 Joint Association Survey, Section 1 (Drilling Costs), p. 62.

For oil leases:

The cost of a well, of given depth and spud date, was calculated as follows; CW_i = cost of i^{th} well on tract

For the first 11 wells on a tract (i = 1 to 11),

$$CW_i = (.65)\ (\text{Cost of oil well}) + (.35)\ (\text{Cost of dry well})$$

For the 12th through 16th well (i = 12 through 16)

$$CW_i = (.775)\ (\text{Cost of oil well}) + (.225)\ (\text{Cost of dry well})$$

For the 17th and later wells (i = 17 and larger)

$$CW_i = (.90)\ (\text{Cost of oil well}) + (.10)\ (\text{Cost of dry well})$$

For gas leases:

The cost of wells on gas leases was calculated as shown above, except that the cost of gas wells replaced the cost of oil wells in the formulas for CW_i.

For dry leases:

All wells drilled on a dry tract were dry wells.

Our algorithm assumes that as more wells are drilled on a lease, the probability of drilling dry wells declines. This algorithm is consistent with industry experience and with USGS data on the number of producing wells on each lease in 1978.

Well depth categories, corresponding to those in the JAS surveys, are shown in Table 26.

TABLE 26.

Depth Categories for Wells

Category	Upper Bound (feet)
1	1250
2	2500
3	3750
4	5000
5	7500
6	10000
7	12500
8	15000
9	17500
10	20000
11	Unlimited

3. Costs of equipment beyond the Christmas tree.

The per well costs of equipment beyond the christmas tree were also estimated using data from the Joint Association Surveys mentioned in the preceding section. The cost estimates in this category are those necessary to convert a drilled well to a producing well. More specifically, they are the costs of artificial lift equipment and downhole lift equipment, flow lines, flow tanks, separators and related field facilities.

The costs in this category for any given lease in any given year were set equal to the number of initially productive wells drilled in that year (defined in the next section) times the equipment costs per well, from the table below.

TABLE 27.

Cost Per Well for Equipment Beyond the Christmas Tree for Initially Productive Wells

Year	Cost	Year	Cost
1955	$60,547	1966	$78,962
1956	60,764	1967	77,163
1957	62,443	1968	81,889
1958	64,121	1969	95,321
1959	65,800	1970	96,260
1960	65,423	1971	103,961
1961	64,610	1972	114,724
1962	61,775	1973	115,830
1963	62,958	1974	140,303
1964	62,622	1975	180,433
1965	70,286	1976	211,670

4. Operating costs.

Operating costs per well were estimated from JAS data and from a survey of oil companies which we conducted. Included were lifting costs and all other costs directly applicable to the production of petroleum as distinguished from drilling and initial installment of equipment necessary for production. More specifically, the costs in this category are those of labor, field supervision, repair and maintenance, fuel, power, water, small tools and supplies, etc. Operating costs are calculated on the basis of the number of operating wells, with no distinction between oil and gas wells. This approach most closely reflects industry experience. Operating costs in each year were calculated as the number of currently productive wells times an operating cost per well. The number of currently productive wells was calculated by a two step procedure. Note: dry leases have no productive wells.

1) Calculate the number of initially productive wells by year (fractional wells are allowed) in the following manner:

    65% of the first eleven wells on each lease are "initially productive"
    77.5% of the 12th through 16th wells on each lease are "initially productive"
    90% of the wells beyond the 16th wells are "initially productive"

2) Calculate the number of "currently productive" wells in the following manner:

$$CPW_t = IPW_t + (0.96)\ (CPW_{t-1})$$

where, CPW_t is the number of currently productive wells in year t, and IPW_t is the number of initially productive wells in year t.

EXAMPLE

Year	Number of Wells Drilled	IPW_t	CPW_t
1	10	6.5	6.5
2	4	2.975*	9.215
3	8	6.95**	15.7964
4	0	0.	15.1645

*2.975 = (.65 x 1) + (.775 x 3)
**6.95 = (.775 x 2) + (.90 x 6)

Table 28 shows operating costs by year. For years after 1976, operating costs were estimated using the Chase Econometrics, Inc., estimate of the GNP deflator applied to the 1976 number (see Appendix 4).

TABLE 28.

Operating Cost Per Currently Productive Well

Year	Cost	Year	Cost
1954	$35,000	1965	$38,000
1955	35,000	1966	38,000
1956	35,000	1967	40,000
1957	35,000	1968	40,000
1958	35,000	1969	41,000
1959	35,000	1970	42,000
1960	35,000	1971	42,000
1961	35,000	1972	54,000
1962	35,000	1973	60,000
1963	35,000	1974	70,000
1964	38,000	1975	90,000
		1976	90,000

5. Marginal overhead costs.

Overhead expenses relating to bidding, planning, and accounting rise as the activity related to offshore leases acquired by a company rises. We have estimated these marginal overhead costs for each year to be 5% of that year's total costs of drilling and equipping wells, costs of equipment beyond the christmas tree, and operating costs.

6. Costs of Bonus, Rent and Royalty

These costs were taken from the LPR-19D data base. They are derived from USGS historical records. They reflect industry experience exactly, except for minor accounting revisions which sometimes move revenues (royalties) from one year to the next.

7. Costs of Abandonment

Abandonment represents a relatively new component of costs for oil companies operating in OCS areas. Prior to 1970, only a few very old, shallow-water platforms had been abandoned.[1] In these cases, the salvage value of equipment and materials was approximately equal to the removal and dismantling costs, producing no net cost.

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[1]For the 839 leases issued in the Gulf of Mexico between 1954 and 1962, the record indicates that only 15 tracts had been relinquished with associated abandonment of platforms through 1976.

The combination of stricter environmental regulations affecting abandonment, platform installations in deeper water (with greater numbers and strength of pilings), and reductions in the relative scrap values of equipment and materials salvaged from abandoned tracts, has led to a rapid increase in net abandonment costs in recent years. Oil companies currently expect that platform abandonment will impose a future cost approximately equal to current installation cost, and are taking these future costs into account in estimating bonus bids for OCS tracts.

We have obtained information on abandonment costs from three major oil companies. In two cases, these data are confidential; in the third, the data have been supplied as part of the public record before the Federal Energy Regulatory Commission.

In one case, the offshore operator reports that a six well platform in the Gulf of Mexico installed in 1960 in 145 feet of water was abandoned in 1977 at a net of salvage cost of over $600,000 for the platform plus an additional net cost per well of about $100,000. A second case closely parallels this case in respect to total abandonment costs in the post-1973 period.

In a third case,[1] the costs of abandonment and removal for a typical ten well platform in 1978 have been summarized as follows:

1. Production Equipment Removal -- $500,000 per platform.

2. Salvaging Production Equipment -- Recovery of salvage value depends upon the age of the salvaged equipment. Equipment older than eight years (typical case) will have a salvage value of approximately 2½% of original cost.

3. Well abandonment -- All wells and other structures must be removed to 15 feet below the mud line according to present U.S.G.S. regulations. All porous zones must be permanently shut off from other zones. Total costs (1978) were estimated to average $130,000 per well for single completions and $160,000 per well for dual completions. Abandonment of wells drilled with a jack-up will be approximately 25% greater.

4. Tubular goods and casing head assembly salvage -- value in used market is at maximum 25% of new cost.

5. Platform Removal and Dismantling -- Diving requirements, water depth, and number of pilings determine the cost. Dismantling and salvage require the cutting up of compon[ents] into small pieces which have a 1978 value (Houston) of $40-$50/ton.

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[1] FERC Docket Nos. CI77-702, CI78-96, CI78-498 through 503 and CI78-767, August 1978.

Net-of-salvage cost estimates for abandonment are shown in Table 29 below. These estimates incorporate the known costs of 1977-78 abandonments, the assumption that net abandonment costs in the period prior to 1970 were close to zero, and estimates of future net abandonment costs, based upon 1977 costs plus an increase equal to the forecasted increase in the GNP deflator.[1] Our forecast of future abandonment costs is below that made by a major producer in the previously-cited presentations before the FERC. This producer apparently has based its forecast upon recent very rapid increases in offshore engineering costs, which we do not believe will be sustained throughout the 1979-2010 period.

TABLE 29.

Estimated Costs of Abandonment, Gulf of Mexico OCS

Year	Net Fixed Cost Per OCS Tract ($M)	Additional Variable Cost Per Well ($M)
1967	0	0
1968	50	10
1969	100	20
1970	150	30
1971	200	40
1972	250	50
1973	300	60
1974	350	70
1975	400	80
1976	450	90
1977	500	100

The decision to abandon a lease or not was simulated by our computer program as follows: For a lease to be shut down in the period 1954-77, it must have been productive and it must have had no reported production in 1978. Such a lease is shut down in the last year of reported production. In the period 1978-2010 a lease is never shut down in a year with a positive net cash-flow. A test is performed if the net cash-flow turns negative in a particular year, t, in this period. If the absolute value of the (negative) net-cash flow in year t is smaller than the sum of one or more positive net cash-flow entries in the years beyond t, then the lease is carried on further into the

[1] The forecast for the GNP deflator is that of Chase Econometrics, Inc., 1978-2010. See Appendix 4.

future. Otherwise, the lease is abandoned and abandonment costs are incurred. In other words, even if the lease has a negative cash flow in year t, it may still be that in years beyond t there are positive cash-flow entries which more than make up for the negative entry in t. Our shutdown algorithm is designed to take this into account. Note that the abandonment costs are not allowed to influence the abandonment decision. They are merely subtracted from the lease net-cash flow after the decision to abandon has been made.

APPENDIX 2.

Exploration Costs

Exploration costs include all geophysical and geological expenses: seismic, gravity, and magnetic surveys, plus costs of geological interpretation and processing. As is true for well drilling, seismic and other geophysical survey work is usually carried out by independent contractors, not by the major oil companies. About 80% of the total acquisition cost of geophysical data is expended in the year following the sale date.

Computer processing and interpretation have risen from about 25% of data acquisition costs (1950-53) to over 100% of acquisition costs (since 1975), reflecting the improvements in computer technology and sophistication of mathematical and other modeling of geological information.

Previous studies have estimated exploration costs on a constant "dollars per line mile" or cents per barrel basis,[1] both of which ignore the trend toward greater emphasis on geophysical effort and the rapid rise since 1966 of processing-interpretation costs as a proportion of total "G and G" costs.

Our exploration cost estimates (Table 30)are based primarily upon data collected and published annually by the Society of Exploration Geophysicists (SEG). These surveys report total crew months, line miles, acquisition costs, processing costs, and rates of change from previous years for offshore seismic and other geophysical efforts, in later years targeted to specific offshore locations (Gulf of Mexico, Southern California, Cook Inlet or Atlantic OCS). Because the quality and specificity of these data vary over the years, we have obtained additional information from seven of the major offshore oil producers. These companies have studied their exploration cost outlays for various time periods (one company for 1954-62, another for 1957-62, etc. We have used these different company analyses to arrive at exploration cost estimates which are consistent with the data provided in the SEG reports, but expressed in terms of cost per OCS tract acquired.

The exploration cost estimates reported in Table 30 apply to all lease sales being studied for the years 1954-69 irrespective of sale type and specific location. Our general approach is supported by the SEG reports and by producers who provided data to us. One of these companies expressed the conclusion most succinctly: "We do not believe that exploration

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[1]See Mead, <u>op. cit.</u>, p. 522; and <u>Outer Continental Shelf Policy Issues</u>, Hearings before the Committee on Interior and Insular Affairs, U.S. Senate, Part I, March and April, 1972, p. 138. The latter source quotes a Department of Interior estimate of 15¢ per barrel as the cost of offshore exploration in the Gulf of Mexico.

costs vary to any significant degree due to geographic area, water depth, distance from shore, or whether the sale is wildcat or drainage."

