FINAL REPORT
USGS Contract No. 14-08-0001-18678

Additional Studies of Competition and Performance in OCS Oil and Gas Sales, 1954-1975.

Principal Investigators:

Walter J. Mead
Philip E. Sorensen

Other Investigators:

Asbjorn Moseidjord
Dennis D. Muraoka

November 30, 1980

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

Preface

We wish to acknowledge the assistance provided by several individuals employed in the U.S. oil industry who helped us to obtain necessary data relating to taxation of oil and gas income from the OCS. We also thank the federal and state government officials who assisted us in developing our data base, particularly the staff of USGS Conservation Division in Reston and in Metarie. Most importantly, we acknowledge the constructive collaboration in this research of our Government Technical Officer, Holly Tomlinson.

It goes without saying that in 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.

354482

TABLE OF CONTENTS

EXECUTIVE SUMMARY

The objectives of this report are as follows:

(1) To estimate the after tax internal rate of return on OCS oil and gas leases issued in the Gulf of Mexico over the years 1954-1969.

(2) To estimate the share of economic rent implicit in 1954-1969 OCS leases which has been transferred to the federal government under the traditional bonus bid plus fixed royalty leasing system.

(3) To determine whether our previous findings regarding competitive performance in the OCS lease market in the period studied can be applied to the subsequent period of leasing, i.e., the years 1970-1975.

(4) To determine whether any significant learning effects may be observed in historical trends in IRR's over time within specific geological trends or areas.

(5) To determine whether the assignment of leases to the categories of wildcat and drainage in the LPR data base validly reflects the expected character of the leases at sale date.

Our results are as follows:

1. After Tax Internal Rate of Return

In our report to USGS dated March 1, 1980, we concluded that competition in the OCS lease market was effective. We based this conclusion on our finding that lessees of the first 1,223 leases issued in the Gulf of Mexico earned only 11.43 percent over the leasing period while in the same period manufacturing firms generally earned 19.81 percent, before taxes.

A potential criticism of our previous conclusion regarding the effectiveness of competition is that we have compared rates of return on a before tax basis. Given the favorable tax treatment accorded the oil industry prior to

1975, it is possible that rates of return earned by OCS lessees <u>after taxes</u> were higher than the competitive norm.

Our present analysis rejects this hypothesis. After accounting for all general and special tax legislation applicable to the U. S. oil industry in the period studied, we find that after tax rates of return earned by OCS lessees were significantly lower than after tax returns earned in U. S. manufacturing generally -- 9.02 percent as compared to 11.52 percent, respectively. The fact that OCS lessees earned <u>below normal</u> after tax returns in the leasing period 1954-1969 is evidence of the presence of effective competition in these lease markets.

We find that Big-8 firms earned the lowest after tax rate of return of all firm size categories: 8.55 percent. Intermediate size firms (Big-9-20) earned 9.63 percent after taxes. The highest after tax return was earned by the Non-Big-20 firms: 9.65 percent. These findings are not consistent with the hypothesis that the largest firms have market power in OCS lease sales.

Joint bidders earned a higher after tax rate of return on their OCS leases than solo bidders: 10.07 percent as compared to 8.37 percent. This is only partly explained by the fact that a higher proportion of joint bid leases are drainage leases than is the case for solo bid leases.

Drainage leases earned significantly higher after tax returns than wildcat leases: 12.98 percent as compared to 8.35 percent, respectively.

2. Federal Government Share of Economic Rent

The relatively low after tax IRR earned by OCS lessees is mirrored in the high degree to which the federal government has captured the implicit economic rent in the underlying resources. For after tax discount rates (reflecting the opportunity cost of capital) equivalent to or greater than the 9.02 percent earned by the OCS lessees, the federal government captures 100% or more of the implicit economic rent. At discount rates of 8 percent or more, the largest share of economic rent is captured by means of the bonus payment for all leases combined. For sub-categories of leases, only drainage leases and Non-Big-20 leases transfer their greatest percentage of economic rent by means of royalty payments. Because royalty payments are conditional upon production, these two sub-categories of leases have effectively been able to shift a larger share of risk to the federal government than other lease categories.

3. Application of Findings Regarding Competitive Performance to 1970-1975 OCS Lease Sales

We have carried out new regression analyses to determine (1) whether our earlier regression models based on 1954-1969 data can be used to predict 1970-1975 bidding behavior, and (2) whether our earlier models can be re-estimated based on 1970-1975 data to explain bidding results in the later time period.

We find that major political and economic changes occurring after 1969 have transformed the oil and gas lease market to such a degree that our high bid estimates based upon 1954-1969 data are not accurate for the 1970-1975 period. Our model significantly underpredicted actual average high bids, which increased from $2,228,831 in the 1954-1969 period to $10,864,084 in the 1970-1975 period.

By using the explanatory variables previously employed for the 1954-1969 leases, the regressions using 1970-1975 data produce parameter signs and significance levels that are the same or similar to those revealed in the earlier bidding record. Our model explains 65 percent of the observed variability in high bid during the first period, and 54 percent in the second period. Combining the data base for the years 1955-1975 and adding a dummy variable (POST6901) to test for significance of bidding differences between the two periods, gives clear confirmation of the significant change in the level of bids received in the later years.

In a refinement of our variables for firm size and joint-solo, we have confirmed our earlier findings regarding two hypotheses relating to competition. In neither period is there any evidence that Big-8 firms obtained leases at lower prices than Non-Big-8 firms. In fact, the converse is true for some combinations of the above variables. Furthermore, in neither period do we find any evidence that firms bidding jointly obtained leases at lower prices than firms bidding alone, and again the converse is true for some combinations.

To further explain the differences in bidding behavior in the two periods, we defined new regression models which are capable of testing for differences in the impact of each explanatory variable from one period to the next. We find that for all variables representing the interactions of firm size, type of lease (wildcat/drainage), and form of bidding (solo/joint) there was a significant increase in high bid levels in the later period. Thus the shift in levels of high bid was not confined to a limited subset of these interaction categories.

Our results show that the federal government received a net benefit (in higher bids) from a simultaneous decline in the impact of each bidder and an increase in the average number of bidders. Two other independent variables in our regression models showed significant changes from one period to the other. The impact of the size of a lease (acreage) on the high bid was much reduced in the later period. Similarly, the impact of share of past leases owned by the winning bidder was also significantly reduced, indicating that established bidders with large leaseholdings were no longer in an advantageous position in bidding for the 1970-1975 leases.

4. Internal Rates of Return by Geological Trend and Area

Our study of changes in internal rates of return over time for leases located in specific geological trends and areas offshore reveals no significant learning effects (systematic movements of IRR's to higher levels) in the case of wildcat leases. For drainage leases, a continuous rise in IRR is seen only in the miocene trend indicating that bidders may have benefited from learning effects there. This result may also reflect assymetric information possessed by bidders for drainage leases. In other geological trends, IRR's for drainage leases move upward in early years but then stabilize at a level near 15 percent (after taxes). Thus learning effects appear to be confined to drainage sales and, even there, are not observed continuously over time for all geological trends.

5. Validity of Classification System for Wildcat and Drainage Leases

Our findings relating to after tax rates of return are that bidders for wildcat leases have consistently overestimated the potential quality of these leases while bidders for drainage leases have achieved after tax profitability levels in excess of those observed in U. S. manufacturing generally. Restudy of the wildcat/drainage classification system used by USGS shows that all wildcat leases were correctly classified in the USGS data base while twenty pre-1970 drainage leases were mis-classified. Reclassification of these twenty leases as wildcat leases does not significantly affect our results concerning before or after tax internal rates of return for the wildcat/drainage lease categories.

I. THE AFTER TAX INTERNAL RATE OF RETURN ON OCS OIL AND GAS LEASE INVESTMENTS

I.1. Comparison with Results of Earlier Research

The principal objective of our earlier research[1] was to estimate the internal rate of return earned by lessees on OCS leases issued in the Gulf of Mexico from 1954 through 1969. Our findings are summarized in the following passage:

> (T)he internal rate of return for all 1,223 leases is estimated at 11.43 percent _before taxes_. 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. Thus, the estimated IRR on OCS oil and gas leases is approximately 42 percent below normal competitive returns on capital.[2]

A potential criticism of this conclusion is its focus on _before tax_ returns. The theoretically correct comparison of rates of return would be on an _after tax_ basis, both for OCS producers and for comparable industries. Given the favorable tax treatment of income from oil and natural gas production in periods prior to the enactment of the windfall profits tax in 1980, the _before tax_ rate of return on OCS lease investments could be below that of industries in comparable risk categories while the _after tax_ rate of return for oil producers was higher. The present report serves as

---

[1] Walter J. Mead, Philip E. Sorensen, Russell O. Jones and Asbjorn Moseidjord, _Competition and Performance in OCS Oil and Gas Lease Sales and Development_, _1954-1969_, USGS Contract No. 14-0001-16552, March 1, 1980.

[2] _Ibid._, p.10.

a test of this hypothesis by estimating both _before tax_ and _after tax_ rates of return earned on 1954-1969 OCS leases, and then comparing these rates of return to those earned by U. S. manufacturing firms in the same time period.

I.2. Methodology for Estimating Taxes

Tax liabilities for each of the 1,223 leases included in our study are estimated in the following steps:

a) Taxes and special tax provisions applicable to income generated from OCS activity are identified.

b) Methods by which these taxes affect net income flows to the lessee are described. This description gives consideration to the fact that tax statutes have been periodically revised by Congress. In 1969 and 1975, for example, important changes were introduced affecting the treatment of percentage depletion allowances for oil and gas income.

c) A computational algorithm is developed to estimate the tax liability of each lease based on actual and predicted income and on actual and estimated cost data.

The following aspects of oil and gas taxation are identified as relevant for OCS production.

1) Corporate tax rates
2) Corporate income tax surcharges
3) Cost depletion
4) Percentage depletion
5) Expensing of intangible drilling costs
6) Depreciation of tangible drilling costs
7) Expensing of dry hole costs
8) Windfall profits tax

9) Investment tax credit
10) Capital gains treatment
11) Minimum tax
12) State taxes

A full description of these taxes and tax provisions and the computational algorithm used to estimate them is found in Appendix 1, "The Tax Treatment of Income from the OCS."

The tax liability of each lease in the OCS data base is estimated on an annual basis and then aggregated into an annual tax obligation for various groupings of leases. This tax liability is then subtracted from the aggregate net (before tax) cash flow by year, yielding an after tax internal rate of return. The results of this analysis are reported in Table 1.

I.3. Summary Results for Internal Rates of Return

Our results show the before tax internal rate of return for all 1,223 leases to be 11.34 percent[3] (see Table 1). Our estimate of the aggregate after tax internal rate of return is 9.02 percent. Thus the net effect of tax liability is to reduce the before tax IRR by 20 percent.

These before and after tax rates of return on OCS leases are low relative to rates of return on shareholder equity

---

[3] To maintain consistency with our earlier report, before tax rates of return are computed after the windfall profits tax. The before tax rate of return reported here varies slightly from that reported in our earlier study (11.43 percent). The difference reflects changes in the data and the windfall tax which have occurred since the completion of that report. A full explanation of these changes is found in Appendix 2, "Changes in Data and Algorithms for Computing Before Tax Internal Rates of Return."