Our exploration cost estimates are above those employed in the previously cited study by Mead of the 1954-55 Louisiana OCS lease sales. They are consistent with the methodology proposed in the Project Independence Task Force Report of 1974, which assumed total geology and geophysics costs for the future OCS leases would be 8.4% of cumulative production well expenditures.[1] By way of comparison, using the FEA method the exploration cost per tract acquired in the 1954-55 OCS lease sales would be about $200,000; our analysis estimates the cost of exploration for those leases to be $170,000. The difference is not large in any case. It reflects the higher ratio of exploration costs to drilling costs experienced in the period from which the FEA forecast was developed (post-1971).

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[1]Federal Energy Administration, Project Independence Blueprint, Final Task Force Report, Oil: Possible Levels of Future Production, November 1974.

Table 30.

Exploration Costs--Gulf of Mexico OCS Areas
1950-1969

Year	Cost per Crew Month (Marine Seismic)	Cost of Interpretation and Processing (as % of Data Acquisition Cost)	Total Cost per Tract Acquired (*Lease Sale Years)
1950	$120,000	25%	$150,000
1951	125,000	25	150,000
1952	130,000	25	160,000
1953	135,000	25	160,000
1954	140,000	30	170,000*
1955	145,000	30	170,000*
1956	150,000	30	175,000
1957	150,000	30	175,000
1958	150,000	35	175,000
1959	155,000	35	175,000*
1960	155,000	35	175,000*
1961	160,000	35	175,000
1962	165,000	40	180,000*
1963	170,000	40	180,000*
1964	180,000	40	180,000*
1965	200,000	30	160,000*
1966	180,000	30	150,000*
1967	120,000	50	140,000*
1968	130,000	60	160,000*
1969	155,000	60	160,000*

Sources: Society of Exploration Geophysicists Annual Reports, "Geophysical Activity in 1950-1969," Geophysics, Vols 17-35, 1951-1970; reports from seven major offshore oil producers concerning exploration costs per tract acquired or per acre acquired, 1954-1969.

APPENDIX 3.

Alternative Methods of Aggregating Lease Net Cash Flows

Our estimated aggregate IRR is affected by our choice of base year(s). We have treated all 1223 leases as a continuous stream of net cash flows beginning in year zero, defined as 1954 (Method 1). Each year subsequent to 1954 is numbered in order (i.e. 1959 is year 5). Instead we might have considered each lease to be an independent investment. Each lease would then have had its year of lease sale defined as year 0, with net cash flows in subsequent years numbered according to number of years after the lease sale year (Method 2). A lease sold in 1960 would show its 1964 net cash flow as occurring in year 10 according to Method 1, but in year 4 according to Method 2.

To further illustrate this point, assume that one lease is sold in year 0 and a second lease is sold in year n. If the net cash flows from these leases are to be aggregated, two different procedures may be applied:

Method 1. Let the aggregate cash flow be identical to that of the first lease over years y_0 to y_{n-1}. In y_n, add the n'th cash flow entry of the first lease to the first entry of the second lease to obtain the aggregate cash flow entry. Continue by aggregating cash flows for the two leases in years y_{n+1}, y_{n+2}, etc. Under this method, the aggregate cash flow is not affected by the second lease until y_n.

Method 2. Add the year 0 cash flow entry of the first lease to the year 0 cash flow entry of the second lease and likewise for each subsequent year, with years numbered in order from zero (the year of lease sale for each lease). Under this method, all leases are treated as being sold at the same time (year 0) lending greater weight to leases sold later in the historical period than using Method 1.

Since the time profile of the aggregate cash flow will be different under the two aggregation methods, the solution for the IRR will depend on which method is chosen.[1]

Either method of computing IRR may be appropriate in light of the facts in the case. The choice should depend on the degree to which the leases can be considered independent investment projects.

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[1]It should be noted that using Method 1, IRR does not depend on whether year 0 is defined as 1954, 1959 or any other year. Our aggregate IRR is 11.43% whatever single year is called year zero.

<u>Method 1</u> is the correct choice if investments in the first through the last leases by any owner or group of owners follow each other in a non-random fashion. The r'th lease can then be considered the r'th stage of a continuous investment project.

<u>Method 2</u> is the correct choice if, for a lease owner (or group of owners), the decisions involved in buying and developing an additional lease are independent of any prior lease investments.

In truth, neither Method 1 nor Method 2 precisely reflects the facts in the present case. We believe, however, that the assumptions of Method 1 more closely approximate reality. As oil companies established themselves in the Gulf of Mexico area, knowledge was generated about important geological and economic parameters, business connections were established, and investments in fixed capital took place. The cumulative effect was to make an already established company more likely to continue investing in the Gulf of Mexico OCS. Companies generally looked upon their lease acquisitions as part of an overall strategy of investment in the Gulf of Mexico, not as a series of independent investments. Our approach has therefore been to apply the first aggregation method and thus emphasize the interdependence between successive lease investments.

If the alternative explanation of OCS investment behavior is accepted (Method 2), the overall IRR on our 1223 leases rises to 12.60%. Since we have accepted Method 1, we have not attempted to determine IRR's for all lease categories using Method 2. For individual lease sales, the IRR's are the same under Method 1 and Method 2. For other categories (i.e. wildcat versus drainage), the possible differences are suggested by the difference between 11.43% and 12.60%, as shown in the aggregate IRR's.

APPENDIX 4.

Future Price Scenarios

1. Natural gas price scenario

The Natural Gas Policy Act of 1978 provides for decontrol of "new gas" from the Outer Continental Shelf by January 1, 1985, but it requires continued controls over "old gas". New gas is defined in the Act as gas produced from a new lease, in turn defined as a lease entered into on or after April 20, 1977. Old gas is defined as gas produced from all other leases. Since all leases under study here are old leases, their gas production is subject to permanent price control as old gas.

The Act provides that the "maximum lawful price" for old gas shall be "the just and reasonable rate" established by the Federal Energy Regulatory Commission, multiplied by an inflation factor, specified as the U.S. Department of Commerce GNP implicit price deflator. This maximum may be inoperative if existing contracts call for a lower price.

The Act permits separate treatment for "rollover contracts" for gas (new contracts replacing an expiring contract). For these new contracts the Act provides for the higher of the following:

1. The just and reasonable rate as established by the FERC, multiplied by the inflation adjustment factor based on the date of the new contract, or
2. $0.54 per million BTU's for April 1977, multiplied by the inflation adjustment factor based on the same date.

We have no way of knowing what the FERC will determine to be the "just and reasonable rate" for the future. The record through 1977 indicates that the predecessor to FERC, the Federal Power Commission, determined that the weighted average price for gas produced in 1977 from leases issued from 1954 through 1969 was 53¢/Mcf. However, that rate is an average for gas committed to sales over many years beginning with first production in 1959, and includes some new sales contracts each year. Further, prices differ from tract to tract, and lease to lease. The record of natural gas selling prices for 1977 production from the 1954-1969 leases is as follows:

Lease sale date	Average price for gas produced in 1977 (dollars per M cu. ft.)	
10-13-54	0.383	
11-09-54	0.314	
7-12-55	0.602	
8-11-59	0.571	
2-24-60	0.497	
2-24-60	0.584	
3-13-62	0.546	
3-16-62	0.507	
10-09-62	0.301	
Weighted average 1954-1962		0.51
4-28-64	0.435	
3-29-66	0.490	
10-18-66	0.495	
12-15-66	0.275	
6-13-67	0.637	
2-06-68	0.541	
5-21-68	0.677	
11-19-68	0.726	
1-14-69	0.512	
12-16-69	0.439	
Weighted average 1964-1969		0.57
7-21-70	0.549	
12-15-70	0.980	
11-04-71	0.839	
9-12-72	0.714	
12-19-72	1.404	
6-19-73	1.542	
6-19-73	1.430	
12-20-73	0.691	
3-28-74	1.051	
10-15-74	1.121	
Weighted average 1970-1974		1.04

The tabulation of actual selling prices shown above illustrates two points: (1) The great variability in average price highlights the difficult problem of predicting how federal regulators will set future prices as they interpret the "just and reasonable rate" rule. (2) The great variability in the more recent years (say from 1970 through 1974) illustrates a "noise factor." Due to accounting procedures, annual accounting for the volume of production does not always correspond with the accounting for revenue. This practice creates some erroneous unit price results in specific years.

Under the first principle above, the "just and reasonable" rate for rollover gas from old production (not new gas) is not subject to precise estimation. We will arbitrarily assume that under this principle, half of the rollover gas is priced at $1.00/Mcf in 1977.

Under the second principle, 54¢/Mcf would prevail for the other half of the rollover gas in April 1977. The average of these two prices is 77¢ for 1977. Since we have no principle for distinguishing one base from another with respect to rollover pricing, the average value will be used. It is subject to price escalation and becomes 90¢/Mcf in 1979. This is the price we have used for rollover gas in Table 31 for 1979. The prices allowed under the rollover provision are apparently intended to be more attractive than prices under continuing contracts.

For the non-rollover gas, we will begin with a 1978 price equal to the actual price by lease.[1] We cannot simply project the past rate of price increase because that record reflects some new production entering at prices well above the average of all prior contracts. Our production

[1]The 1978 lease-specific gas price used as a forecasting base is constrained to a minimum of 15¢/Mcf and a maximum of $1.80/Mcf to eliminate illogically low or high average gas prices resulting from USGS accounting corrections made on some leases each year.

Table 31

FUTURE PRICES FOR NATURAL GAS (LEASE-SPECIFIC)

	Percent of gas production under rollover pricing	Price for rollover gas $/Mcf.	Percent of gas production under non-rollover pricing	Price for non-rollover gas $/Mcf. [1]
1978	0.0		100.0	1978 price
1979	3.125	0.90	96.875	1.086
1980	6.250	0.97	93.750	1.168
1981	9.375	1.04	90.625	1.252
1982	12.500	1.11	87.500	1.339
1983	15.625	1.19	84.375	1.434
1984	18.750	1.27	81.250	1.532
1985	21.875	1.35	78.125	1.622
1986	25.000	1.42	75.000	1.714
1987	28.125	1.51	71.875	1.820
1988	31.250	1.61	68.750	1.934
1989	34.375	1.70	65.625	2.049
1990	37.500	1.79	62.500	2.161
1991	40.625	1.89	59.375	2.276
1992	43.750	1.99	56.250	2.403
1993	46.875	2.11	53.125	2.539
1994	50.000	2.23	50.000	2.684
1995	53.125	2.36	46.875	2.840
1996	56.250	2.49	43.750	3.006
1997	59.375	2.64	40.625	3.184
1998	62.500	2.80	37.500	3.374
1999	65.625	2.97	34.375	3.576
2000	68.750	3.15	31.250	3.793
2001	71.875	3.34	28.125	4.020
2002	75.000	3.54	25.000	4.262
2003	78.125	3.75	21.875	4.517
2004	81.250	3.97	18.750	4.788
2005	84.375	4.21	15.625	5.076
2006	87.500	4.47	12.500	5.380
2007	90.625	4.73	9.375	5.703
2008	93.750	5.02	6.250	6.045
2009	96.875	5.32	3.125	6.408
2010	100.0	5.64	0.0	6.792

[1] For 1979 and each year thereafter, price by year is the 1978 price multiplied by the annual GNP deflator (÷ 100) as shown.

scenario assumes no new production from 1954-1969 leases beyond the year 1978. Therefore, we will apply the "annual inflation adjustment factor" (the GNP deflator) utilized in the Act for all production in our forecast. For this purpose the Chase Econometrics, Inc., long-term forecast (to the year 2000) for the GNP deflator will be used (see Table 32).

Table 32.

FORECAST OF FUTURE PRICE INFLATION[1]

1978 = 100.0	1994 = 268.4
1979 = 108.6	1995 = 284.0
1980 = 116.8	1996 = 300.6
1981 = 125.2	1997 = 318.4
1982 = 133.9	1998 = 337.4
1983 = 143.4	1999 = 357.6
1984 = 153.2	2000 = 379.3
1985 = 162.2	2001 = 402.0
1986 = 171.4	2002 = 426.2
1987 = 182.0	2003 = 451.7
1988 = 193.4	2004 = 478.8
1989 = 204.9	2005 = 507.6
1990 = 216.1	2006 = 538.0
1991 = 227.6	2007 = 570.3
1992 = 240.3	2008 = 604.5
1993 = 253.9	2009 = 640.8
	2010 = 679.2

[1]Chase Econometrics, Inc., Long-Term Macroeconomic Forecasts, 1979, for the years through 2000. Thereafter, the Chase forecast has been projected through the year 2010 at a 6 percent annual rate of inflation.

To summarize, we must forecast three categories of old gas prices as follows:

1. Non-rollover gas--"just and reasonable rate", plus inflation adjustment.
2. Rollover gas--54¢/Mcf in 1977, plus inflation adjustment, or
3. Rollover gas--"just and reasonable rate" plus inflation adjustment.

We will resolve the two rollover categories into one having an average 1979 price of 90¢/Mcf. Non-rollover gas will be based on the actual 1978 price. Both classes will be escalated by the GNP deflator.

Since we have no data on the magnitude of probable volumes of gas covered by the rollover provision, we will assume a straight line relationship from zero rollover volume in 1978 to 100 percent of total production in 2010. This model is shown in Figure 10.

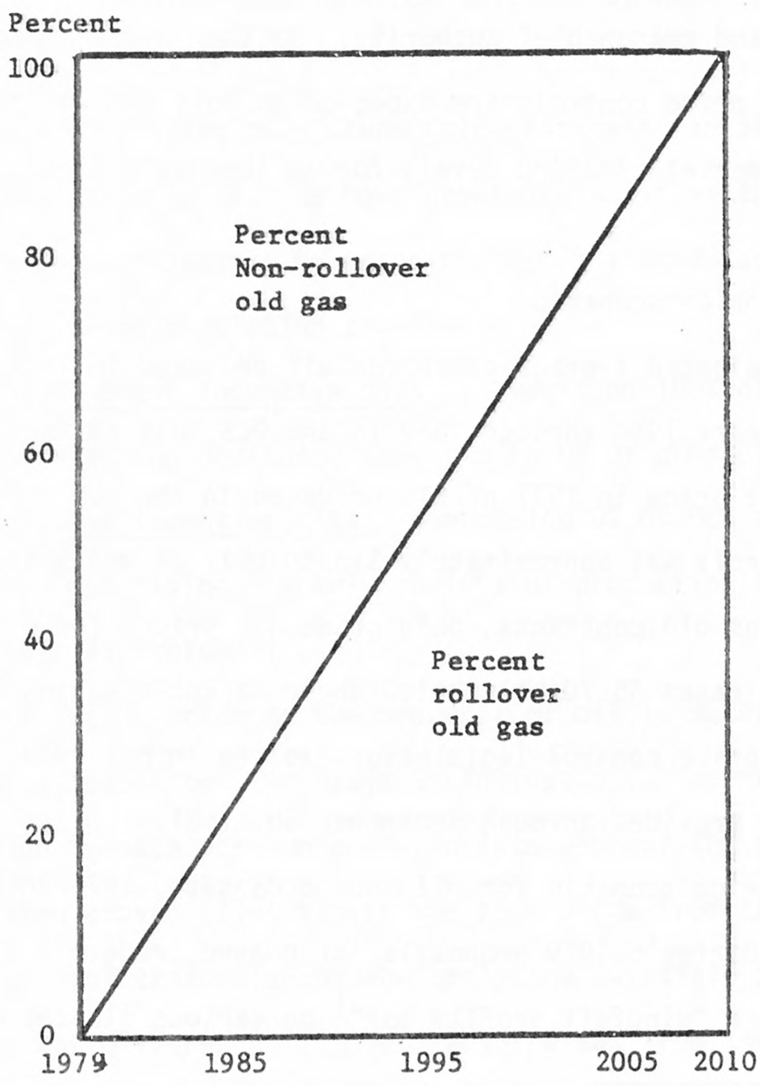

Figure 10. Assumptions about relative shares of rollover and non-rollover old gas.

Congress apparently intended under the new Act that the price for old OCS gas would remain below the market clearing level. With the price of a close substitute, No. 2 fuel oil, at 37¢/gallon (mid-1977), the implied value of natural gas including a cleanliness premium, would be approximately $2.80/Mcf (mid-continent, wholesale). With the base price of gas in 1977 set below $1.00/Mcf and price escalation limited to the GNP deflator, the only possibilities for natural gas prices rising to market clearing levels would be (1) for the price of crude oil and fuel oil to fall sharply, or (2) for the FERC to substantially increase the price of natural gas under its "just and reasonable" authority. Neither event appears to be likely. Therefore, price controls are expected to hold the wellhead price of natural gas below market clearing levels for as long as old gas is produced from the OCS.

2. Crude oil price scenario

The weighted average price for oil produced in 1977 from leases issued over the years 1954 through 1969 in the OCS Gulf of Mexico was $7.80/barrel. The average price in 1977 of oil produced in the U.S. but not subject to price controls was approximately $13.50/bbl. at wellhead. Thus, the control system, plus old contracts, held crude oil prices for oil produced from the 1954-1969 leases $5.70/bbl. below their market-clearing level. Present crude oil price control legislation expired in May 1979, with Presidential discretion provided through September 30, 1981.

Our price scenario for oil and condensate, 1979-2010, is based upon President Carter's 1979 proposals for phased crude oil price decontrol combined with a "windfall profits tax"[1] on various classes of oil. This tax

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[1] In fact, the tax is an excise tax to be imposed on the difference between the selling price of oil and an arbitrarily determined "base price". The tax is not a function of profits; costs of production are totally ignored in the formulation.

is to be applied at a proposed rate of 50% to the difference between the actual selling price of the oil and an arbitrary base price which is set by federal regulations. Obviously, the higher the base price, the smaller the amount of tax for any given selling price. Because virtually all oil produced from the leases in our study will be classified as "old oil", we assume that none of this oil will be exempt from the "windfall profits tax". We assume further that oil produced from OCS leases becomes uneconomic before it can fall into the stripper category. This means that OCS oil cannot achieve exemption from this tax by means of declining production.

The data underlying our future price forecast for oil and condensate are presented in Table 33. We have greatly simplified the President's decontrol and tax proposals by assuming that oil produced from the OCS will fall into two price-regulation classes:

1. A non-market incentive class, comprising 100% of OCS production in 1979, and declining linearly to 0% of production in 1991, and
2. A market incentive class, comprising 0% of OCS production in 1979 and rising linearly to 100% of production in 1991 (see Table 33, column 1).

The net future price to the producer of oil is determined in our scenario on a lease-specific basis as follows: (1) determine the proportion of production in each year which falls into each of the two price-regulation classes listed above; (2) subtract the base price from the selling price of oil in each of these classes and apply the "windfall profits tax" at a 50% rate to the difference; (3) subtract the tax from the selling price for each class of oil; (4) multiply the net-of-tax selling price of oil in each class by the quantity of oil in each class; and (5) sum the net-of-tax

TABLE 33.

OIL AND CONDENSATE PRICE FORECAST

Year	Percent in Market Incentive Class	Base Price in Non-Market Incentive Class (applicable 1979-1991)	Selling Price for Non-Market Incentive Class (applicable 1979-1991)	Market Incentive Class Base Price (applicable 1990-2010)	Market Incentive Class Selling Price (applicable 1980-2010)
1979	0	*	**	-	-
80	10	*	**	16.83	28.00
81	20	*	**	18.04	28.00
82	30	16.27	19.29	19.29	29.95
83	40	17.42	20.66	20.66	32.07
84	50	18.61	22.06	22.06	34.26
1985	60	19.83	23.38	23.38	36.27
86	70	20.83	24.69	24.69	38.33
87	80	22.11	26.22	26.22	40.70
88	85	23.50	27.86	27.86	43.25
89	90	24.90	29.53	29.53	45.82
1990	95	26.26	31.12	31.12	48.33
91	100			32.79	50.90
92	100			34.61	53.74
93	100			36.59	56.78
94	100			38.67	60.03
1995	100			40.92	63.51
96	100			43.31	67.23
97	100			45.87	71.21
98	100			48.61	75.39
99	100			51.52	79.97
2000	100			54.64	84.93
01	100			57.93	89.90
02	100			61.40	95.32
03	100			65.08	101.02
04	100			68.98	107.08
2005	100			73.12	113.52
06	100			77.51	120.32
07	100			82.15	127.54
08	100			87.09	135.18
09	100			92.32	143.31
2010	100			97.85	151.90

*1979-81 base price frozen at 1978 lease-specific price.

**For each year 1979-81, selling price in 1978 is increased by one-fourth of the difference between the 1978 price and the 1982 price ($19.29).

Note 1: The price of a particular barrel for a particular lease is a weighted average of the price in the non-market incentive class (adjusted for tax) and the market incentive class price (adjusted for tax). The weights are the percentages of production in each class.

Note 2: In each category (market incentive or non-market incentive) a 50 percent tax rate has been applied on the difference between the selling price and base price in that category ("excess profits tax"). Tax is applied for years 1980-2010 (<u>no</u> tax for 1979).

revenue from oil in each class to determine future annual oil and condensate revenue for each lease. All lease-specific production costs (including royalties) must then be subtracted from annual lease revenues to determine future net cash flows by year.

The final part of this scenario involves the determination of selling prices and base prices in each of the price-regulation classes. This is done as follows:

<u>For the market incentive class</u>:

<u>Selling price</u> is based upon import prices prevailing in mid-1979, $28.00/bbl. This price is fixed for 1980 and 1981, then escalated for 1982 and beyond using the Chase Econometrics forecast for the GNP deflator as shown in Table 32. (See Table 33, column 5).

<u>Base price</u> will reflect the President's proposed base price of $16.00/bbl. as of Jan. 1, 1980, escalated to mid-year 1980. Base price in 1981 and beyond is 1980 base price escalated by the GNP deflator. (See column 4.)

<u>For the non-market incentive class</u>:

<u>Selling price</u> in 1979-81 is equal to 1978 price increased in each year by one-fourth of the difference between the lease-specific 1978 price and $19.29/bbl.[1] The 1982-90 selling prices are equal to the 1982-90 base prices for market incentive class oil, as in the President's proposal. There

[1]This is the 1982 base price for market incentive class oil. Lease-specific prices for oil and condensate in 1978 were constrained to a maximum of $15.00/bbl. and a minimum of $5.00/bbl. to eliminate illogically high or low average prices created by USGS accounting corrections made for some leases each year.

is no non-market incentive oil in 1991 and beyond. (See column 3.)

Base price for years 1979-81 is equal to lease-specific 1978 price. 1982 base price is $16.27/bbl., computed by escalating the April 1979 controlled price for upper tier oil ($13.00/bbl.) using GNP deflator forecast, as in the President's proposal. Base price in 1983-90 is 1982 base price escalated as before noted. (See column 2.)

We have provided alternative price scenarios for the years beyond 1978 in order to test the sensitivity of IRR to different rates of future price inflation. The results of these sensitivity tests are reported in Part I, above.[1] These tests were performed using the standard price forecasts described in this Appendix, but increased or decreased by fixed percentages in each year, as follows:

1. Standard price forecast plus 50 percent.
2. " " " " 40 "
3. " " " " 30 "
4. " " " " 20 "
5. " " " " 10 "
6. " " " minus 10 percent.

[1] All of our profitability (IRR) estimates are computed on a before-tax basis with the exception that the "windfall profits tax" is explicitly deducted from future gross revenue for each lease.

APPENDIX 5.