Table 1. Internal Rate of Return-- 1,223 OCS Leases Issued 1954-1969

	Number of Leases	Internal Rate of Return Before Tax	Internal Rate of Return After Tax	Percentage Reduction in Before Tax IRR	Average Bonus Per Lease*	Average Gross Value of Production* Through 1979	Average Gross Value of Production* Through 2010
All Leases	1,223	11.34	9.02	20%	2,228	16,699	47,292
Big 8**	725	10.84	8.55	21%	2,310	16,718	45,076
Big 9-20**	299	12.23	9.63	21%	2,354	17,231	49,513
Non-Big-20**	199	11.68	9.65	17%	1,740	15,831	52,033
Solo	861	10.37	8.37	19%	1,848	14,581	40,516
Joint	362	12.99	10.07	22%	3,133	21,736	63,407
Wildcat	1,123	10.54	8.35	21%	2,006	14,604	41,805
Drainage	100	16.37	12.98	21%	4,729	40,219	108,905
1 Bidder	411	13.02	11.07	15%	470	7,982	21,430
2 Bidders	245	12.76	10.46	18%	955	10,634	31,738
3 or 4 Bidders	254	12.43	10.01	19%	2,422	21,408	56,429
5 or More Bidders	313	10.12	7.76	23%	5,378	29,071	86,011
Bonus 1	354	12.57	11.01	12%	126	4,997	18,049
Bonus 2	367	11.32	9.79	14%	525	9,661	26,510
Bonus 3	285	12.23	10.12	17%	1,875	20,807	54,937
Bonus 4	217	10.59	7.82	26%	9,003	42,296	120,103

* Average Bonus and Gross Value of Production are in Thousands of Dollars
** Attributed shares for each firm category

Bonus 1: Bonus < $250,000
Bonus 2: $250,000 < Bonus < $1,000,000
Bonus 3: $1,000,000 < Bonus < $3,250,000
Bonus 4: $3,250,000 < Bonus

for U.S. manufacturing industries over the years 1954-1978. The latter averaged 20.78 and 11.52 percent respectively.[4] Thus, despite the oil industry's preferential tax treatment over most of the period involved in our study, the after tax IRR for OCS lessees was approximately 22 percent <u>less than</u> the rate of return for all manufacturing firms.

I.4. Comparison of Large vs. Small Firms

There is concern among policymakers and the public at large that "big oil" companies may have an unfair advantage relative to smaller oil companies in competing for OCS leases. If this concern is valid, we would expect to find evidence showing that large firms earn higher rates of return than their smaller counterparts. To test this hypothesis, we have estimated the rate of return (both before and after tax) of OCS leases held by Big-8, Big 9-20 and Non-Big-20 firms. The ranking of firms is based on 1969 worldwide corporate sales.

Our findings do not support the hypothesis that big oil companies have a competitive advantage. In fact, we find that large firms earn <u>lower</u> rates than smaller firms involved in OCS leasing. On an after tax basis, the highest rate of return was earned by the Non-Big-20 firms (9.65

---

[4] Federal Trade Commission, Quarterly Financial Reports of Manufacturing Corporations. Washington D.C., U.S. Government Printing Office, 1954-1978. Rates of return are computed by the FTC on an accounting basis whereas our analysis is made on an economic basis; furthermore, the risk associated with OCS investments would appear to be greater than the average risk for all U. S. manufacturing. Thus the rate of return comparisons are only broadly valid.

percent), while the Big 9-20 firms fall into an intermediate position (earning 9.63 percent). The largest firms earned the lowest after tax rate of return: 8.55 percent. Differences in tax obligations based upon firm size are not alone responsible for this outcome, as can be seen in the fact that Big-8 firms also earned the lowest rate of return on a before tax basis.

I.5. Comparison of Solo and Joint Bidding

Our earlier report showed that joint bidders earn a higher rate of return before taxes than solo bidders. This was partly explained by the fact that joint bidders have won a larger share of the more profitable drainage leases.[5]

Similar results are obtained in our present analysis where solo bidders earned 10.37 percent before taxes and 8.37 percent after taxes, while joint bidders earned 12.99 percent and 10.07 percent, respectively, in these two categories.

I.6. Comparison of Wildcat and Drainage Leases

Perhaps the most surprising finding of our earlier report was that wildcat leases, despite their greater perceived risk, yielded much lower rates of return to lessees than drainage leases.[6] After careful restudy of this ques-

[5] Mead and Sorensen, pp. 164-165. Based upon our reclassification of leases (see section 1.6, below), 11.8% of joint bidder leases are drainage leases, while only 7.7% of solo leases are drainage leases.

[6] Mead and Sorensen, *op. cit.*, pp. 16-19.

tion and some reclassification of leases (as discussed below), we have concluded that this result cannot be refuted on empirical grounds. We find that wildcat leases yielded rates of return equal to 10.54 percent before taxes and 8.35 percent after taxes, while drainage leases yielded 16.37 percent and 12.98 percent, respectively. Thus the after tax yield on drainage leases was over 55 percent higher than that for wildcat leases.

How could such a result occur in a competitive lease market? Our explanation, in summary, is that bidders for wildcat leases consistently overestimated the potential quality of these leases. For whatever reason (perhaps fear of being left out of another Prudhoe Bay) bidders have shown a preference for the small probability of a large wildcat discovery over the higher probability of a smaller drainage discovery. Some further analysis of problems relating to information and expectations is provided in section I.7, below.

The higher rates of return earned on drainage leases in our study raised for us the question of whether the leases in our data base had been properly classified. Our investigation of this question showed this not to be a major problem.

Explicit classification of leases as wildcat or drainage first became relevant as a result of the tidelands dispute between the State of Louisiana and the federal government.[7]

---

[7] See Mead and Sorensen, op. cit., pp. 48-51.

Paragraph 13 of the Agreement of October 12, 1956, Between United States and Louisiana states that

> No new leases shall be granted by either party in that part of the disputed area lying in Zone No. 2, except that when the Secretary of the Interior and the State Mineral Board of Louisiana shall jointly determine new leases are necessary to prevent drainage of unleased lands, the Secretary of the Interior may grant such new leases . . .

In the period through 1969 the USGS followed the practice of labeling entire lease sales either wildcat or drainage sales. The first drainage sales included only Zone 2 tracts. In later drainage sales, tracts in Zone 3 were added. Eventually, in 1969, non-drainage tracts were included and offered in "drainage" sales. Since the LPR-series used in our study classifies any lease issued in a drainage sale as a drainage tract, an error in analysis will result if the distinction between wildcat and drainage is relevant. With the assistance of USGS officials in Reston and Metarie, we have been able to identify twenty leases which were incorrectly classified as drainage leases in the LPR data base.[8] It should be noted that misclassification of leases in the LPR data base for leases issued after 1969 is not a problem.

It is natural to ask whether any of the leases issued in wildcat sales should really have been classified as drainage leases. USGS officials who were actively engaged in the

---

[8] We are especially indebted to Gerald Crawford, USGS, Metarie for searching through the files and thus enabling us to make the final reclassification.

Gulf of Mexico leasing program in the 1960's conclude that this is not the case. Some leases designated as "wildcat" may eventually have drained previously discovered reservoirs, but the possibility of this occurring was not perceived by USGS officials (nor by bidders, in all likelihood) at the time of lease sale.

We have repeated parts of our earlier analysis with a corrected classification of twenty 1969 drainage leases (see Table 2). The leases which are reclassified received higher than average bonus payments, but were below average in productivity. Putting these leases into the wildcat category increases the reported difference in rates of return between wildcat and drainage leases, as compared to our previous study, and, at the same time, slightly reduces the distinction between wildcat and drainage tracts in our new regression models of high bids.[9]

I.7. The Effect of Geological Trend on IRR

---

[9] Beginning in 1970, USGS labelled most lease sales as "general", implying that leases are classified individually. These USGS classifications are made public prior to the sale. In the LPR data base for 1970-1975, leases are shown as either wildcat, drainage or development. For an analysis using data from both this period and the 1954-1969 period where lease types are relevant, we face a problem of how to condense these three lease categories into the two categories used in 1954-1969 sales. We have resolved this problem by classifying exploratory leases as wildcat leases. This decision was made on the basis of assurances from USGS officials that the definition of a drainage tract has not changed over time. Consistency in classification could, therefore, best be preserved by keeping the drainage category unchanged and combining all other leases into the wildcat category.

Table 2.

LEASES RECLASSIFIED FROM DRAINAGE TO WILDCAT

Sale Date	OCS Number	Tract Number	Area	Block
01-14-69	1879	LA 1999	W. Cameron	111
01-14-69	1881	LA 2006	Vermillion	112
01-14-69	1884	LA 2009	"	216
01-14-69	1885	LA 2011	S. Marsh Island	40
01-14-69	1891	LA 2021	Eugene Island	260
01-14-69	1893	LA 2023	"	265
01-14-69	1895	LA 2025	Ship Shoal	113
01-14-69	1896	LA 2927	"	193
01-14-69	1898	LA 2029	S. Timbalier	148
01-14-69	1900	LA 2031	Grand Isle	62
01-14-69	1904	LA 2036	Main Pass S. & E.	315
01-14-69	1903	LA 2034	Main Pass	95
12-16-69	1954	LA 2043	Vermillion	103
12-16-69	1956	LA 2049	Eugene Island	247
12-16-69	1959	LA 2052	"	258
12-16-69	1960	LA 2055	S. Timbalier	148
12-16-69	1961	LA 2056	"	149
12-16-69	1962	LA 2057	"	204
12-16-69	1965	LA 2060	Main Pass	143
12-16-69	1968	LA 2063	Main Pass S. & E.	291

Our earlier report demonstrated that the profitability of leases has varied widely over time and that lessees, in the aggregate, have earned a subnormal rate of return on their leases.[10] These results suggest that bidders were generally mistaken in their expectations about the true value of tracts because of poor information about the physical resources present or poor forecasts of future economic conditions.

In this section, we define certain areas and geological trends in the Gulf of Mexico and show how the internal rate of return varies over time in each geological trend and in each area. We wish to test the hypothesis that the variability of the IRR's tends to decrease over time and to converge towards a particular level. The justification for this hypothesis is that as bidders become more familiar with the geology of the area where a tract is located, there is a reduction in the amount of uncertainty about the physical resources present. Thus, expectations about the true value of the tract will reflect more closely the value which is ultimately going to be realized. We have too few observations to derive statistically significant results for this hypothesis; therefore, our approach will be to inspect visually the behavior of internal rates of return over time.

The geology of the Gulf of Mexico is composed of a set of geological trends of differing age. Roughly speaking,

---

[10] Mead and Sorensen, op. cit., p. 156.

each geological trend is a belt running parallel to shore.[11] From north to south these trends are miocene, pliocene, plio-pleistocene and pleistocene. The sand and reservoir conditions encountered in each geological trend are not homogenous throughout the trend, however, mainly because of the impact of the Mississippi River. For example, as the pliocene trend runs from the eastern part of the Gulf of Mexico towards the western part, one encounters large areas with no sedimentary deposits and hence no reservoirs.