Glossary of Lease-Specific Variables Used in Regression Analysis

AWELLDEP: Average well depth in feet (variable used in regressions involving productive leases only).

BIG801: Dummy variable. For solo-bid leases, BIG801=1 if the winning bidder is a Big-8 firm, zero otherwise. For joint-bid leases, BIG801=1 if any of the winning joint bidders is a Big-8 firm, zero otherwise.

B8DJ: Dummy variable. B8DJ=1 for drainage leases won by a joint bidder where at least one of the winning joint bidders is a Big-8 firm, zero otherwise.

B8DS: Dummy variable. B8DS=1 for drainage leases won by a Big-8 solo bidder, zero otherwise.

B8WJ: Dummy variable. B8WJ=1 for wildcat leases won by a joint bidder where at least one of the winning joint bidders is a Big-8 firm, zero otherwise.

B8WS: Dummy variable. B8WS=1 for wildcat leases won by a Big-8 solo bidder.

DSTATE: Dummy variable. DSTATE=1 for leases other than offshore Louisiana, zero for offshore Louisiana leases.

DWILDDR: Dummy variable. DWILDDR=1 for drainage leases, zero for wildcat leases.

GAS01: Dummy variable. GAS01=1 for productive leases where the BTU content of gas production in the historical period (through 1978) exceeds that of oil and condensate production. Definition assumes 1 bbl. oil (or condensate)=5.68 mcf. gas in BTU content.

JOINT01: Dummy variable. JOINT01=1 for leases won by a joint winning bidder, zero for solo winning bidder.

LNACRES: Natural logarithm of the number of acres in a lease.

LNBONPA: Natural logarithm of the bonus (in dollars) per acre.

LNHIGHBD: Natural logarithm of the bonus (in dollars) per lease.

LNNBIDS: Natural logarithm of the number of bids submitted for a lease.

LNPVPDV: Natural logarithm of the present value of production (in dollars) from sale date through 1978, discounted at 10 percent.

LNWATDEP: Natural logarithm of the average water depth (in feet).

LNWELL24: Natural logarithm of the number of wells drilled in the first 24 months following lease sale.

NB8DJ: Dummy variable. NB8DJ=1 for a drainage lease won by a joint bidder where none of the winning joint bidders was a Big-8 firm, zero otherwise.

NB8DS: Dummy variable. NB8DS=1 for a drainage lease won by a non-Big 8 solo bid, zero otherwise.

NB8WJ: Dummy variable. NB8WJ=1 for a wildcat lease won by a joint bid where none of the winning bidders were a Big 8 firm, zero otherwise.

NB8WS: Dummy variable. NB8WS=1 for a wildcat lease won by a non-Big-8 solo bidder.

OIL01: Dummy variable. OIL01=1 for productive leases where the BTU content of oil and condensate production in the historical period (through 1978) exceeds that of gas production. Definition assumes 1 bbl. of oil (or condensate)=5.68 mcf. gas.

PROD01: Dummy variable. PROD01=1 for productive leases, zero otherwise.

S550712: (etc.) Dummy variable. S550712=1 for leases sold 07/12/55, zero otherwise. Other sale dummy variables are treated analogously (i.e. sale dates are listed SYYMMDD, for year, month and day of the lease sale).

TOFIRSTG: Number of months following sale date to first production of gas on a lease.

TOFIRSTO: Number of months following sale date to first production of oil (or condensate) on a lease.

TOMAXG: Number of months following sale date to maximum recorded gas production on a lease.

TOMAXO: Number of months following sale date to maximum recorded production of liquids (oil plus condensate) on a lease.

YOS: Year of lease sale, with 1954 defined as year 0.

APPENDIX 6.

The Relationship Between Number of Bidders and High Bid

Number of bidders has been shown to have a positive and significant influence on high bid in our analysis (Part III, models 1-3). Some reviewers of our Interim Report argue that this relationship may be spurious. Their argument is generally as follows: The perceived quality of a lease influences both high bid and number of bidders. If this is the case, then high bid and number of bidders are simultaneously determined. Neither variable can be said to explain the other.

We have attempted to test the proposition that the number of bidders depends upon the perceived quality of the lease plus a number of other variables. The most satisfactory of the equations we used to test this proposition is that referred to as Model A below. This model is similar to Model 1 (our basic regression model for high bid) but with two exceptions:

1) LNNBIDS is now the dependent variable; and

2) LNHIGHBD is excluded from the model.

Model A is a poor one in ability to explain variation in the number of bidders (R^2 = .2456). But every other reasonable set of variables we might have used to explain LNNBIDS performed even more poorly. It should be noted that LNNBIDS is significantly influenced by LNPVPDV, indicating that number of bidders is affected by the perceived quality of the lease. This fact tends to support the argument that high bid and number of bidders are, to some degree at least, simultaneously determined. It is also true, however, that number of bidders has an independent influence on high bid, reflecting the intensity of competition. In any bidding situation, the addition of one more bid cannot reduce the size of the high (winning) bid; it always may, and sometimes will, increase the high bid.

We conclude that number of bidders is both an independent force influencing the size of high bid and a variable which is to some extent dependent upon the perceived quality of the lease. This creates problems for econometric estimation when LNNBIDS is used as an independent variable, the most serious being that the coefficient estimates in the affected models may be biased.

Econometric techniques exist which are designed to reduce these problems. We have used a technique called two stage least squares estimation. In this approach, a first stage regression is run to estimate the value of LNNBIDS, using a variety of independent variables (excluding LNHIGHBID). In the second stage of the analysis, LNHIGHBID is the dependent variable and the predicted value of LNNBIDS (derived from stage 1) is used as one of the independent variables.

The best first stage model we have been able to specify using the variables at our disposal is that shown as Model A. The second stage model is called Model B. The latter is identical to regression Model 1 (Part III) except that the predicted values of LNNBIDS have been substituted for the observed values. In comparing Model B with Model 1, it can be seen that (1) the R^2 is much lower, and (2) LNPVPDV is now insignificant. The predicted value of LNNBIDS is now the most important independent variable explaining high bid.

If Model B is a better representation of reality than Model 1, then we must conclude that an additional bidder for a lease will generate a larger increase in high bid than is indicated by Model 1. But we do not believe that the two stage approach is more valid than our basic Models 1-3 because the first stage (Model A) is a poor predictor of number of bidders and, more importantly, because it is theoretically hard to accept the conclusion that the ultimate productivity of a lease (LNPVPDV) has an insignificant influence on high bid.

We conclude that number of bidders is more properly modeled as an independent variable in our analysis, although we have not been able to eliminate the probable element of simultaneity between LNHIGHBID and LNNBIDS in our equations. A good argument can be made that, even given this problem of simultaneity, the ordinary least squares method of estimation still compares favorably with other, more elaborate, econometric techniques.[1] Thus we have consistently applied ordinary least squares methods in all of our regressions. But the reader should note that the contribution of LNNBIDS may be understated in our regressions with LNHIGHBID as the dependent variable.

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[1]See, for example, G. Maddala, Econometrics, McGraw-Hill, 1977, p. 231.

Model A

Dependent Variable: Log of Number of Bidders
R^2 = .2456

Variable	Parameter Estimate	T-Ratio
INTERCEPT	-0.440358	-1.0324
LNPVPDV	0.012007	3.9011*
LNACRES	0.090360	1.7689
LNWATDEP	0.121697	3.6639*
LNWELL24	0.314238	9.4418*
JOINT01	0.207430	4.5859*
BIG801	0.007553206	0.1700
S550712	-0.109533	-1.1892
S590526	-1.130628	-6.8754*
S590811	-0.418975	-2.3117*
S600224	-0.350955	-3.9765*
S620313	-0.442174	-5.2276*
S620316	-0.237843	-2.8367*
S621009	-0.595361	-2.4215*
S640428	-0.189641	-1.0978
S660329	-0.208724	-1.1161
S661018	-0.526618	-3.3555*
S670613	-0.095117	-1.0159
S680521	0.150004	1.5377
S681119	-0.652791	-3.3991*
S690114	-0.886975	-5.1246*
S691216	-0.597248	-3.1995*

Model B

Dependent Variable: Log of High Bid
R^2 = .4933

Variable	Parameter Estimate	T-Ratio
INTERCEPT	6.724801	11.4692*
B001.LNBIDS	1.974037	14.2712*
LNPVPDV	0.0004031618	0.0844
LNACRES	0.636210	8.7845*
LNWATDEP	-0.137672	-2.9119*
LNWELL24	0.289287	4.1130*
JOINT01	0.025129	0.3512
BIG801	-0.022509	-0.3391
DWILDDR	1.433962	11.2157*

*Significant at 5% level (two-tailed test).

APPENDIX 7.

Rejected Regression Analysis Approaches.

A number of regression models other than those reported in Parts III and IV of this report were estimated. Formulations with other dependent as well as independent variables were tried, but with unsatisfactory results. Some of these alternative formulations are discussed in this appendix.

1. Additional Independent Variables in High Bid Models.

We have not reported the results of tests of certain hypothesized relationships between LNHIGHBD and the independent variables listed below because these variables added little or nothing in the way of additional predictive power to the main regressions reported. In certain cases the variables were highly correlated with existing independent variables. In other cases the variables had either important measurement problems or were not significant. These variables are:

a) Average Well Depth (AWELLDEP)

As the depth of wells drilled on a tract increases, the costs of drilling and development increase. If firms are able to forecast well depths on tracts they bid for with reasonable accuracy, one would expect (*ceteris paribus*) a negative relationship between high bid and average well depth.

The variable AWELLDEP is, however, highly correlated with the variable LNPVPDV (present value of production) if we set AWELLDEP = 0 for leases that were never drilled.[1] This creates serious problems of estimation. To better test the significance of AWELLDEP, we ran regressions using only those leases which were *drilled*. In these regressions AWELLDEP had no predictive power. When a separate form of the variable (AWELLDEP squared) was tried, it also proved to have the same problems. AWELLDEP was therefore omitted from the regression analysis of high bids, though it was retained as an explanatory variable in the regression models for expeditious development (observations on productive leases only).

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[1]Strictly speaking, AWELLDEP is *undefined* for leases which were never drilled. Thus, the convention of setting AWELLDEP equal to zero for such leases in itself creates some logical inconsistency.

b) Alternative Definitions of Value of Production

One potential problem with the LNPVPDV variable is that it will measure up to 24 years of production for the early leases in the data base, but only 9 years for the last leases included. In order to overcome this problem, a new variable was created, calculated as the average yearly value of production from lease sale through 1978 (with adjustments for the fact that later leases reached production faster). This formulation (replacing LNPVPDV with the new variable in the regression analysis) resulted in essentially no impact on the regression analysis results. For this reason, we retained the LNPVPDV variable in our analysis. We hypothesized that leases which were expected to produce mostly oil might have different expected costs than leases which were expected to produce mostly gas. Consequently, firms might bid different amounts for a lease depending on whether the lease was expected to be an oil or a gas lease. We tried using variables which distinguished between oil and gas leases on a BTU basis as well as on an oil/gas value of production basis. However, these approaches did not show an improvement in the estimated equations relative to the simpler variable LNPVPDV. Therefore, these approaches were rejected.

c) Prorationing Variable

Firms bidding on leases are concerned with the expected level of production and price received for output. If the level of output is restricted by market demand prorationing (offshore output is influenced by the Louisiana market demand prorationing factors) both output and price of output are affected. Hence we hypothesized that firms might adjust bids according to the expected level of market demand prorationing. However, in our tests using the prorationing factor for the year of the sale (average of the monthly values for Louisiana), there was no significant impact of market demand prorationing on the amount bid over different lease sales. This variable is also highly correlated with year of sale. Thus the variable was omitted from the analysis.

d) Geometric Mean of Bids, Excluding High Bid

We hypothesized that high bids would increase for those leases where there was general agreement among bidders that the leases were of "higher quality". The average perceived quality level can be measured by taking the geometric mean of the bids received on a lease, excluding the winning bid. This variable was, however, highly correlated with the number of bids received on a lease and was therefore omitted.

e) Geographic Location

i) Differences between states in past production history, geological conditions, cost conditions, and/or market demand prorationing factors may cause firms to bid different amounts for leases depending on geographic location. A dummy variable was defined to distinguish offshore Louisiana leases from leases in other areas. However, the variable was not significant and was therefore rejected in the regression analysis of high bids.

ii) East versus West Louisiana. It was hypothesized that because of a substantial difference in the gas/oil ratios of production, there may exist differences in bidding for east versus west Louisiana leases. A dummy variable was therefore created to differentiate between the east versus west Louisiana leases. This avenue of analysis was not particularly fruitful, especially when states other than Louisiana were included in the regressions. Even in regressions run only on Louisiana leases, the variable was not significant at the 5% level.

f) Bidder Bias or Firm Aggressiveness

USGS has used a measure of bidder bias (f_B) in an attempt to quantify possible differences in firm bidding behavior.[1] The variable used is the ratio of: a) the sum of the number of firms that bid lower than the firm in question on those leases for which that firm submitted bids, to b) the sum of the number of bids on the tract the firm bid on minus one. The values of this variable would range from zero (the firm bid lower on all leases than other firms) to one (the firm bid higher on all leases than other firms). The USGS analysis notes that "...bidders display wide variations in aggressive/conservative stance in individual sales. If any bidder did have a purposeful strategy of being aggressive or conservative, he was not able to steer a steady course." This observation is consistent with the hypothesis that the f_B variable is really only a random variable. Under this hypothesis, those firms with large numbers of bids would tend to have f_B values close to the mean (0.5) while those firms which submit few bids would be expected to have more extreme values (closer to either zero or

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[1]See U.S. Geological Survey. SAD Section Report No. 77-26, 7/15/77.

one). This is precisely the result that occurs when the distribution of f_B values, with respect to the number of bids submitted, is analyzed. For this reason the f_B value of the winning bidder was rejected as an explanatory variable in the regression analysis of high bid.

g) Present Value of Lease.

In the absence of uncertainty, and given effective competition for leases and a perfect capital market, the high bid for a lease would be equal to its present value (excluding the bonus payment). As the present value of the lease (net of bonus) increases, one would expect the high bid to increase and vice versa. To determine the extent to which OCS bids reflect ex post present values for leases, an independent variable measuring present value of the lease at date of lease sale was tested, using a 10 percent discount rate. This present value measure was defined in both logarithmic and non-logarithmic form. A third variable was computed as the ratio of present value to high bid. None of these formulations was capable of improving high bid models in terms of explanatory power. Also, they had an adverse effect on the sign and significance of other independent variables included in the models. The arbitrariness involved in selecting an appropriate discount rate as well as the results of the regressions led us to reject present value formulations as independent variables.

2. Regression Models with Profitability Measures as Dependent Variables.

Attempts were made to formulate regression models that could explain the profitability of leases to lessees. The dependent variable could be either the IRR or the present value of the lease. There are, however, problems with both of these measures when used for regression analysis.

a) IRR as Dependent Variable.

Our IRR analysis has shown that there are differences in IRR's between lease categories (firm size, solo/joint, wildcat/drainage etc). It is of interest to ask whether these differences are statistically significant. One way of testing for significance is to use regression analysis with IRR as dependent variable and explanatory variables corresponding to the lease categories (and, maybe, a set of other explanatory variables). But there are problems with the IRR measure which makes it unsuitable for regression analysis. Of the leases under study, 76.8 percent have an IRR which is less than zero. It can be shown that profitability ranking of leases based on IRR is meaningless when the IRR is negative. A simple example will illustrate this. Assume that there are only two leases under consideration and that the cash flows associated with each of them are as shown in Exhibit 1.

EXHIBIT 1.

NET CASH FLOWS OF TWO HYPOTHETICAL LEASES.

	Year			Present Value	
	0	1	2	(10% Discount Rate)	IRR
Lease A	-10	+8	0	-2.72	-20%
Lease B	-10	0	+8	-3.39	-11%

Lease A is clearly a better investment in that it receives its income earlier and has a higher (although still negative) present value than Lease B. But it has a lower (more negative) IRR--a contradiction of economic logic. Thus we must conclude that IRR's provide an inappropriate standard of comparison between leases with negative IRR's. Furthermore, IRR is undefined when there are no positive entries in the net cash flow.

The fact that regression analysis with IRR as the dependent variable could be meaningfully applied to only 23.2 percent of the 1223 leases being studied, would severely limit the relevance and generality of conclusions from the analysis. Consequently, we chose not to conduct that analysis.[1]

b) Present Value as Dependent Variable.

The present value of a lease, in contrast to the IRR, will give a meaningful ranking of leases even if it is negative. But the ranking will depend on the choice of the discount rate. A high discount rate will favor

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[1]The same argument applies to the use of IRR as an independent variable and, in general, to the use of IRR's of individual leases in <u>any</u> statistical test.

leases with an "early" cash flow and vice versa. In formulating present value measures, we chose a discount rate of 10%, discounted the net cash flow to lease sale date, and subtracted the bonus payment. From this computation, we could derive two additional measures: (1) log. of present value (to reduce the effect of extreme values); and (2) ratio of present value to high bid (to abstract from the scale of the cash flow--as the IRR measure does). Neither of these measures, used as a dependent variable, worked satisfactorily. The explanatory power of the estimated equations (R^2) was in the range of 10 percent to 20 percent. The sign and significance of the explanatory variables indicated that there was a specification problem. The present value of the leases therefore could not be explained by any set of variables at our disposal. In other words, there is a very large element of variation in the profitability of leases (as measured in present value terms) which could not be accounted for. The estimated models are not reported since interpretations or conclusions drawn from them would necessarily have little or no empirical relevance.

APPENDIX 8.

Listing of Data Tables

TABLE 34.

LEASING RESULTS FOR THE TWENTY LARGEST FIRMS RANKED BY ACREAGE

ATTRIBUTED SHARES OF 1223 OCS LEASES

Rank By Acre-age	Company	Acres Leased Through 1969	Number of Leases Acquired Through 1969	Gross Value of Production Through 1978 ($M)	IRR (%)	Gas/Oil Ratio BTU Basis Through 2010	Gas Revenue as a Percent of Total Lease Revenue	Average Bonus ($M) Per Lease	Percent of Total Production Value of All Leases Through 1978	Percent of Total Production Value of All Leases Through 2010	Average Lag in Years from Sale to First Production on Productive Leases
1	Shell	754, 110	165	3, 205, 726	10. 84	. 69	16. 6	1, 852	17. 1	14. 2	3. 81
2	Std. Oil Cal.	575, 685	146. 75	1, 361, 090	10. 6	. 86	28. 6	1, 159	7. 6	7. 5	5. 74
3	Exxon	481, 448	106. 57	1, 755, 090	14. 02	. 79	28. 6	2, 961	9. 8	8. 5	4. 91
4	Gulf	430, 883	94. 61	2, 041, 636	11. 35	. 88	23. 0	2, 411	11. 4	9. 9	3. 45
5	Texaco	324, 806	69. 5	590. 600	3. 37	1. 87	41. 8	5, 189	3. 3	3. 5	5. 04
6	Forest	269, 453	57. 0	465, 636	10. 09	8. 56	72. 0	973	2. 6	3. 0	9. 29
7	Continental	213, 416	51. 28	537, 273	12. 06	1. 95	44. 4	1, 646	3. 0	3. 6	2. 26
8	Union	204, 523	44. 96	1, 020, 819	15. 32	3. 06	54. 5	3, 217	5. 7	5. 8	3. 47
9	Mobil	204, 418	46. 95	590, 600	11. 06	3. 87	56. 5	3, 033	3. 3	3. 3	2. 90
10	Std. Oil Ind.	203, 629	49. 28	626, 819	11. 38	2. 1	37. 5	1, 215	3. 5	3. 8	4. 96
11	Sun	202, 103	49. 39	89, 545	7. 77	1. 41	33. 3	562	. 5	. 7	1. 20
12	Arco	199, 209	46. 44	770, 091	12. 70	1. 25	33. 3	1, 997	4. 3	5. 2	1. 80
13	Tenneco	179, 530	42. 48	949, 181	14. 34	6. 06	73. 7	2, 343	5. 3	6. 2	6. 37
14	Getty	130, 596	32. 60	608, 909	13. 24	3. 1	54. 5	2, 454	3. 4	3. 3	1. 38
15	Cities	125, 597	30. 53	573, 091	12. 48	2. 02	44. 4	3, 370	3. 2	3. 3	1. 35
16	Phillips	122, 230	30. 76	268, 636	4. 52	1. 51	23. 0	2, 474	1. 5	1. 5	4. 96
17	Placid	87, 187	24. 97	197, 000	11. 35	. 40	9. 0	1, 009	1. 1	1. 6	4. 98
18	Superior	70, 454	20. 99	179, 091	8. 48	6. 46	64. 0	1, 232	1. 0	. 9	5. 23
19	Murphy	60, 036	12. 50	214, 909	20. 88	3. 05	52. 0	391	1. 2	1. 7	7. 75
20	Kerr-McGee	54, 511	14. 24	268, 636	12. 10	. 86	23. 0	1, 477	1. 5	1. 3	4. 03
21	Pennzoil	38, 779	9. 75	28, 177	Neg.	1. 90	62. 0	2, 356	0. 1	0. 1	
22	Amerada Hess	32, 254	6. 89	324, 513	17. 46	. 51	15. 1	6, 595	1. 8	2. 2	
23	Marathon	29, 150	6. 57	222, 968	12. 18	. 69	16. 5	8, 075	1. 2	1. 5	
24	Roy Lee	24, 993	6. 0	32, 236	7. 23	2. 62	39. 1	229	0. 2	0. 2	
25	La. Land & Exp.	23, 467	5. 89	218, 849	16. 66	. 70	18. 6	7, 340	1. 2	1. 6	
Other Big-20 Firms (As Ranked by 1969 Sales)											
	Std. Oil Ohio	21, 994	5. 0	-0-	Neg.	-0-	-0-	299	-0-	-0-	
	Signal	19, 995	4. 38	130, 199	15. 07	1. 06	24. 8	7, 277	0. 7	0. 9	
	Occidental	1, 789	0. 50	1, 612	11. 07	1. 88	41. 1	1, 878	0. 0	0. 0	
	Ashland	158	0. 12	358	6. 34	1. 74	39. 6	1, 179	0. 0	0. 0	

TABLE 35.

INTERNAL RATE OF RETURN BY LEASE SALE

	Sale Type[1]	IRR (%)	No. of Leases Issued	No. of Dry Leases	Percent Dry Leases	Gas/Oil Ratio (BTU's)	Average No. of of Bidder Per Lease Issued	Ratio of Solo Bid Leases to Joint Bid Leases	Average Bonus Per Lease Issued ($M)
Aggregate		11.43	1223	757	61.89	1.40	3.33	2.39	2,228
SALE DATE									
10-13-54	W	6.88	90	40	44.4	.38	3.63	4.29	1,293
11-09-54	W	Neg.	19	13	68.4	9.51	4.74	2.17	1,229
07-12-55	W	8.48	121	91	75.2	2.49	3.17	2.78	897
05-26-59	W	Neg.	23	23	100.0	-	1.0	0.05	74
08-11-59	D	7.60	19	6	31.6	1.00	2.37	2.17	4,633
02-24-60	W	14.79	147	79	53.7	3.13	2.82	1.72	1,923
03-13-62	W	13.38	206	123	59.7	1.38	2.59	4.02	860
03-16-62	W	12.77	205	129	62.9	1.37	3.22	3.88	1,309
10-09-62	D	14.38	9	5	55.6	2.55	2.33	2.0	4,876
04-28-64	D	21.26	23	8	34.8	1.63	3.00	3.1	2,629
03-29-66	D	21.91	17	4	23.5	.86	3.71	1.83	5,226
10-18-66	D	13.96	24	10	41.7	1.17	2.92	1.18	4,132
06-13-67	W	10.74	158	107	67.7	.51	4.6	1.36	3,228
05-21-68	W	Neg.	110	94	85.5	9.53	4.75	2.44	5,417
11-19-68	D	21.13	16	8	50.0	.69	2.06	1.67	9,367
01-14-69	D	13.70	20	11	55.0	1.19	1.70	1.5	2,201
12-16-69	D	20.82	16	6	37.5	1.04	3.63	3.0	4,182
Louisiana Leases Issued in 1954 and 1955		7.84	184			4.94	3.68	3.18	1,176

[1] W = Wildcat Sale D = Drainage Sale

Table 36.