In collaboration with USGS geologists, we have developed a two-way classification of the 1,223 tracts in our study according to both geological trend and area (see Table 3). The areas are listed from west to east while the geological trends are listed from north to south.

Table 3

AREA AND GEOLOGICAL TREND CLASSIFICATIONS

Area	Description	Geological Trend
AREA 1	South of Texas	Miocene Pliocene
AREA 2	Southwest of Louisiana	Miocene Pliocene Plio-Pleistocene Pleistocene
AREA 3	Southeast of Louisiana	Miocene Pliocene Pleistocene Cretaceous
Florida	West of Florida	No classification available

Tables 4 - 8 report before and after tax internal rates of return by sale date for the leases issued in each geological trend in each area.

Of the 1,223 leases, 188 (or 15.4 percent) were issued in four sales for the offshore Texas area (see Table 4). Almost all of these were located close to shore in the miocene trend. The lessees paid a total of more than $640 million for these leases, but earned a zero internal rate of return in aggregate both before and after taxes. There is no evidence of any learning effect in this area. Leases in Area 1 remained poor investments throughout the 1954-1969 leasing period.

The record for the southwest Louisiana area is shown in Tables 5 and 6. 767 (61.9 percent) of the leases in our study were issued for this area, most of which lies in the pliocene and pleistocene trends. For wildcat leases, there is no detectable tendency for the internal rate of return to stabilize at any level, either for the individual geological trends or for all leases in Area 2 (see Table 5). But when only drainage leases are considered, it appears that there is a tendency towards increasingly high internal rates of return in the miocene trend (see Table 6). This is an interesting finding since as many as 50 of the 100 drainage leases in our study are located in the miocene trend in Area 2. It can also be seen that the after tax rate of return in Area 2 for the drainage leases tended to stabilize at a level higher than 15 percent.

Table 4. Internal Rates of Return For Leases Issued in Area 1 (South of Texas)[1]

Sale Date	Geological Trend: Miocene — Internal Rate of Return (Percent) Before Tax	After Tax	Number of Leases	Pliocene — Internal Rate of Return (Percent) Before Tax	After Tax	Number of Leases	Total for All Leases in Area 1 — Internal Rate of Return (Percent) Before Tax	After Tax	Number of Leases
07-12-55	0	0	26				0	0	26
02-24-60	6	4	48				6	4	48
03-16-62	0	0	9				0	0	9
05-21-68	0	0	105	0	0	5	0	0	110
Total, All Sales	0	0	188	0	0	5	0	0	193

[1]All leases issued in this area in the period 1954-1969 were wildcat leases.

Table 5. Internal Rates of Return for Wildcat Leases Issued in Area 2 (Southwest of Louisiana)

	Geological Trend in Area 2												Totals for Area 2		
	Miocene			Pliocene			Pleistocene			Plio-Pleistocene					
	Internal Rate of Return (Percent)		Number of Leases	Internal Rate of Return (Percent)		Number of Leases	Internal Rate of Return (Percent)		Number of Leases	Internal Rate of Return (Percent)		Number of Leases	Internal Rate of Return (Percent)		Numbe of Lease
Sale Date	Before Tax	After Tax		Before Tax	After Tax		Before Tax	After Tax		Before Tax	After Tax		Before Tax	After Tax	
11-00-54[1]	3	2	38	8	7	61	4	2	9	0	0	1	7	6	109
07-12-55	8	6	52	10	8	41							9	7	93
08-11-59[2]	3	2	11										3	2	11
02-24-60	13	10	37	17	14	41				13	10	8	15	12	86
03-13-62	4	3	39	14	12	73	0	0	7	15	13	33	13	11	152
03-16-62	7	6	18	12	11	89	0	0	32	0	0	33	10	8	172
10-09-62[2]	18	15	3										18	15	3
04-28-64[2]	22	17	12										22	17	12
03-29-66[2]	20	16	10										20	16	10
10-18-66	0	0	14	0	0	1							0	0	15
06-13-67	0	0	28	25	20	22	0	0	12	0	0	5	15	11	67
11-19-68[2]	28	23	11										28	23	11
01-14-69[3]	0 (0)	0 (0)	3(2)	11 (8)	7 (4)	6(5)				20 (17)	15 12)	7(2)	13	9 (5)	16(
12-16-69[3]	29 (0)	23 (0)	2(1)	13 (7)	9 (5)	7(4)				0	0	1	15	11 (4)	10(
Total All Sales	11 (8)	.9 (6)	278(229)	12 (12)	11(11)	341(337)	0	0	60	10 (10)	8 (8)	88(83)	11(11)	9(.9)	767(3

[1]Sales held 10-13-54 and 11-09-54 combined.

[2]All leases in this sale were drainage leases.

[3]Combined wildcat and drainage sale. Numbers in parentheses in this row show internal rate of return for wildcat leases in this sale and the number of wildcat leases.

Table 6. Internal Rates of Return for Drainage Leases Issued in Area 2 (Southwest of Louisiana)

Sale Date	Geological Trend: Miocene IRR (Percent) Before Tax	Miocene IRR (Percent) After Tax	Miocene # of Leases	Pliocene IRR (Percent) Before Tax	Pliocene IRR (Percent) After Tax	Pliocene # of Leases	Plio-Pleistocene IRR (Percent) Before Tax	Plio-Pleistocene IRR (Percent) After Tax	Plio-Pleistocene # of Leases	Total for All Drainage Leases in Area 2 IRR (Percent) Before Tax	Total IRR (Percent) After Tax	Total # of Leases
08-11-59	3	2	11							3	2	11
10-09-62	18	15	3							18	15	3
04-28-64	22	17	12							22	17	12
03-29-66	20	16	10							20	16	10
11-19-68	28	23	11							28	23	11
01-14-69	0	0	1	21	17	1	22	16	5	20	15	7
12-16-69	37	29	1	20	16	3				24	19	4
Total All Sales	18	15	49	20	16	4	22	16	5	18	15	58

Internal rate of return data for Area 3 are shown in Tables 7 and 8. As in the other areas, there is no apparent tendency for the internal rate of return on wildcat leases to converge toward any specific level over time. This can be seen for both the individual geological trends and for the totals for this area (see Table 7). The record for drainage leases in this area is more ambiguous. In the miocene trend (disregarding the two leases issued in the last two sales) the internal rate of return tends to rise to increasingly high levels (see Table 8). But for all drainage leases in Area 3, rates of return (after tax) stabilize at the level of about 15 percent.

Table 7. Internal Rates of Return for Leases Issued in Area 3 (Southeast of Louisiana) and for All 1223 Leases

Sale Date	Geological Trend in Area 3[4]									Totals for Area 3			Totals for All 1223 Leases Issued 1954-1969		
	Miocene			Pliocene			Pleistocene								
	Internal Rate of Return (Percent)		Number of Leases	Internal Rate of Return (Percent)		Number of Leases	Internal Rate of Return (Percent)		Number of Leases	Internal Rate of Return (Percent)		Number of Leases	Internal Rate of Return (Percent)		Number of Leases
	Before Tax	After Tax		Before Tax	After Tax		Before Tax	After Tax		Before Tax	After Tax		Before Tax	After Tax	
11-00-54[2]													7	6	109
07-12-55	0	0	2							0	0	2	9	7	121
05-26-59													0	0	23[5]
08-11-59[2]	13	10	6	0	0	2				10	8	8	8	6	19
02-24-60	24	22	1	21	19	8	0	0	4	21	19	13	15	12	147
03-13-62	21	18	25	9	8	22	0	0	7	15	13	54	13	12	206
03-16-62	16	14	23	54	51	1				24	21	24	11	9	205
10-09-62[2]	23	18	3	1	0	3				13	10	6	14	10	9
04-28-64[2]	20	16	11							20	16	11	21	16	23
03-29-66[2]	24	19	6	0	0	1				23	18	7	22	17	17
10-18-66	12	9	5	19	14	4				17	13	9	12	9	24
06-13-67	14	10	35	6	5	43				9	6	91	11	8	158
05-21-68													0	0	110
11-19-68[2]	11	8	3	0	0	2				10	7	5	19	14	16
01-14-69[3]	0	0	1	22 0)	15 (0)	3(2)				12(0)	9 (0)	4(3)	13 (2)	9 (0)	20(1
12-16-69[3]	41	31	6							41(0)	31 (0)	6(2)	21 (5)	15 (4)	16(8
Total, All Sales	18 (18)	14(14)	127(94)	11 (12)	9(10)	89(80)	0	0	11	14(14)	11(11)	240(19	11 (11)	9(8)	1223 (1123

[1]Sales held 10-13-54 and 11-09-54 combined.

[2]All leases in this sale were drainage leases

[3]Combined wildcat and drainage sale. Numbers in parentheses in this row show internal rate of return for wildcat leases in this sale and the number of wildcat leases.

[4]13 leases issued 06-13-67 for the cretaceous trend not shown separately, but included in totals. These leases earned a zero internal rate of return both before and after tax.

[5]These 23 leases issued offshore Florida are not included in geological trends but in totals for all 1223 leases only.

Table 8. Internal Rates of Return for Drainage Leases Issued in Area 3 and for All Drainage Leases Issued 1954-1969

Sale Date	Geological Trend in Area 3						Total for Area 3			Total for All Drainage Leases		
	Miocene			Pliocene								
	IRR (Percent)		#	IRR (Percent)		#	IRR (Percent)		#	IRR (Percent)		#
	Before Tax	After Tax	of Leases	Before Tax	After Tax	of Leases	Before Tax	After Tax	of Leases	Before Tax	After Tax	of Leases
08-11-59	13	10	6	0	0	2	10	8	8	8	6	19
10-09-62	23	18	3	1	0	3	13	10	6	14	10	9
04-28-64	20	16	11				20	16	11	21	16	23
03-29-66	24	19	6	0	0	1	23	18	7	22	17	17
11-19-68	11	8	3	0	0	2	10	7	5	19	14	16
01-14-69				35	25	1	35	25	1	26	20	8
12-16-69	43	32	4				43	32	4	31	24	8
Total All Sales	18	14	33	5	3	9	15	12	42	16	13	100

Summarizing our investigation of geological and area trends, our internal rate of return results fail to support the hypothesis that any learning effect takes place for wildcat leases. This result is not so conclusive as to allow us to reject the hypothesis that knowledge of area and geological trend is helpful in estimating economic values of tracts offered for sale. It may be that even if resource uncertainty has been reduced, uncertainty about future economic conditions has increased, and the latter is not accounted for explicitly in our analysis.

For drainage leases, it appears that after tax rates of return in the geological trends where most leases have been issued, either tend to stabilize above the level of 15 percent or tend to increase beyond this level over time. Thus there is mixed evidence supporting the theory of a learning effect.

II. THE SHARE OF ECONOMIC RENT CAPTURED BY THE FEDERAL GOVERNMENT

II.1. Introduction

Economic rent is commonly defined in economics as any payment to a factor of production in excess of the minimum necessary to engage it in production. In the case of OCS lands owned by the federal government, the minimum supply price necessary to induce the federal government to lease production rights would be the costs of establishing and administering lease contracts. Assuming, for the sake of simplicity, that these costs are small enough to be ignored in the analysis, all payments to the federal government for use of OCS lands are forms of economic rent.

An ideal leasing system should transfer the full amount of economic rent implicit in OCS resources to the federal government. Whether such a complete transfer of economic rent occurs depends upon the conditions of competition in the market for OCS leases.

The principal means for capturing economic rent under the bidding system employed by the federal government over the years 1954-1969 are the bonus paid by the highest bidder and a royalty payment which has historically been fixed at 16 2/3 percent of gross production value. Of less importance is an annual rental payment, usually about \$3.00 per acre, which is paid as long as a tract under lease is not producing.

In the sections which follow, major factors affecting the capture of economic rent by the federal government are discussed and data are presented which demonstrate the importance of the different means used. In computing the amounts of economic rent captured by the federal government, the discounted cash flow technique is employed. This requires selection of an appropriate discount rate, in contrast to the internal rate of return analysis used in Part I, above.

II.2. Methodology

The process of bidding for OCS leases involves a complex analysis of estimated revenues and costs occurring with various probabilities over a long series of years. The ultimate choice of a bonus bid is conditional upon these estimates expressed in net present value terms. The latter expresses the difference between the present value of expected revenues and the present value of expected costs of labor and capital required to produce this revenue. These streams of expected revenues and costs are discounted by each bidding firm using a discount rate which reflects the opportunity cost of capital to the firm and the risk premium. While firms do not routinely disclose the discount rates used in computing bonus bids, it is reasonable to suppose that such rates are somewhat above the level of interest rates (prime borrowing rates) for oil companies in the period of the lease sales. Our judgement is that the discount rate used by bidders in the 1954-1969 period lay in the range of from 8 to 12 percent, after taxes.

II.3. Results of Analysis of Economic Rent Captured

Table 9 reports results of our analysis of the share of economic rent in OCS leases captured by the federal government, using various discount rates (or opportunity costs for capital invested). Each category of leases included in Table 9 is treated, for the purpose of this analysis, as comprising one continuous investment stream starting in 1954 and ending in 2010. The true or implicit economic rent for each year is computed as gross revenue minus taxes and all costs of exploration and production in that year, but without including bonus, royalty and rental payments among these costs.[12] The amount of economic rent paid to the federal government is the discounted sum of the separate streams of bonus, royalty and rental payments. The entries shown in Table 9 were computed by discounting after tax rent (or true economic rent) and all payments of rent to the government back to the year 1954.

The rows in Table 9 show the discount rates applied in the calculations for various lease classifications, the present value of true or implicit economic rent (after taxes) and the percent of this true economic rent captured by bonus, royalty and rental payments and total rent

---

[12] Taxes (corporate income taxes and the windfall profits tax) are treated as necessary costs of production and not as mechanisms used to transfer economic rent.

Table 9. Federal Government Capture of After Tax Economic
Using Representative Discount Rates

Lease Category	Discount Rate (Percent)	After Tax Rent ($M)	Percent of After Tax Rent Captured By: Bonus Payment	Royalty Payment	Rental Payment	Total Government Rent Capture (Percent)
All 1223 Leases In Aggregate	0	24,632,225	11.06	39.13	.45	50.64
	8	3,006,171	45.37	43.00	1.61	89.98
	10	1,858,912	63.37	45.87	2.19	111.43
	12	1,156,344	88.86	49.99	3.00	141.85
Big-8 Leases*	0	13,591,680	12.33	40.09	.48	52.90
	8	1,718,551	48.34	44.58	1.71	94.63
	10	1,073,616	66.65	47.71	2.33	116.69
	12	674,974	92.25	52.18	3.18	147.61
Big 9-20 Leases*	0	6,296,968	10.32	36.90	.39	47.61
	8	775,499	43.29	39.05	1.33	83.67
	10	481,563	60.63	41.04	1.78	103.45
	12	301,710	84.96	43.91	2.40	131.27
Non-Big 20 Leases*	0	4,743,483	8.42	39.35	.42	48.19
	8	512,129	38.59	43.71	1.66	83.96
	10	303,736	56.10	46.98	2.34	105.42
	12	179,662	82.66	51.95	3.34	137.95
Solo Leases	0	14,214,489	11.19	40.90	.55	52.64
	8	1,712,852	47.54	46.51	2.01	96.06
	10	1,047,156	67.59	50.47	2.78	120.84
	12	639,923	97.09	56.33	3.89	157.31
Joint Leases	0	10,417,679	10.89	36.72	.31	47.92
	8	1,293,322	42.50	38.36	1.07	81.93
	10	811,760	57.93	39.93	1.43	99.29
	12	516,424	78.66	42.13	1.91	122.70
Wildcat Leases	0	19,623,978	11.48	39.87	.52	51.87
	8	2,323,149	49.27	44.89	1.96	96.12
	10	1,415,289	70.17	48.51	2.72	121.40
	12	862,424	100.95	53.87	3.82	158.64
Drainage Leases	0	5,008,212	9.44	36.24	.14	45.82
	8	683,024	32.12	36.58	.39	69.09
	10	443,623	41.66	37.44	.49	79.59
	12	293,921	53.38	38.60	.60	92.58

*Attributed shares for jointly owned leases.

capture.

The bonus payment plays an increasingly large role in total rent capture as the discount rate increases. One would therefore expect bid levels to be quite sensitive to the costs of borrowing investment funds. The bonus payment is a front-end payment which, once paid, is independent of management decisions made later in the life of the lease. This contrasts with royalty and rental payments. The royalty payment is contingent on production while the rental payment is contingent on non-production. Royalty payments allow some risk to be shifted from lessee to lessor. In the absence of a royalty stipulation, one would expect the size of the bonus payment to increase; i.e., one payment is a trade-off against the other. The size of the increase in the bonus payment resulting from removal of the royalty would depend not only on the discounted value of the royalty payments, but also on the larger ultimate recovery of petroleum in the absence of royalty payments and on the risk premium bidders would assign for not being permitted to shift part of the risk to the resource owner.

The share of rent captured by the government varies positively with the assumed discount rate; the higher the discount rate, the larger the rent capture. This also applies to the individual means for capturing rent. The reason for this is that payments to the government are generally made earlier in the life of a lease than the time of any positive net income which may be earned by the lessee.

At higher discount rates, the earlier payment of economic rent to the government is given larger weight and the later generation of true economic rent in the process of production is given a smaller weight.

Bonus and royalty payments are by far the most important means for capturing rent. At a discount rate of 8 percent, they are approximately equal in importance. At higher discount rates, the bonus payment becomes more important. Rental payments are of minor significance. It is argued that these payments serve as an inducement to early production. But it is hard to see any economic justification for inducing production in advance of the time dictated by competitive market considerations. Rental payments add to the riskiness of the OCS industry in that they increase the difference in returns between non-productive and productive leases. Abolishing rental payments could be expected to lead bidders to offer higher bonus payments and thus the revenue loss (if any) to the federal govenment would be minor.

Table 9 demonstrates a necessary (and important) relationship between the discount rate assigned in computing economic rent generated and paid, and the internal rate of return for the category of leases being considered (as reported in Table 1). It can be seen that the percent of economic rent captured by the federal government is less than 100 percent when the discount rate is less than the internal rate of return for that category of leases, and greater than 100 percent when the discount rate is higher than the internal rate of return. For example, in the case of the aggregate of all 1,223 leases (for which the after tax internal rate of return is 9.02 percent) if the after-tax opportunity cost of capital is 10 percent, the federal government captures 111.43 percent of total economic rent; but if the appropriate discount rate is 8 percent, the federal government rent capture is reduced to 89.8 percent.

When the groupings of firms into Big-8, Big-9-20 and Non-Big-20 are compared, it is again evident that the Big-8 firms pay a larger percentage of economic rent to the federal government than smaller firms. This is true for all discount rates shown in Table 9 and for both bonus and royalty categories separately. An interesting finding is that the Non-Big-20 firms pay a substantially lower share of economic rent through bonus payments than the larger firms, but the contribution of royalty payments is greater than that of Big-9-20 firms and almost as large as that of the Big-8 firms. It appears that the Non-Big-20 firms have managed to implement a bidding strategy which shifts more risk to the resource owner than the Big-20 firms have, and this has been achieved without a reduction in the after-tax internal rate of return earned on their leases.

Leases won by solo bidders pay a higher percent of economic rent to the federal government than do leases won by joint bidders. This holds for all the discount rates shown in Table 9. It can also be seen that all means of rent collection contribute higher shares to total rent payment for solo than for joint leases. Nevertheless, solo leases pay out a larger proportion of their total economic rent in the form of royalty payments, implying that they shift a larger share of the risk to the federal government.

When wildcat and drainage leases are compared, it is apparent that the lessees of drainage tracts are doing substantially better than lessees of wildcat leases. It is especially important to note the small share of economic rent lessees of drainage leases pay in the form of bonus payments. Drainage leases pay a much smaller share of economic rent through rental payments. This is because drainage leases generally start producing much faster than do wildcat leases.[13] We have hypothesized earlier that the structure of competition for drainage leases may be different from that for wildcat leases because "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."[14]

---

[13] See Mead and Sorensen, op. cit., p. 98 and p. 106.
[14] Ibid, p. 19.

III. APPLICABILITY OF FINDINGS REGARDING COMPETITION IN 1954-1969 OCS LEASE SALES TO LATER LEASE SALES

III.1. Rationale for Study

The purpose of this analysis is to determine whether a model of winning bids for OCS leases issued from 1954 through 1969 is also valid for leases issued from 1970 to 1975. Regression analysis is used to statistically explain the observed variation in the high bid in terms of a number of independent variables. The explanatory variables used in the model are suggested by the economic theory of rational bidding behavior.[15]

Companies bidding for OCS oil and gas leases in the period from 1970 through 1975 faced an economic and political environment that differed markedly from the pre-1970 period. Some of the changes encountered by firms in the post-1969 period increased oil and gas development costs and thereby lowered lease values, while other changes raised prospective revenues and increased lease values. Economic theory suggests that if markets are functioning properly, increased costs (revenues) will be shifted back to the resource owner in the form of decreased (increased) bonus payments or other forms of economic rent. Prior to presenting our regression models, we will summarize the most important political-economic (including regulatory) changes that

---

[15] The economic theory of bidding behavior is not presented here. A more extensive discussion of the explanatory variables used in the regression models can be found in Mead and Sorensen, op. cit., pp. 59-83.

occurred between the years of our prior analysis (1954-1969) and the 1970-1975 period. The net effect of the changes outlined below was to increase bonus payments in the 1970-1975 period relative to the 1955-1969 period.