Aggregate Net Cash Flow by Years
1223 Leases

Year	Net Cash Flow	Year	Net Cash Flow
1954	-159493629.00	1983	1289644722.32
1955	-143609031.37	1984	1180211172.57
1956	-38114457.18	1985	1066705492.19
1957	-50472549.12	1986	944658321.58
1958	-40800403.45	1987	859754033.29
1959	-166927580.44	1988	772813060.50
1960	-387011612.14	1989	656103419.09
1961	-63327571.10	1990	577053655.23
1962	-643034666.84	1991	487927374.37
1963	-78807486.62	1992	422430216.92
1964	-184239430.10	1993	344506328.87
1965	-166036857.29	1994	269962955.15
1966	-306350025.39	1995	209117917.18
1967	-582406047.67	1996	176545270.27
1968	-744587992.16	1997	131694261.18
1969	12766674.66	1998	106867129.26
1970	251155973.70	1999	51827545.38
1971	575751859.16	2000	29728046.05
1972	689628117.68	2001	32274688.68
1973	791194829.10	2002	-3240758.30
1974	1228328008.27	2003	-18457768.71
1975	1006614898.50	2004	2008540.59
1976	1027175620.37	2005	-19275857.16
1977	1379711028.06	2006	-21150429.48
1978	1379224804.73	2007	-234928513.13
1979	1521230305.21	2008	-8895620.82
1980	1418293915.39	2009	-30578578.25
1981	1456533877.90	2010	-135956877.30
1982	1407667598.06		

Undiscounted Sum of NCF = $19,529,407,918.42

Undiscounted Sum of 1954-1978 NCF = $4,586,332,474.34

Cumulative Gross Production Value = $45,756,977,166.25

Cumulative Gross 1954-1978 Production Value = $17,909,084,704.00

Internal Rate of Return = 11.43

Total Acreage = 5,261,724

Number of Leases in Aggregate = 1223

Total Liquid = 3,426,720,503 barrels

Total Gas = 29,139,040,288 thousand cubic feet

Note: The negative cash flows for years after 2001 reflect net abandonment costs which are incurred after a decision to abandon a lease is made independent of these costs.

TABLE 37. IRR FOR SUB-CATEGORIES OF LEASES WITH BONUS COST DELETED FROM CASH FLOW

Lease Category	IRR (%)
Aggregate	19.10
Big 8*	18.80
Big 9-20	20.79
Non-Big-20	17.68
Solo	17.01
Joint	23.48
Wildcat	17.38
Drainage	31.71
1 Bidder	17.54
2 Bidder	18.48
3/4 Bidder	21.51
5/More Bidder	18.79
Bonus ≤ $250,000	13.55
" ≤ $1,000,000[1]	15.49
" ≤ $3,250,000[2]	19.52
" > $3,250,000	22.54

*Attributed shares for firm categories.

[1]Not including leases in previous bonus category.

[2]Not including leases in previous bonus categories.

TABLE 38.

BIG-8 LEASES[1]

	Number	IRR (%)	Gas/Oil Ratio (BTU's)	Average Bonus ($M) per Lease	Average Gross Value of Production ($M) Through 1978	2010	Average Net Cash Flow ($M) Through 1978	2010
Big 8 Leases	725.10	10.91	1.0	2,310	14,911	35,281	3,421	13,794
Solo	550	10.51	.74	2,137	14,666	33,508	3,042	12,261
Joint	175.10	11.93	2.23	2,852	15,678	40,850	4,612	18,608
Wildcat	632.66	9.71	.98	2,059	12,482	29,899	2,205	11,098
Drainage	92.44	16.07	1.07	4,026	31,534	72,116	11,742	32,245
1 Bidder	248.38	13.60	1.07	489	7,691	17,768	2,529	7,240
2 Bidder	128.46	10.68	1.45	1,006	8,974	21,447	1,871	8,579
3/4 Bidder	156.67	13.43	.92	2,174	20,504	43,270	6,326	16,997
5/More Bidder	191.59	9.02	.92	5,656	23,678	60,728	3,241	23,168
Bonus ≤ $250,000	210.49	12.59	.96	126	4,639	13,112	1,443	5,842
Bonus ≤$1,000,000	204.61	11.34	.76	506	9,379	22,404	2,260	8,496
Bonus ≤$3,250,000	179.03	11.05	1.25	1,817	16,671	36,539	4,302	14,397
Bonus >$3,250,000	130.97	10.29	.97	9,310	37,655	89,309	7,211	34,025

[1] Attributed shares.

TABLE 39.

BIG 9-20 LEASES[1]

	Number	IRR (%)	Gas/Oil Ratio (BTU's)	Average Bonus ($M) per Lease	Average Gross Value of Production ($M) Through 1978	Average Gross Value of Production ($M) Through 2010	Average Net Cash Flow ($M) Through 1978	Average Net Cash Flow ($M) Through 2010
All Big 9-20 Leases	298.57	12.21	2.69	2,354	14,762	41,228	4,706	20,223
Solo	165.00	10.85	4.96	1,682	10,479	29,689	2,826	14,293
Joint	133.57	13.35	1.90	3,184	20,052	55,482	7,029	27,547
Wildcat	261.34	11.76	3.14	1,958	13,252	37,284	4,146	18,172
Drainage	37.23	15.02	1.43	5,133	25,364	68,912	8,635	34,617
1 Bidder	92.24	14.50	2.91	568	6,979	19,604	2,611	10,088
2 Bidder	71.04	16.01	5.28	981	7,907	22,025	3,368	11,997
3/4 Bidder	51.45	13.34	1.40	2,685	18,916	56,489	5,853	27,690
5/More Bidder	83.84	10.68	2.95	5,280	26,584	71,924	7,441	33,760
Bonus ≤ $250,000	79.17	15.32	3.76	133	4,400	12,906	1,935	7,393
Bonus ≤$1,000,000	91.41	12.05	4.09	573	5,068	13,128	1,252	5,390
Bonus ≤$3,250,000	65.34	14.63	2.58	1,993	18,515	56,671	6,551	28,741
Bonus >$3,250,000	62.65	10.91	2.40	8,136	38,086	101,910	11,325	49,193

[1] Attributed shares.

TABLE 40.

NON-BIG 20 LEASES[1]

	Number	IRR (%)	Gas/Oil Ratio (BTU's)	Average Bonus ($M) per Lease	Average Gross Value of Production ($M) Through 1978	Average Gross Value of Production ($M) Through 2010	Average Net Cash Flow ($M) Through 1978	Average Net Cash Flow ($M) Through 2010
All Non-Big 20	199.33	11.90	1.50	1,743	13,494	39,458	3,514	17,507
Solo	146.00	9.52	3.95	946	7,806	23,499	1,323	9,821
Joint	53.33	15.16	.68	3,925	29,067	83,151	9,515	38,547
Wildcat	185.00	11.34	1.58	1,458	12,519	36,115	2,978	15,128
Drainage	14.33	16.87	1.41	5,431	26,092	82,617	10,444	48,215
1 Bidder	70.38	10.80	4.61	272	4,715	14,506	971	6,869
2 Bidder	45.50	14.23	7.04	772	10,969	35,551	3,563	16,871
3/4 Bidder	45.88	9.82	.71	2,970	14,700	44,863	1,415	16,337
5/More Bidder	37.57	12.52	.80	4,177	31,527	84,334	10,784	39,633
Bonus ≤ $250,000	64.34	5.80	3.23	119	1,932	8,021	-995	2,443
Bonus ≤$1,000,000	70.98	13.40	7.10	518	9,835	29,993	3,355	14,015
Bonus ≤$3,250,000	40.63	13.66	.83	1,936	26,022	68,988	8,760	29,727
Bonus >$3,250,000	23.38	10.70	.68	9,600	34,651	103,391	7,293	48,324

[1] Attributed shares

TABLE 41.

WILDCAT LEASES[1]

	Number	IRR (%)	Gas/Oil Ratio (BTU's)	Average Bonus ($M) per Lease	Average Gross Value of Production ($M) through 1978	Average Gross Value of Production ($M) through 2010	Average Net Cash Flow ($M) through 1978	Average Net Cash Flow ($M) through 2010
All Wildcat Leases	1079	10.57	1.45	1,932	12,675	32,754	2,808	13,502
Big 8	632.6	9.71	.98	2,059	12,482	29,899	2,205	11,098
Big 9-20	261.3	11.76	3.14	1,958	13,252	37,284	4,146	18,172
Non-Big 20	185.0	11.34	1.58	1,458	12,519	36,115	2,978	15,128
Solo	766	9.60	1.31	1,621	11,010	27,374	1,923	10,481
Joint	313	12.23	1.71	2,692	16,748	45,918	4,974	20,897
1 Bidder	362	12.63	1.28	325	6,371	16,168	2,001	7,175
2 Bidder	213	12.79	3.42	738	8,539	23,830	2,450	11,127
3/4 Bidder	209	12.32	1.08	1,464	14,544	35,808	3,995	14,703
5/More Bidder	295	8.90	1.33	5,097	22,072	57,385	3,215	22,131
Bonus ≤ $250,000	337	12.23	1.56	126	4,294	12,739	1,208	5,907
Bonus ≤$1,000,000	339	12.10	1.56	531	8,876	22,566	2,432	9,227
Bonus ≤$3,250,000	236	11.79	1.28	1,867	18,603	45,847	5,166	19,358
Bonus >$3,250,000	167	8.59	1.52	8,510	28,920	75,319	3,466	29,233

[1] Attributed shares for firm categories.

TABLE 42.

DRAINAGE LEASES[1]

	Number	IRR (%)	Gas/Oil Ratio (BTU's)	Average Bonus ($M) per Lease	Average Gross Value of Production ($M) through 1978	2010	Average Net Cash Flow ($M) through 1978	2010
All Drainage Leases	144	15.90	1.14	4,452	29,397	72,333	10,809	34,447
Big 8	92.5	16.07	1.07	4,026	31,534	72,116	11,742	32,245
Big 9-20	37.2	15.02	1.43	5,133	25,364	68,912	8,635	34,617
Non-Big 20	14.3	16.87	1.06	5,431	26,094	82,617	10,444	48,215
Solo	95	15.09	.95	3,682	26,334	60,951	9,047	26,397
Joint	49	17.07	1.45	5,945	35,335	94,400	14,227	50,056
1 Bidder	49	18.37	3.13	1,539	11,828	28,362	4,343	12,549
2 Bidder	32	12.52	1.03	2,402	12,337	26,924	3,748	10,997
3/4 Bidder	45	13.70	.81	6,869	40,450	94,662	11,607	39,204
5/More Bidder	18	19.49	1.06	9,983	79,921	216,938	38,974	123,859
Bonus ≤ $250,000	17	Neg.	.28	142	133	278	-839	-1,081
Bonus ≤$1,000,000	28	8.32	15.47	449	2,552	9,397	-342	3,494
Bonus ≤$3,250,000	49	17.15	2.03	1,911	17,577	45,462	6,835	22,342
Bonus >$3,250,000	50	16.04	.88	10,649	65,964	158,409	24,910	75,724

[1] Attributed shares for firm categories

TABLE 43.