III.2. Major Changes in the Political-Economic Environment Between 1954-1969 and 1970-1975

III.2.1. Changes in Environmental Regulations

Since 1970, environmental regulations faced by the oil and gas industry, particularly with regard to offshore development, have become more stringent. This change can be traced back to the Santa Barbara oil spill of 1969 and its aftermath. Following this spill, a moratorium on wildcat leasing was enforced to allow time for a review of the ecological impact of OCS oil and gas production. The moratorium was in effect until the December 1970 sale off western Louisiana. The environmental review spawned new regulations which increased exploration and development costs for firms.

III.2.2. Changes in the Tax Treatment of Income from Oil and Gas

Also in 1970, in part due to the political impact of the Santa Barbara spill, and in part due to other political events, the tax treatment of income from oil and gas became less favorable. The tax legislation of 1969 lowered the percentage depletion allowance rate from 27.5% to 22% of gross income effective in 1970. The benefits of depletion were further reduced by the introduction of the minimum tax on preference income. It has been estimated that the minimum tax reduced the benefits of percentage depletion by an additional 2% to 20%.[16] In 1975 the percentage depletion deduction was eliminated for all integrated companies.[17] The result of the reduction and eventual elimination of the percentage depletion deduction was to increase the tax liability of OCS firms.

III.2.3. Changes in the Price and Cost of Crude Oil

The price of crude oil is perhaps the most important determinant of the value of oil and gas leases. Throughout the 1950's and 1960's, the wellhead value of crude oil in the U.S. tended to increase in nominal terms, and decrease in real terms. The record from 1950 through 1975 is shown in Table 10. Beginning in the early 1970's, crude oil prices increased under pressure from declining domestic oil and gas production and nationalization of middle eastern oil reserves. With the Arab-Israeli war of October 1973, world crude oil prices escalated sharply.

These developments would naturally lead to substantially higher bid prices for crude oil and gas leases, but were moderated by two contrary developments in other areas. First, on August 15, 1971, a wage and price freeze was

---

[16] Gerard M. Brannon, "Existing Tax Differentials and Subsidies Relating to the Energy Industry," in Studies in Energy Tax Policy edited by Brannon, Ballinger Publishing Co., 1975, pg. 5.

[17] A more complete discussion is found in Appendix 1, below.

Table 10. Crude Oil Prices and Costs, 1950-1975

Year	(1) Average Wellhead Price, U.S. Crude Oil	(2) Controlled Price, Lower Tier Oil	(3) Controlled Price, Upper Tier Oil	(4) Uncontrolled Imported Oil Refiner Cost	(5) Oilfield Machinery and Tools Price Index	(6) Average Wellhead Price U.S. Interstate Natural Gas
	(dollars/barrel)				(1967=100)	(cents/mcf)
1950	2.51				64.3	6.5
1955	2.77				79.7	10.4
1960	2.88				91.2	14.0
1965	2.86				95.2	15.6
1969	3.09				112.7	16.7
1970	3.18				118.7	17.1
1971	3.39				122.6	18.2
1872	3.39				127.3	18.6
1973	3.89				133.2	21.6
1974	6.74	5.03	10.13	12.52	157.8	30.4
1975	7.56	5.03	12.03	13.93	196.3	44.5

Sources:

(1) U.S. Bureau of Mines

(2), (3), (4) U.S. Department of Energy, Monthly Energy Review, August 1980

(5) U.S. Bureau of Labor Statistics, Producers Price Index

(6) U.S. Department of Energy, Energy Information Administration

imposed throughout the U.S. economy. The freeze was relaxed in three phases leaving only crude oil and petroleum products subject to controls. Nearly all OCS production was classified as lower tier or "old" oil and was subject to the most restrictive price controls. However, production from new leases was expected to be classified as upper tier or "new" oil and to be allowed more favorable prices. The latter prices were still below free market (import price) levels, as shown in Table 10. Thus, controls reduced the benefit of higher world market prices for crude oil. Second, while controlled oil prices increased substantially by 1975, costs of exploring for and developing new oil supplies also increased. For example, the cost of oil field machinery and tools increased 96.3 percent from 1967 to 1975 (see Table 10). Higher costs for new oil production further eroded the gains from increased world prices for crude oil.

III.2.4. Changes in Administrative Costs

As a consequence of price controls which established a multiple-tier price system, it became necessary for the government to develop systems to allocate low-priced crude and to equalize crude oil costs among refiners. These allocation and entitlements systems required expensive administrative bureaucracies within both the government and the complying firms. Additional private sector administrative costs ultimately reduce the value of leases.

III.2.5. Changes in the Price of Natural Gas

The attractiveness of natural gas increased markedly in the 1970's. In the early years of OCS leasing, natural gas was not highly sought after by bidders. Under price controls administered by the Federal Power Commission (FPC) since 1954, a relatively low natural gas price and the lack of gas transportation facilities often led to "flaring" when gas was discovered. By 1970, the infrastructure necessary to handle gas production was better established.

III.2.6. Changes in the Regulations Governing the Transportation of Natural Gas

Also in 1970, the FPC encouraged the participation of gas pipeline and distribution companies in OCS lease auctions by allowing them to pass on the costs of acquiring leases and exploring for natural gas, including the costs of dry holes. The resulting influx of small companies bidding in combines dominated lease auctions in the 1970-1975 period. Evidence is provided in Table 11 on a sale by sale basis.

III.2.7. Changes in the Worldwide Political and Economic Environment Affecting Oil and Gas Development

Since 1970, political and economic stability in the Middle East has deteriorated. The old concession system has been replaced by nationalization. Control of oil and gas production has shifted from international oil companies to host countries. The individual countries have attempted, with mixed success, to coordinate their price and output decisions through two cartel organizations, the Organization

Table 11
Summary Statistics for Gulf of Mexico
Oil and Gas Lease Sales, 1954-1975

Sale Date	Leases Issued	Average Number of Bidders	Average Bonus ($1,000)	Wildcat Leases	Drainage Leases	Big 8 Leases		Joint Leases	
						Number	Percent	Number	Percent
10-13-54	90	3.63	1,293	90	0	75	83	17	19
11-09-54	19	4.74	1,229	19	0	16	84	6	32
07-12-55	121	3.17	897	121	0	85	70	32	26
05-26-59	23	1.00	74	23	0	23	100	22	96
08-11-59	19	2.37	4,633	0	19	11	58	6	32
02-24-60	147	2.82	1,923	147	0	93	63	54	37
03-13-62	206	2.59	860	206	0	118	57	41	20
03-16-62	205	3.22	1,309	205	0	150	73	42	20
10-09-62	9	2.33	4,876	0	9	6	67	3	33
04-28-64	23	3.00	2,624	0	23	20	87	5	22
03-29-66	17	3.71	5,226	0	17	13	76	6	35
10-18-66	24	2.92	4,132	24	0	18	75	11	46
06-13-67	158	4.60	3,228	158	0	116	73	67	42
05-21-68	110	4.75	5,417	110	0	47	43	32	29
11-19-68	16	2.06	9,367	0	16	12	75	6	38
01-14-69	20	1.70	2,202	12	8	16	80	8	40
12-16-69	16	3.63	4,182	8	8	14	88	4	25
07-21-70	19	3.00	5,146	0	19	6	32	4	21
12-15-70	119	8.57	7,120	119	0	61	51	60	50
11-04-71	11	2.73	8,755	0	11	7	64	4	36
09-12-72	62	5.02	9,449	62	0	52	84	42	68
12-19-72	116	5.90	14,358	116	0	64	55	84	72
06-19-73	100	5.46	15,914	96	4	41	41	90	90
12-20-73	87	4.26	17,139	75	12	81	93	56	64
03-28-74	91	4.10	22,995	77	14	63	69	66	73
05-29-74	102	3.12	14,428	102	0	62	61	62	61
10-16-74	136	2.32	10,494	128	8	102	75	80	59
02-04-75	113	2.07	2,431	113	0	82	73	48	43
05-28-75	86	1.91	2,708	83	3	61	71	44	51
07-29-75	66	2.42	2,473	66	0	50	76	33	50

of Petroleum Exporting Countries (OPEC) and the Organization of Arab Petroleum Exporting Countries (OAPEC). The most notable impact of this activity has been the sharp increase in the world price of crude oil. As a secondary impact, a crude oil shortage psychology has developed. This impact has been reinforced by the peaking of gas reserves (1967) and oil reserves (1970) in the United States. For both resources, declining reserves have led to declining production. The long-standing excess U.S. crude oil production capacity, as reflected in low market demand prorationing production allowables, came to an end in the Spring of 1972 when the Texas Railroad Commission authorized a 100 percent allowable factor. Firms in the oil business became acutely aware of their need to rebuild reserves through new exploration and development. The most promising source of large new domestic reserves was the U.S. Outer Continental Shelf.

After two decades of leasing federal Gulf of Mexico lands, bidders started to realize in the early seventies that the most promising tracts had already been leased. A decrease in bidding intensity was expected[18] and occurred. Despite price increases for crude oil permitted in 1974 under the price control system, the average winning bonus bid for leases issued in the 1975 sales was significantly below the level of the 1970-1974 lease sales. The Gulf of Mexico attracted fewer bidders who bid less for the leases

---

[18] See Oil and Gas Journal, "Huge Bonus-Bid Sales May Be Over in the Louisiana Gulf," April 22, 1974, pp. 59-61.

offered for sale (see Table 11).

The major factors listed above, plus other less obvious forces which may have affected the attitude of bidders concerning the value of oil and gas leases, produced a sharp increase in the demand for leases and in the bids submitted. Table 12 shows that the average number of bidders per tract leased increased from 3.33 in the 1954-1969 period, to 4.14 in the 1970-1975 years. The average nominal high bid increased nearly five-fold from $2,228,831 per tract in the first period, to $10,864,084 in the second.

III.3. The Problem of Separating the Effects of Concomitant Changes in the Political and Economic Environment

These major changes, which have all occurred since 1969, present a sharp contrast with the 1954-1969 period of relative political and economic stability in the oil and gas industry. The qualitative nature of many of the changes discussed above makes it impossible to separate the impact of each. To do so would require the use of proxy variables for each type of change, which in most cases do not exist. Futhermore, if suitable proxy variables could be found, it is likely that many of the proxies would be highly correlated with one another making it econometrically impossible to distinguish their individual impact. Only their combined effect is estimated in our comparison of bidder behavior in the 1954-1969 period with that in the 1970-1975 period.

III.4. A Review of Prior Regression Variables

TABLE 11-A

SUMMARY STATISTICS FOR WILDCAT AND DRAINAGE LEASES

	Average High Bid ($1000)	Average Number of Bidders per Tract Leased	Average Number of Wells Drilled In First 24 Months	Number of Leases Issued	Percent Joint Bids		Percent Solo Bids		Total
					Big-8	Non-Big-8	Big-8	Non-Big-8	All Firms
Period 1954-1969									
Drainage	4,729	2.76	6.06	100	27.	7.	50.	16.	100.0
Wildcat	2,006	3.38	1.29	1123	22.8	6.4	44.5	26.3	100.0
Total	2,228	3.33	1.68	1223	23.1	6.5	45.0	25.4	100.0
Period 1970-1975									
Drainage	15,546	2.63	5.07	71	28.2	12.7	33.8	25.4	100.0
Wildcat	10,543	4.24	2.24	1037	40.1	12.2	25.7	12.2	100.0
Total	10,864	4.14	2.42	1108	39.9	20.8	26.2	13.1	100.0

The point of departure for our analysis is the regression model developed in our earlier report which uses high bid as the dependent variable.[19] Model 1 from that report is reproduced below with a brief discussion of our earlier findings.

III.4.1. Log of the Number of Bidders (LNNBIDS)

The number of bidders for a lease is a measure of the intensity of competition. Economic theory indicates that this variable is directly related to the dependent variable (i.e. the more competition for a lease, the higher the bonus bid, *ceteris paribus*). Consistent with this theory, LNNbids was found to have a significant positive sign.

III.4.2. Log of Present Value of Production (LNPVPDV)

LNPVPDV is a proxy variable for the perceived quality of a lease. The hypothesis here is that firms are willing to pay more for leases which ultimately prove to be productive. LNPVPDV has a positive and significant influence on high bid as expected.

III.4.3. Log of Number of Acres (LNACRES)

The size of a prospective lease tract is another proxy variable for the perceived quality of the tract. For a geological sructure of a given thickness of possible hydrocarbon bearing rock, the larger the area of the tract, the larger the expected reserves. LNACRES has the expected

---

[19] Mead and Sorensen, *op. cit.*, p. 80.

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) positive and significant sign.

III.4.4. Log of Water Depth (LNWATDEP)

Greater water depth implies larger prospective costs for such items as platforms and pipelines. LNWATDEP is a proxy variable for expected production costs. Economic theory suggests that firms will tend to bid less for leases having higher prospective costs. The coefficient of water depth is negative and significant which is consistent with prior expectations.

III.4.5. Log of Number of Wells Drilled in 24 Months (LNWELL24)

Profit maximization induces firms to explore the most promising leases first. In this respect the number of wells drilled in the first 24 months of the lease is a proxy for the perceived quality of the lease. Note that this variable complements LNPVPDV in that it does not depend on actual production. In the regression analysis LNWELL24 was found to have the expected positive significant sign.

III.4.6. Joint Ventures Versus Solo Bid Leases (JOINT01)

Two contradictory hypotheses may be suggested concerning the impact of joint bidding on high bid. First, because of risk-spreading by firms submitting joint bids, it might be expected that winning bids submitted by joint bidders should tend to be higher than winning solo bids. Joint bidding might allow small firms to participate in what would have otherwise have been too risky a prospect, thus increasing the number of bidders. But on the other hand, when two or more bidders combine to submit a single bid, the number of bidders has been reduced and consequently joint bidding might result in lower bids. The explanatory variable JOINT01 has a positive and significant sign. This result does not support an anti-competitive hypothesis for the impact of joint bidding; it is consistent with hypotheses emphasizing the advantage to the government of risk spreading.

III.4.7. Large Versus Small Firms (BIG801)

In recent years there has been considerable discussion suggesting that large firms have an advantage over small firms in competing for OCS leases. The regression results do not support this hypothesis. The regression coefficient of BIG801 is not significantly different from zero.

III.4.8. Drainage Versus Wildcat Leases (DWILDR)

Due to the decreased uncertainty concerning the existence of hydrocarbons in a drainage tract, it is expected that (*ceteris paribus*) winning bids on drainage tracts will be higher than winning bids on wildcat tracts. The coefficient of the drainage-wildcat dummy variable is positive and significant, as expected.

III.5. Revision of Prior Regression Variables for Generalizing Model to Later Data Base

The task of determining whether prior regression results can be generalized to later lease sales is analyzed by means of three regression models run on different data bases. The models are discussed successively as they relate to the prior model and to each other.

The data base for Model 2 (shown later) is similar to that used for Model 1. The primary difference in the two data bases is the omission of 1954 data from the Model 2 data base. (The reason for the omission of the 1954 data is found below with the discussion of the new regression variable SHPASTL.) There are 1114 leases in the Model 2 data base covering the period 1955 through 1969.

The dependent variable in Models 2 through 4 is the natural log of the real high bid. The real high bid, expressed in 1967 dollars, is the nominal high bid deflated by the Producer Price Index for manufactured goods. One of the expected problems of extending our analysis of pre-1970 lease sales to later sales is the onset of rapid inflation in the post-1969 period. By casting our model in real terms we hope to correct for this problem.

Independent variables LNNBIDS, LNACRES, LNWELL24, BIG801, and JOINT01 are common to both Models 1 and 2. DRAIN01 is the redefined drainage-wildcat dummy variable. It differs from DWILDDR in that twenty leases which were improperly classified in our earlier study were reclassified here.

The variables LNPVPDV and LNWATDEP found in Model 1 are omitted from Model 2. LNPVPDV, the log of the present value of production, is not included for methodological reasons. This variable is defined as the present value of historical gross production for each lease through 1978, discounted at 10%. Since our intent is to determine if the regression model based on pre-1970 data can be generalized to the post-1969 leases this variable must be omitted since it is not available over a sufficient time period for the later period leases. LNWATDEP, the log of water depth was omitted because complete information on this variable for post-1969 leases was unavailable.

III.5.1. <u>New Variables Introduced Into the Model</u>

Several new variables have been introduced into the regression analysis which were not used in Model 1. The first, SHPASTL, is defined as the share of past OCS leases held by the winning firm. In the case of a joint winning bid, SHPASTL is defined as the weighted average of the share of past leases held by the participants in the joint venture. The weights are determined by the percentage of each firm's working interest in the winning bid. The share of past leases was computed individually for the 20 largest Gulf of Mexico OCS lessee firms (as determined by the total lease holdings of each firm in 1969). Each Non-Big-20 firm was allotted an average share of the leases not won by the larger firms. At the time of the first lease sale (1954) the share of past leases held by all firms is undefined. To circumvent this problem, 1954 leases were eliminated from the model. Our hypothesis is that the larger the share of past leases, the more experienced the company will be in operating Gulf of Mexico leases and the better developed its infrastructure. This would lead to lower production costs for the firm which could in turn bid more for a lease and still guarantee itself a normal profit. Thus the expected sign of this variable is positive.

Another new set of variables introduced for the first time in Model 2 are AREA1, AREA2 and AREA3. These are dummy variables reflecting the geographical area of the lease. Thus they reflect general features of the environment which are common to each area and which are of importance to bidders.[20] AREA2 is south of the Mississippi delta, flanked by AREA1 to the west and AREA3 to the east. More precisely, the western boundary of AREA2 corresponds to the western boundary of the West Cameron area while its eastern boundary corresponds to the eastern boundary of the South Timbalier area. The rationale for this classification is that sedimentary conditions are believed to be sufficiently similar <u>within</u> a particular AREA and sufficiently different <u>between</u> AREAS such that a distinction was merited.

---

[20] Geographical area and geological trend classifications were developed in cooperation with USGS personnel in Reston, Virginia, and Metarie, Louisiana. We particularly recognize the contribution of George Dellagiarino in Reston.

The contribution of the AREA variables to our estimated high-bid models was tested statistically[21] and found to be significant at the 1 percent level. Thus the null hypothesis of no significant differences in bidding behavior between the geographical areas could be rejected.

It should be noted that in the regression models reported below, the effect of AREA3 is included in the intercept term, only AREA1 and AREA2 appear explicitly among the explanatory variables.

Finally new dummy variables are introduced in Model 4 (shown later) to reflect the effect of each individual lease sale on the high bid. The lease sale dummy variables serve two purposes. The first is to capture the many qualitative differences discussed in Section 3.2 above (affecting the political and economic environment) as well as qualitative differences unique to each lease sale. A second reason for including lease sale variables is to correct for econometric problems associated with the pooling of cross-section and time series data.

III.5.2. New Variables Tested and Rejected

A number of regression models other than those reported in Models 2 through 4 were estimated. Some of the independent variables which yielded unsatisfactory results are discussed below.

---

[21] The statistical tests which were applied are described in J. Johnston, Econometric Methods, 2nd ed. (New York: McGraw-Hill Book Company, 1972), pp.192-207.

a. Months to First Discovery (or First Production)

Months to first discovery is a proxy variable for the quality of a lease. However, data for this variable are not available in the LPR data base. An alternative proxy for lease quality is months to first production. The use of this variable suffers from several definitional problems. First, only annual data are available for production. Secondly, the months (or years) to first production is undefined if the lease proves to be dry. These definitional problems dictated the removal of this variable from the model.

b. Changes in Product Price

Ceteris paribus, increases in the price of crude oil and natural gas would be expected to result in higher bids for OCS leases. The price of crude oil was used as a proxy for changes in product price. This variable was removed because it is collinear with lease sale dummy variables. The lease sale dummy variables are included because they convey a wider set of circumstances believed to affect bidding behavior than the product price proxy. In addition, econometric problems associated with a data base comprised of pooled cross-section and time series information are reduced by using dummy variables for sale years.

c. Money Left on the Table

Money left on the table is defined as the difference between the winning bid and the second highest bid. Among other factors, this variable serves as a proxy for the general uncertainty associated with resource values and the behavior of competitors. A large amount of money left on the table (MLOTT) indicates a general disagreement about the value of a lease.

This variable was eliminated from the regression models. Upon inspection it was discovered that MLOTT was highly correlated with the number of bidders. This creates serious problems for econometric estimation. Secondly, single bids were received for approximately 20% of all the leases in the sample. This poses definitional problems for the MLOTT variable in that there is no second high bidder in these instances. Alternative assumptions were made regarding the definition of MLOTT for single bid leases, but none of the definitions proved to be satisfactory.

d. <u>Changes in the Cost of Production</u>

Several variables, including the Producer Price Index for Manufactured Goods and for Oil Field Machinery and Tools were considered for use in the regression analysis as proxies for increases in the costs of production. Economic theory suggests that firms faced with higher production costs will tend to bid less for leases. These variables were found to be highly correlated with the lease sale dummy variables, and were therefore rejected.

e. Changes in the Level of Economic Activity

Economic theory suggests that general increases in the level of economic activity will lead to changes in the demand for oil and gas as fuel sources, ultimately leading to higher bids for OCS leases. As a measure of economic activity, the Gross National Product (GNP) for all U.S. goods and services was used as an independent variable. As was the case with proxy variables for changes in cost of production, the GNP variable was highly correlated with the lease sale dummy variables and consequently was omitted from the model.

f. Geological Age

Dummy variables designed to reflect the different geological ages of the hydrocarbon bearing formations in the Gulf of Mexico were used as independent variables. These variables did not add significant explanatory power to the equation relative to the variables AREA1 and AREA2 (geographical area variables) and were eliminated.

III.6. Revised Regression Analysis of 1954-1969 Lease Sales

Incorporating the changes to our prior Model 1 reported above, (i.e. removing LNPVPDV and LNWATDEP and adding SHPASTL, AREA1 and AREA2) our regression model was run for the periods 1955-1969 and 1970-1975 separately. The results are shown in Model 2. The results of these regressions are similar to those found in Model 1 of our earlier report.