SOLO BIDDER LEASES

	Number	IRR (%)	Gas/Oil Ratio (BTU's)	Average Bonus ($M) per Lease	Average Gross Value of Production ($M) Through 1978		Average Net Cash Flow ($M) Through 1978	
					1978	2010	1978	2010
All Solo Bidder Leases	861	10.43	1.22	1,848	12,701	31,079	2,709	12,237
Non-Big 20	146	9.52	3.95	946	7,806	23,499	1,323	9,821
Big 9-20	165	10.85	4.96	1,682	10,479	29,689	2,826	14,293
Big 8	550	10.51	.74	2,137	14,666	33,508	3,042	12,261
Wildcat	766	9.60	1.31	1,621	11,010	27,374	1,923	10,481
Drainage	95	15.09	.95	3,682	26,334	60,951	9,047	26,397
1 Bidder	312	12.90	1.17	400	6,622	16,919	2,006	7,377
2 Bidder	182	11.76	2.24	764	8,273	22,932	1,887	10,060
3/4 Bidder	168	10.02	.80	2,142	15,486	32,823	2,990	10,852
5/More Bidder	199	9.34	1.26	4,862	23,929	59,258	4,325	23,016
Bonus ≤ $250,000	265	10.87	1.66	127	3,375	10,461	676	4,678
Bonus ≤$1,000,000	283	12.29	1.50	524	8,822	22,699	2,417	9,598
Bonus ≤$3,250,000	186	10.76	1.38	1,792	16,492	37,923	3,938	14,888
Bonus >$3,250,000	127	9.16	.91	8,471	35,249	82,750	5,801	30,008

TABLE 44.

JOINT BIDDER LEASES[1]

	Number	IRR (%)	Gas/Oil Ratio (BTU's)	Average Bonus ($M) per Lease	Average Gross Value of Production ($M) Through 1978	Average Gross Value of Production ($M) Through 2010	Average Net Cash Flow ($M) Through 1978	Average Net Cash Flow ($M) Through 2010
All Joint Bidder Leases	362	13.07	1.64	3,133	19,264	52,481	6,226	24,844
Non-Big 20	53.33	15.16	.68	3,925	29,067	83,151	9,515	38,547
Big 9-20	133.57	13.35	1.9	3,184	20,052	55,482	7,029	27,547
Big 8	175.10	11.93	2.23	2,852	15,679	40,850	4,612	18,608
Wildcat	313	12.23	1.71	2,692	16,748	45,918	4,974	20,897
Drainage	49	17.07	1.45	5,945	35,335	94,400	14,227	50,056
1 Bidder	99	14.77	3.17	687	8,279	19,835	3,146	9,196
2 Bidder	63	15.34	4.60	1,507	11,238	27,996	4,736	14,143
3/4 Bidder	86	16.91	1.22	2,969	26,259	72,437	9,941	35,047
5/More Bidder	114	10.95	1.32	6,278	27,963	79,307	6,923	36,649
Bonus ≤ $250,000	89	15.05	1.35	124	6,233	17,141	2,401	8,230
Bonus ≤$1,000,000	84	10.60	2.62	527	6,948	17,729	1,559	6,068
Bonus ≤$3,250,000	99	15.21	1.38	2,030	22,061	60,543	8,299	29,234
Bonus >$3,250,000	90	12.18	1.75	9,753	40,570	110,994	12,085	53,967

[1] Attributed shares for firm categories.

TABLE 45.

ONE BIDDER LEASES[1]

	Number	IRR (%)	Gas/Oil Ratio (BTU's)	Average Bonus ($M) per Lease	Average Gross Value of Production ($M) through 1978	Average Gross Value of Production ($M) through 2010	Average Net Cash Flow ($M) through 1978	Average Net Cash Flow ($M) through 2010
All One Bidder Leases	411	13.37	1.56	470	7,010	17,622	2,281	7,815
Big 8	248.4	13.60	1.07	489	7,691	17,768	2,529	7,240
Big 9-20	92.2	14.60	2.91	568	6,979	19,604	2,611	10,088
Non-Big 20	70.4	10.80	4.61	272	4,715	14,506	971	6,869
Wildcat	362	12.63	1.28	325	6,371	16,168	2,001	7,175
Drainage	49	18.37	3.13	1,539	11,828	28,362	4,343	12,549
Solo	312	12.90	1.17	400	6,622	16,919	2,006	7,377
Joint	99	14.77	3.17	687	8,279	19,835	3,146	9,196
Bonus ≤ $250,000	253	12.20	1.41	116	3,994	10,826	1,203	4,910
Bonus ≤$1,000,000	113	13.24	1.43	460	7,611	19,459	2,443	8,882
Bonus ≤$3,250,000	37	13.80	1.57	1,619	18,352	44,890	5,416	18,113
Bonus >$3,250,000	8	19.32	2.50	6,461	42,022	80,450	19,552	36,999

[1] Attributed shares for firm categories.

TABLE 46.

TWO BIDDER LEASES[1]

	Number	IRR (%)	Gas/Oil Ratio (BTU's)	Average Bonus ($M) per Lease	Average Gross Value of Production ($M) through 1978	Average Gross Value of Production ($M) through 2010	Average Net Cash Flow ($M) through 1978	Average Net Cash Flow ($M) through 2010
All Two Bidder Leases	245	12.76	2.80	955	9,035	24,234	2,619	11,110
Big 8	128.5	10.68	1.45	1,006	8,974	21,447	1,871	8,579
Big 9-20	71.0	16.01	5.28	981	7,907	22,025	3,368	11,997
Non-Big 20	45.5	14.23	7.04	772	10,969	35,551	3,563	16,871
Wildcat	213	12.79	3.42	738	8,539	23,830	2,450	11,127
Drainage	32	12.52	1.03	2,402	12,337	26,924	3,748	10,997
Solo	182	11.76	2.24	764	8,273	22,932	1,887	10,060
Joint	63	15.34	4.60	1,507	11,238	27,996	4,736	14,143
Bonus ≤ $250,000	71	10.49	3.10	144	2,722	12,482	76	6,143
Bonus ≤$1,000,000	115	11.29	3.20	527	6,047	17,925	1,415	7,530
Bonus ≤$3,250,000	41	16.07	2.53	1,696	22,243	53,675	8,550	26,932
Bonus >$3,250,000	18	11.79	2.68	5,202	22,943	43,835	6,842	17,533

[1] Attributed shares for firm categories.

TABLE 47.

THREE-FOUR BIDDER LEASES[1]

	Number	IRR (%)	Gas/Oil Ratio (BTU's)	Average Bonus ($M) per Lease	Average Gross Value of Production ($M) through 1978	Average Gross Value of Production ($M) through 2010	Average Net Cash Flow ($M) through 1978	Average Net Cash Flow ($M) through 2010
All Three-Four Bidder Leases	254	12.76	.97	2,421	19,134	46,235	5,343	19,044
Big 8	156.7	13.43	.92	2,174	20,504	43,270	6,326	16,997
Big 9-20	51.4	13.34	1.40	2,685	18,916	56,489	5,853	27,690
Non-Big 20	45.9	9.82	.71	2,970	14,700	44,863	1,415	16,337
Wildcat	209	12.32	1.08	1,464	14,544	35,808	3,995	14,703
Drainage	45	13.70	.81	6,869	40,450	94,662	11,607	39,204
Solo	168	10.02	.80	2,142	15,486	32,823	2,990	10,852
Joint	86	16.91	1.22	2,969	26,259	72,437	9,941	35,047
Bonus ≤ $250,000	25	15.93	1.15	162	9,812	26,898	3,828	12,258
Bonus ≤$1,000,000	89	10.02	1.34	549	8,712	21,492	1,597	7,567
Bonus ≤$3,250,000	98	13.32	1.01	1,752	16,426	44,118	4,695	19,902
Bonus >$3,250,000	42	13.20	.83	9,297	53,083	115,119	15,697	45,398

[1] Attributed shares for firm categories.

TABLE 48.

FIVE AND MORE BIDDER LEASES[1]

	Number	IRR (%)	Gas/Oil Ratio (BTU's)	Average Bonus ($M) per Lease	Average Gross Value of Production ($M) through 1978	Average Gross Value of Production ($M) through 2010	Average Net Cash Flow ($M) through 1978	Average Net Cash Flow ($M) through 2010
All Five and More Bidder Leases	313	10.00	1.29	5,378	25,398	66,560	5,272	27,982
Big 8	191.6	9.02	.92	5,656	23,678	60,728	3,241	23,168
Big 9-20	83.8	10.68	2.95	5,280	26,584	71,924	7,441	33,760
Non-Big 20	37.6	12.52	.80	4,177	31,527	84,334	10,784	39,633
Wildcat	295	8.90	1.33	5,097	22,072	57,385	3,215	22,131
Drainage	18	19.49	1.06	9,983	79,921	216,938	38,974	123,859
Solo	199	9.34	1.26	4,862	23,929	59,258	4,325	23,016
Joint	114	10.95	1.32	6,278	27,963	79,307	6,923	36,649
Bonus ≤ $250,000	5	Neg.	6.60	204	22	22	-2,549	-2,549
Bonus ≤$1,000,000	50	13.60	1.28	626	14,990	34,798	4,683	13,655
Bonus ≤$3,250,000	109	10.41	1.25	2,139	18,815	44,609	4,983	17,784
Bonus >$3,250,000	149	9.59	1.30	9,515	34,558	95,511	5,943	41,273

[1] Attributed shares for firm categories.

TABLE 49.

LEASES WITH BONUS ≤ $250,000[1]

	Number	IRR (%)	Gas/Oil Ratio (BTU's)	Average Bonus ($M) per Lease	Average Gross Value of Production ($M) through 1978	Average Gross Value of Production ($M) through 2010	Average Net Cash Flow ($M) through 1978	Average Net Cash Flow ($M) through 2010
All Leases with Bonus ≤ $250,000	354	12.09	1.55	126	4,093	12,141	1,100	5,571
Big 8	210.5	12.59	.96	126	4,640	13,112	1,443	5,842
Big 9-20	79.2	15.32	3.76	133	4,400	12,906	1,935	7,393
Non-Big 20	64.3	5.80	3.23	119	1,932	8,021	-995	2,443
Wildcat	337	12.23	1.56	126	4,294	12,740	1,208	5,907
Drainage	17	Neg.	.28	142	133	278	-839	-1,081
Solo	265	10.87	1.66	127	3,375	10,461	676	4,678
Joint	89	15.05	1.35	124	6,233	17,141	2,401	8,231
1 Bidder	253	12.20	1.41	116	3,994	10,826	1,203	4,910
2 Bidder	71	10.49	3.10	144	2,722	12,482	76	6,143
3/4 Bidder	25	15.93	1.15	162	9,812	26,898	3,828	12,258
5/More Bidder	5	Neg.	6.60	204	22	22	-2,549	-2,549

[1] Attributed shares for firm categories.

TABLE 50.