MODEL 2

DEPENDENT VARIABLE: LOG. OF REAL HIGH BID,
1,114[#] LEASES, 1955-1969, AND 1108 LEASES, 1970-1975

R^2 (1955-69) = .6546
R^2 (1970-75) = .5413

	1954-69		1970-75	
VARIABLE	PARAMETER ESTIMATE	T-RATIO	PARAMETER ESTIMATES	T-RATIO
INTERCEPT	1.630784	2.9425*	5.673560	6.0169*
LNNBIDS	1.166331	30.4558*	0.952608	22.2470*
LNACRES	0.692572	10.4478*	0.350575	3.1427*
LNWELL24	0.553446	13.2010*	0.479247	10.4829*
DRAIN01	1.397216	11.4891*	0.712099	4.9341*
JOINT01	0.023922	0.3480	0.487518	6.3278*
BIG801	0.293723	3.6569*	0.114615	1.2819
SHPASTL	-3.985192	-5.2862*	0.306781	0.2034
AREA1	0.100642	1.1149	-0.275389	-2.8769*
AREA2	-0.033574	-0.4828	-0.361943	-4.1923*

*Significant at 5% (two tailed test).

[#]There were 1,223 leases issued in the period 1954 through 1969. By omitting the year 1954, the number of leases becomes 1,114.

LNNBIDS, LNACRES and LNWELL24 all have approximately the same parameter estimates as in the earlier report. The parameter estimate for DRAIN01 differs slightly due to reclassification of 20 leases improperly classified as drainage leases in the earlier data base and the now more properly classified as wildcat leases. In all instances, the signs and the significance levels of parameter estimates remained unchanged.

Our earlier results indicate that joint bids tended to be higher than solo bids. More detailed analysis showed that this higher bid price was restricted to the case of joint bids submitted by Big-8 firms for drainage leases only. In our present analysis, we find that the tendency for joint bids to be higher than solo bids disappeared in the 1955-1969 period. This point will be further discussed below in connection with our interaction variables procedure.

Earlier results also indicate no relationship between the size class of the high bidder and the amount of the winning bid. In the present study, BIG801 becomes a significant variable in the 1955-1969 years indicating that large firms tend to pay higher prices for leases relative to Non-Big-8 firms. Again, this issue will be further discussed below, using interaction procedures.

Of the three new variables, only the share of past leases (SHPASTL) showed a significant relationship to high bid. We find that in the years 1955 through 1969, the greater the share of past leases held by the winning bidder, the less the price paid for a lease. This result suggests a competitive advantage (in terms of bid price only) for firms that gained early experience in this lease-sale market. However, as we note below, this apparent advantage disappears in the years 1970-1975.

The Gulf of Mexico was divided into three geographical areas as described earlier. The results show that AREA1 and AREA2 do not differ in high bid to any significant degree from the area represented in the intercept term.

In sum, the explanatory power of the revised model (with regard to R-square) with the adjusted data base is almost identical to our earlier model. We now proceed to apply this new model to the bidding record for 1970-1975.

III.7. Regression Analysis of the 1970-1975 Lease Sale Records

To test the applicability of our regression model for subsequent leases, we have utilized the bidding record for the years 1970 through 1975. The results of this analysis are included in Model 2 for easy comparison with the results for the 1955-1969 period. The variables LNNBIDS, LNACRES, LNWELL24 and DRAIN01 that were important and significant explanatory variables in our original Model 1, remain significant with no changes in sign or significance. The other five variables, JOINT01, BIG801, SHPASTL, AREA1 and AREA2[22],

---

[22] Only JOINT01 and BIG801 of these five variables were included in our original Model 1. The other three have been

show no significant sign change between the two periods. However, they do show instability in significance levels. The R-square values show that the model explains 65 percent of the observed variation in high bid during the 1955-1969 period, and 54 percent during the 1970-1975 years.

III.8. Statistical Tests of the Comparability of the 1955-1969 Period to the 1970-1975 Period

We have performed three tests to determine whether the two time periods are the same with respect to the variables considered. The first directly tests for differences between the two time periods. The two estimated equations shown as Model 2 are based on two separate sets of data. In Model 3 we have combined the data sets to comprise all the leases issued in the entire 1955-1975 period. There are 2,222 leases in the combined data base. Unlike Model 2, Model 3 assumes that there is no difference between the estimated coefficients for the 1955-1969 period relative to the 1970-1975 period. The difference in the two periods is estimated using the dummy variable, POST6901. This variable takes a value of zero for leases issued in the earlier period and one for leases issued in the later period. As expected, the coefficient of POST6901 is positive and highly significant, demonstrating that there was an upward shift in the high bid level in the post-1969 period.

---

added in this present study.

Model 3

DEPENDENT VARIABLE: LOG. OF REAL HIGH BID,
2222 LEASES, 1955-1975

R^2 = .6606

VARIABLE	PARAMETER ESTIMATE	T-RATIO
INTERCEPT	2.906441	5.9886*
LNNBIDS	1.067261	37.1174*
LNACRES	0.558608	9.6292*
LNWELL24	0.499592	16.2876*
JOINT01	0.232457	4.6262*
BIG801	0.251115	4.2906*
DRAINo1	1.078793	11.4233*
SHPASTL	-3.048664	-4.4905*
ENV1	-0.078443	-1.2068
ENV2	-0.194444	-3.5617*
POST6901	0.909735	19.5038*

*Significant at 5% (two tailed test).

A related, but slightly different question is whether our regression model, with its coefficients as developed from the 1955-1969 data base can be used to accurately predict post-1969 high bids. Two non-parametric statistical tests have been employed to answer this question.[23]

Both tests discussed here, the sign test and the Wilcoxon signed rank sum test, are founded on the premise that if the pre-1970 regression analysis is valid in the post-1969 period, then on average, actual post-1969 high bids will equal predicted high bids for that period arrived at by using the pre-1970 model. Our null hypothesis is that the structure of bidding has remained unchanged over the entire period from 1955 to 1975. The alternative hypothesis is that there has been a change in bidding structure over that period.

For the sign test, if the null hypothesis is true, actual high bids will exceed predicted high bids half the time and vice versa. A random variable is constructed from the comparison of actual to predicted high bids. The variable takes the value of one if the predicted high bid exceeds the actual high bid and zero otherwise. The sum of this random variable for all 1970-1975 leases is our test statistic. The statistic has a binomial distribution with a mean and variance of one-half and one-fourth the number of

---

[23]For a thorough discussion of non-parametric statistical techniques, see Mosteller and Rourke, Sturdy Statistics, Non-Parametrics and Order Statistics, Addison-Wesley Publishing Co., Menlo Park, Ca., 1973.

leases in the sample respectively. With 1,108 leases issued in the sample period, the mean and variance of the distribution are 554 and 277 respectively. Given the large sample size, the distribution of the test statistic can be approximated by a normal distribution with the same mean and variance.

In our sample of 1970-75 leases it was found that actual high bids exceeded predicted high bids 70% of the time. Assuming that the structure of bidding has remained unchanged over the period from 1954 to the present, the probability of this occuring is nil.[24] Thus we reject the hypothesis that the structure of bidding has remained the same from 1954 to 1975.

The Wilcoxon ranked sum test provides an alternative method of testing the hypothesis that the structure of bidding has remained unchanged. In constructing the Wilcoxon statistic, it is assumed that if the null hypothesis is true, then the predicted high bids are unbiased estimates of actual high bids. The Wilcoxon statistic is constructed as follows:

(a) For each lease in the 1970-75 sample a random variable equal to the difference between the predicted and actual high bids is computed. This random variable will be positive if the predicted high bid exceeds the actual high bid and negative otherwise.

---

[24] the Z score is 13.52.

(b) Two new random variables are constructed from the random variable computed in (a). The new variables are (1) the absolute value of the variable and, (2) the sign of the variable.

(c) The absolute value of the differences in predicted and actual high bids are ranked. The rank of the difference forms still another random variable.

(d) A final random variable, the signed rank, is constructed for each lease as the product of the rank from (c) and the sign from (b). The Wilcoxon statistic is the sum of the signed ranks.

The Wilcoxon statistic has a mean value of zero and a variance of

$$\sigma^2 = \frac{n(n+1)(2n+1)}{6}$$

where n is the number of leases in the post-1969 data base. For 1,108 leases the standard deviation (the square root of the variance) of the Wilcoxon statistic is 21,308. While the actual distribution of the Wilcoxon statistic is somewhat complicated, for large samples the distribution can be approximated by a normal distribution with zero mean and variance as expressed above.

In our sample of post-1969 leases, the Wilcoxon statistic was found to have a value of 322,546. As was the case with the sign test, the Wilcoxon test rejects the hypothesis that in fact the structure of bidding has been unchanged.[25] These tests establish that statistically significant differences exist between the two time periods.

III.9. Further Analysis of Differences in Bidding Behavior in the Period 1970-1975 as Compared to the Period 1955-1969

III.9.1. Methodological Approach

The regression models and the non-parametric statistical tests reported above show that there was a significant upward shift in the level of high bids in the post-1969 period. In addition, the regression models demonstrate that there were changes in the coefficients of explanatory variables and that some variables changed from insignificant to significant and vice versa. In this section, a further analysis of the differences between the two periods is presented. At issue in this section is whether the contribution of specific explanatory variables changed significantly from one period to the next. Statistical tests are presented for slope coefficients as well as for dummy variables (which only affect the intercept term).

In order to make such tests possible, it was necessary to combine the two estimated equations shown in Model 2 and use the pooled data set consisting of all the leases issued over the entire 1955-1975 period. The methodological approach that we use in this section is commonly referred to

---

[25] The Z score is 15.14. level.

in econometrics as covariance analysis.[26] This type of analysis is often used to correct for the problems of pooling cross section and time series data. To see how these problems are relevant for the present analysis, consider a regression model which does not explicitly take into account in what area and at what time a lease is issued. This model would implicitly assume that area and time do not affect regression estimates. Thus the competitive structure would be assumed to be the same for offshore Florida tracts as for offshore Texas tracts. The method of covariance analysis can be thought of as a regression strategy that allows one to test statistically for the validity of these assumptions.

Models 4 and 5 are the final outcomes of a number of regression stages. At each stage a test was performed to check for statistical differences in intercept and/or slope coefficients between time periods and between the cross-sections represented by the area dummy variables. Our regression strategy was, however, limited by two simplifying assumptions. First, it was assumed that differences between areas could be represented by dummy variables such that only the intercept term was affected. The reason for this assumption was to keep the number of explanatory variables at a reasonably low level. Second, we made a distinction between only two time periods, the pre-70 and post-69 periods. An alternative approach would have been to define

---

[26] A comprehensive discussion of this type of analysis can be found in J. Johnston, op. cit., pp. 192-207.

each lease sale as a different "time period". This approach was rejected since it would involve too many explanatory variables to test for differences in slope coefficients and intercept terms between the 35 lease sales in our sample. Furthermore, the use of only two time periods would allow a more direct test of the hypothesis that there was a shift in the competitive structure in the post-1969 as compared to the pre-1970 period.