LEASES WITH $250,000 ≥ BONUS ≤ $1,000,000[1]

	Number	IRR (%)	Gas/Oil Ratio (BTU's)	Average Bonus ($M) per Lease	Average Gross Value of Production ($M) through 1978	Average Gross Value of Production ($M) through 2010	Average Net Cash Flow ($M) through 1978	Average Net Cash Flow ($M) through 2010
All Leases with > $250,000 Bonus ≤ $1,000,000	367	11.96	1.65	525	8,393	21,561	2,221	8,790
Big 8	204.6	11.34	.76	506	9,379	22,404	2,260	8,496
Big 9-20	91.4	12.05	4.09	573	5,068	13,128	1,252	5,390
Non-Big 20	71.0	13.40	7.10	518	9,835	29,993	3,355	14,015
Wildcat	339	12.10	1.56	531	8,876	22,566	2,432	9,227
Drainage	28	8.32	15.47	449	2,552	9,397	-342	3,494
Solo	283	12.29	1.50	524	8,822	22,699	2,417	9,598
Joint	84	10.60	2.62	527	6,948	17,729	1,559	6,068
1 Bidder	113	13.24	1.43	460	7,611	19,459	2,443	8,882
2 Bidder	115	11.29	3.20	527	6,047	17,925	1,415	7,530
3/4 Bidder	89	10.02	1.34	549	8,712	21,492	1,597	7,567
5/More Bidder	50	13.60	1.3	626	14,990	34,798	4,683	13,655

[1] Attributed shares for firm categories.

TABLE 51.

LEASES WITH $1,000,000 < BONUS ≤ $3,250,000[1]

	Number	IRR (%)	Gas/Oil Ratio (BTU's)	Average Bonus ($M) per Lease	Average Gross Value of Production ($M) through 1978	2010	Average Net Cash Flow ($M) through 1978	2010
All Leases with $1,000,000 < Bonus ≤ $3,250,000	285	12.41	1.38	1,875	18,427	45,781	5,453	19,871
Big 8	179.0	11.05	1.25	1,817	16,671	36,539	4,302	14,397
Big 9-20	65.3	14.63	2.59	1,993	18,515	56,671	6,551	28,741
Non-Big 20	40.6	13.66	.83	1,936	26,022	68,988	8,760	29,727
Wildcat	236	11.79	1.28	1,870	18,603	45,847	5,166	19,358
Drainage	49	17.15	2.03	1,911	17,577	45,462	6,835	22,342
Solo	186	10.76	1.38	1,792	16,492	37,923	3,938	14,888
Joint	99	15.21	1.38	2,030	22,061	60,543	8,299	29,234
1 Bidder	37	13.80	1.57	1,619	18,352	44,890	5,416	18,113
2 Bidder	41	16.07	2.53	1,696	22,243	53,675	8,550	26,932
3/4 Bidder	98	13.32	1.01	1,752	16,426	44,118	4,695	19,902
5/More Bidder	109	10.41	1.25	2,139	18,815	44,609	4,983	17,784

[1] Attributed shares for firm categories.

TABLE 52.

LEASES WITH BONUS > $3,250,000[1]

	Number	IRR (%)	Gas/Oil Ratio (BTU's)	Average Bonus ($M) per Lease	Average Gross Value of Production ($M) through 1978	Average Gross Value of Production ($M) through 2010	Average Net Cash Flow ($M) through 1978	Average Net Cash Flow ($M) through 2010
All Leases with Bonus > $3,250,000	217	10.55	1.25	9,002	37,456	94,464	8,407	39,945
Big 8	131.0	10.29	.97	9,310	37,655	89,309	7,211	34,025
Big 9-20	62.6	10.91	2.40	8,136	38,086	101,910	11,325	49,193
Non-Big 20	23.4	10.70	.68	9,600	34,651	103,391	7,293	48,324
Wildcat	167	8.59	1.52	8,510	28,920	75,319	3,466	29,233
Drainage	50	16.04	.88	10,649	65,964	158,409	24,910	75,724
Solo	127	9.16	.91	8,471	35,249	82,750	5,801	30,008
Joint	90	12.18	1.75	9,753	40,570	110,994	12,085	53,967
1 Bidder	8	19.32	2.50	6,461	42,022	80,450	19,552	36,999
2 Bidder	18	11.79	2.68	5,202	22,943	43,835	6,842	17,533
3/4 Bidder	42	13.20	.83	9,297	53,083	115,119	15,697	45,398
5/More Bidder	149	9.59	1.30	9,515	34,558	95,511	5,943	41,273

[1] Attributed shares for firm categories.

TABLE 53.

DISTRIBUTION OF LEASES BY FIRM SIZE AND PROFITABILITY

	All Firms				Big 8 Firms[1]				Big 9-20 Firms[1]				Non-Big 20 Firms[1]			
	IRR (%)	No.	Average Bonus ($M)	Gas/ Oil Ratio (BTU's)	IRR (%)	No.	Average Bonus ($M)	Gas/ Oil Ratio (BTU's)	IRR (%)	No.	Average Bonus ($M)	Gas/ Oil Ratio (BTU's)	IRR (%)	No.	Av. Bonus ($M)	Gas/ Oil Ratio (BTU's)
All Leases	11.43	1223	2,228	1.375	10.91	725.1	2,310	1.0	12.21	298.57	2,354	2.69	11.90	199.33	1,743	1.5
Productive and Profitable Leases[a]	19.40	283	3,540	1.35	19.30	160.31	3,405	.96	19.54	74.50	4,041	2.67	19.51	48.19	3,215	1.45
Productive but Unprofitable Leases	*	183	2,967	1.81	*	112.51	3,397	1.53	*	34.61	3,025	3.38	*	35.88	1,561	3.26
Dry Leases	*	757	1,559	N/A	*	452.28	1,651	N/A	*	189.46	1,568	N/A	*	115.26	1,185	N/A

[1] Attributed shares for firm categories.

[a] A profitable lease is one with IRR > 0.0

*Negative.

TABLE 54.

PERCENT OF LEASES IN PROFITABILITY CATEGORIES

	% of All Leases	Big 8 Leases[1] % of All Leases In Row Category	Big 9-20 Leases[1] % of All Leases In Row Category	Non-Big 20 Leases[1] % of All Leases In Row Category
All Leases	100.	59.3[3]	24.41	16.3
Productive And Profitable[2]	23.14	56.65	26.33	17.03
Productive But Unprofitable	14.96	61.48	18.91	19.61
Dry Leases	61.9	59.75	25.03	15.23

[1] Attributed shares for firm subcategories.

[2] A profitable lease is one with IRR > 0.0

[3] The entries in the first row of the firm categories is the expected entries in the column below under the hypotheses that firm category is irrelevant for profitability category. For example, the Big 8 firms have 59.3% of all leases. Under the hypotheses above the expected entry for Big 8 productive and profitable bases is 59.3%. The actual entry is 56.65%.

Table 55. IRR FOR PRODUCTIVE OIL AND GAS LEASES WITH PROPORTIONATE ALLOCATION OF DRY LEASE COSTS*

	Lease Type	Number	IRR(%)	Gas/Oil Ratio (BTU's)
Aggregate	Oil	166	13.52	.32
	Gas	300	9.43	6.39
Non-Big 20	Oil	19.80	13.23	.34
	Gas	64.27	10.77	4.40
Big 9-20	Oil	27.16	13.48	.49
	Gas	81.95	11.48	10.35
Big 8	Oil	119.04	13.59	.28
	Gas	153.78	7.57	5.57
Solo	Oil	120	12.71	.29
	Gas	192	8.29	6.71
Joint	Oil	46	14.96	.39
	Gas	108	11.31	6.02
Wildcat	Oil	134	12.52	.30
	Gas	246	8.93	6.28
Drainage	Oil	32	17.49	.37
	Gas	54	13.13	6.97
One Bidder	Oil	28	18.63	.27
	Gas	77	10.29	7.39
Two Bidders	Oil	21	14.65	.38
	Gas	64	11.84	10.71
3-4 Bidders	Oil	52	14.90	.36
	Gas	68	9.91	5.01
5 or More Bidders	Oil	65	11.57	.30
	Gas	91	8.29	5.59
Bonus ≤ $250,000	Oil	17	18.26	.30
	Gas	49	8.10	9.14
Bonus $250,001 - 1,000,000	Oil	34	14.98	.24
	Gas	95	10.46	5.89
Bonus $1,000,001-3,250,000	Oil	58	13.49	.32
	Gas	87	11.35	5.67
Bonus > $3,250,000	Oil	57	12.40	.35
	Gas	69	8.21	6.93

*Costs of dry leases have been allocated as follows: The costs of dry leases in any category given in the first column can be computed from our data base. The dry lease costs for any category have been allocated to oil and gas leases in proportion to the number of oil and gas leases. An oil lease has been defined as one where the BTU content of past and future oil production exceeds that of gas production, and conversely for a gas lease.

TABLE 56.

INTERNAL RATE OF RETURN ON OIL AND GAS LEASES

	OIL			GAS		
	Number	IRR (Percent)	Average Bonus 000 (Dollars)	Number	IRR (Percent)	Average Bonus 000 (Dollars)
Productive (including productive but unprofitable) Leases						
All Leases	166	16.52	3,504	300	13.32	2,608
Big 8 Firms	119.04	16.96	3,663	153.79	11.34	3,200
Big 9-20 Firms	27.16	15.84	6,716	81.95	15.55	2,725
All Other Firms	19.80	14.84	7,264	64.27	15.23	1,044
Dry Leases Allocated Proportionately to Productive Leases*						
All Leases	166	13.53	7,125	300	9.43	5,141
Big 8 Firms	119.04	13.59	4,384	153.79	7.57	4,130
Big 9-20 Firms	27.16	13.48	7,107	81.95	11.48	3,903
All Other Firms	19.80	13.23	7,543	64.27	10.77	1,950

*The negative cash flow (including bonus costs) for dry leases has been included in the cash flows for productive leases in each category listed in proportion to the number of leases in each category.

TABLE 57.

IRR BY FIRM SIZE CATEGORIES

(ATTRIBUTED SHARES IN LEASES)

		IRR (%)	Number of Leases (Shares)	Gas/Oil Ratio (BTU's)	Average Bonus ($M)	Average Value of Production ($M) Through 1978	Average Value of Production ($M) Through 2010	Average Net Cash Flow per Lease ($M) Through 1978	Average Net Cash Flow per Lease ($M) Through 2010
Big 8	Productive[1]	14.48	272.82	1.0	3,402	39,630	93,770	13,323	40,891
	Dry	Neg.	452.28	-	1,651	-	-	-2,552	-2,552
	Oil	16.96	119.04	.28	3,663	62,299	141,440	23,688	62,593
	Gas	11.34	153.78	5.57	3,200	22,082	56,869	5,299	24,092
Big 9-20	Productive[1]	15.66	109.11	2.67	3,719	40,395	112,816	17,282	59,741
	Dry	Neg.	189.46	-	1,568	-	-	-2,536	-2,536
	Oil	15.84	27.16	.49	6,716	71,556	197,002	28,284	98,072
	Gas	15.55	81.95	10.35	2,725	30,067	84,915	13,635	47,037
Non-Big 20	Productive[1]	15.02	84.07	1.50	2,509	31,995	93,556	11,253	44,429
	Dry	Neg.	115.26	-	1,185	-	-	-2,130	-2,130
	Oil	14.84	19.80	.34	7,264	66,685	206,527	21,687	150,290
	Gas	15.23	64.27	4.40	1,044	21,308	58,752	8,039	27,219

[1] Includes both profitable and productive but unprofitable leases.

TABLE 58.

CHARACTERISTICS OF LEASES WITHIN
BONUS CATEGORIES

	Number of Leases in Category			
eases	Bonus $\leq$ \$250,000	Bonus $\leq$ \$1,000,000	Bonus $\leq$ \$3,250,000	Bonus > \$3,250,000
ll Leases	354	367	285	217
oint Leases	89	84	99	90
roductive Leases	66	129	145	126
roductive Joint Leases	17	36	49	52
il Leases	17	34	58	57
oint Oil Leases	4	8	15	19
as Leases	49	95	87	69
oint Gas Leases	13	28	34	33
ercentages				
oint Leases (%)	25.1	22.9	34.7	41.5
oint Productive eases (%)	25.8	27.9	33.8	41.3
oint Oil Leases (%)	23.5	23.5	25.9	33.3
oint Gas Leases (%)	26.5	29.5	39.1	47.8
roductive Leases (%)	18.6	35.1	50.9	58.1