In the course of arriving at Models 4 and 5, the following hypotheses were tested successively and rejected at the 1 percent level of significance:

(1) Bidding behavior is homogeneous in the three geographical areas.

(2) The intercept term in the 1970-75 period is not different from the intercept term in the 1955-69 period.

(3) The slope coefficients in the 1970-75 period are not different from the slope coefficients in the 1955-69 period.[27]

The outcomes of these tests give solid support to the finding that there was a substantial change in bidding behavior from the pre-70 to the post-69 period. Specifically, the rejection of the second hypothesis above rein-

---

[27] The slope coefficients are the coefficients of LNNBIDS, LNACRES, LNWELL24, and SHPASTL. Note that this is a test on all slope coefficients simultaneously. Model 5 does, however, allow one to identify which particular slope coefficients were subject to a significant change from one period to the next.

forces our conclusion that the level of high bids in the later period was significantly higher than in the earlier period. Models 4 and 5 allow a further identification of the changes which took place. Using Model 4, we will first test for inter- and intra-period differences in interaction variables involving firm size, bid type and lease type. Second, we will use Model 5 to test for differences in the slope coefficients.

III.9.2. Analysis of Bidding Behavior by Firm Size, Type of Bid and Type of Lease

Apart from the amounts of the high bids measured by our dependent variable, there were important changes in the number of leases won by firm size, type of bidding (joint or solo), and type of lease (drainage or wildcat) in the two time periods. While the share of leases won by Non-Big-8 firms increased slightly from 31.9 percent in the first period to 33.9 percent in the second, these smaller firms increased their share of drainage leases won from 23.0 percent in the first period to 38.0 percent in the second. Use of joint bidding more than doubled for all firms from 29.6 percent in period one to 60.7 percent of all high bids in period two. But small firms expanded successful joint bidding more than their larger competitors. Joint bidding by small firms increased from 20.3 percent to 61.4 percent while the Big-8 firms increased their joint bidding shares of high bids from 34.0 percent to 60.4 percent. The record is shown in Table 12.

TABLE 12

NUMBER OF LEASES IN EACH INTERACTION CATEGORY

	Number of Leases			
	Wildcat		Drainage	
	Joint	Solo	Joint	Solo
Period 1954-69				
Big-8	256	500	27	50
Non-Big-8	72	295	7	16
Period 1970-75				
Big-8	422	266	20	24
Non-Big-8	222	127	9	18

Model 2 makes a distinction between Big-8 and Non-Big-8, solo and joint, and wildcat and drainage leases. This model shows that the coefficient of BIG801 becomes insignificant in the 1970-1975 period while the coefficient of JOINT01 becomes positive and significant. But one cannot determine from Model 2 whether the impact of, say, JOINT01 in the 1970-1975 period (period 2) was significantly different from that in the period 1955-1969 (period 1). A different specification, Model 4, is needed to answer this question.

In Model 4, the coefficients of BIG801, JOINT01 and DRAIN01 have been decomposed into coefficients of groupings of leases characterized simultaneously by firm size of the winning bidder, winning bid type and lease type. Analogously to Model 2 of our earlier report[28], we define lease categories based on interactions of the following variables: BIG801, NBIG801, SOLO01, JOINT01, WILD01 and DRAIN01. Dummy variables were defined for each of the possible cases. For example, a drainage lease won by a Big-8 firm with a joint bid was designated B8JD. This dummy variable was given the value 1 for all leases with these properties, and zero otherwise. The set of interaction variables so defined are: B8JD, NB8JD, B8SD, B8JW, NB8JW, B8SW, and NB8SW.

Model 4 has been estimated using the pooled data set involving leases issued in both period 1 and period 2. Con-

---

[28] Mead and Sorensen, op. cit., p. 81.

MODEL 4

DEPENDENT VARIABLE: LOG. OF REAL HIGH BID,
2,222 LEASES, 1955-1975.

R^2 = .6730

VARIABLE	PARAMETER ESTIMATE	T-RATIO
INTERCEPT	2.188007	3.5307*
LNNBIDS1	1.175444	28.5403*
LNACRES1	0.687895	9.6693*
LNWELL241	0.535425	11.9827*
SHPASTL1	-4.213599	-5.0476*
LNNBIDS2	0.946690	23.7579*
LNACRES2	0.354699	3.4022*
LNWELL242	0.464148	10.9377*
SHPASTL2	0.617989	0.4309
B8JW1	-0.054696	-0.6015
B8JD1	1.641289	7.7081*
B8SD1	1.265086	7.5800*
NB8JW1	-0.263857	-1.8130
NB8JD1	1.120896	2.9395*
NB8SW1	-0.305976	-2.9786*
NB8SD1	0.869181	3.1540*
B8JW2	4.018962	3.7827*
B8JD2	4.828798	4.5259*
B8SW2	3.430745	3.2102*
B8SD2	4.542573	4.3835*
NB8JW2	3.806595	3.5777*
NB8JD2	4.410406	4.1643*
NB8SW2	3.522219	3.3196*
NB8SD2	3.740163	3.5666*
AREA1	-0.073631	-1.1227
AREA2	-0.182374	-3.3250*

*Significant at 5% (two tailed test).

sequently, each of the explanatory variables has been labeled to denote the time period for which they are relevant. In Model 4, a "1" following a variable name (except AREA1) means that the variable is relevant for period 1 only, and a "2" (except AREA2) means that the variable is relevant for period 2 only. Model 4 is thus a combination of the two time periods in Model 2 except that the interaction variables replace the variables BIG801, JOINT01 and DRAIN01.[29]

In Model 4, the base case (contained in the intercept term) consists of all wildcat leases issued in the 1955-1969 period to a Big-8 firm which submitted a solo bid (B8SW1). Thus the coefficients of the other interaction variables included in the model are to be compared with this base case only. Even if the coefficients of two other interaction variables differ, it is not possible to conclude from Model 4 whether the difference is statistically significant or not. One way to test statistically for the difference is to run Model 4 sixteen times, each time with a different

[29] More precisely, the variables whose names end with "1" always take on the value 0 for observations coming from period 2. Analogously, variable names ending with "2" are given the value 0 for observations coming from period 1. The reader will notice that the coefficients of LNNBIDDS, LNACRES, LNWELL24 and SHPASTL in Model 4 have changed slightly from their counterparts in Model 2. This is because regression coefficient estimates do not depend on the relationship between a variable and the dependent variable only, but also on the relationship to all other variables in the model. Since Models 2 and 4 involve different sets of explanatory variables, the small deviations are accounted for by differences in correlation patterns between the explanatory variables in the two models.

interaction variable as the base case. Based on these runs, Table 13 was generated. It reports the t-ratios for testing the null hypothesis that any pair of interaction variables have the same impact on high bid. The alternative hypothesis is that they do not have the same impact on high bid.

It can be seen from the main diagonal of the northeastern quarter of Table 13 that leases in all the interaction categories received significantly higher bids in period 2 than in period 1 (compare B8JD2 to B8JD1, NB8JD2 to NB8JD1, etc.). This is not surprising in view of our finding that there was an upward shift in the level of the high bids in the post-1969 period. The interaction variables affect the intercept of the estimated equation only. Thus the upward <u>shift</u> in the high bid will be captured by the interaction variables which are defined for period 2. Table 13 shows that the shift was not confined to particular interaction categories, but was common to all of them.

In order to facilitate intra- and inter-period comparisons, Table 14 was derived from Table 13. This table confirms one of the important findings reported earlier[30], that in the pre-1970 period, high bids for drainage leases were significantly higher than high bids for wildcat leases, irrespective of firm size of the winning bidder or form of bidding. It can also be seen that in the earlier period,

[30] Mead and Sorensen, <u>op</u>. <u>cit</u>., p. 76.

TABLE 13

T-RATIOS FOR COEFFICIENTS OF INTERACTION VARIABLES IN MODEL 4 WITH VARYING BASE CASE

	B8JD1	NB8JD1	B8SD1	NB8SD1	B8JW1	NB8JW1	B8SW1	NB8SW1	B8JD2	NB8JD2	B8SD2	NB8SD2	B8JW2	NB8JW2	B8SW2	NB8SW2
B8JD1		-1.3	-1.6	-2.5*	-7.9*	-8.1*	-7.7*	-9.2*	3.1*	2.7*	2.9*	2.1*	2.3*	2.1*	1.7	1.8
NB8JD1	1.2		.4	-.6	-3.1*	-3.7*	-2.9*	-3.8*	3.4*	3.0*	3.2*	2.4*	2.6*	2.4*	2.1*	2.2*
B8SD1	1.6	-.4		-1.3	-7.2*	-7.1*	-7.6*	-8.3*	3.4*	3.0*	3.3*	2.4*	2.7*	2.2*	2.1*	2.2*
NB8SD1	2.5*	.6	1.3		-3.4*	-4.0*	-3.2*	-4.4*	3.8*	3.4*	3.6*	2.8*	3.0*	2.8*	2.5*	2.6*
B8JW1	7.9*	3.1*	7.2*	3.4*		-1.5	.6	-2.7*	4.6*	4.2*	4.4*	3.6*	3.8*	3.6*	3.3*	3.4*
NB8JW1	8.1*	3.6*	7.1*	4.0*	1.5		1.8	-.3	4.8*	4.4*	4.6*	3.8*	4.0*	3.8*	3.4*	3.6*
B8SW1	7.7*	2.9*	7.6*	3.2*	-.6	-1.8		-3.0*	4.5*	4.2*	4.4*	3.6*	3.8*	3.6*	3.2*	3.3*
NB8SW1	9.2*	4.0*	8.3*	4.4*	2.7*	.3	3.0*		4.8*	4.5*	4.7*	3.9*	4.1*	3.9*	3.5*	3.6*
B8JD2	-3.1*	-3.4*	-3.4*	-3.8*	-4.6*	-4.8*	-4.5*	-4.8*		-1.1	-.9	-3.4*	-3.6*	-4.3*	-6.0*	-5.5*
NB8JD2	-2.7*	-3.0*	-3.0*	-3.4*	-4.2*	-4.4*	-4.2*	-4.5*	1.1		.3	-1.7	-1.2	-1.7	-2.8*	-2.6*
B8SD2	-2.9*	-3.2*	-3.3*	-3.6*	-4.4*	-4.6*	-4.4*	-4.7*	.9	-.3		-2.5*	-2.3*	-3.0*	-5.1*	-4.2*
NB8SD2	-2.1*	-2.4*	-2.4*	-2.8*	-3.6*	-3.8*	-3.6*	-3.9*	3.4*	-1.7	2.5*		1.1	.3	-1.2	-.9
B8JW2	-2.3*	-2.6*	-2.7*	-3.0*	-3.8*	-4.0*	-3.8*	-4.1*	3.6*	1.2	2.3*	-1.1		-2.3*	-6.5*	-4.9*
NB8JW2	-2.1*	-2.4*	-2.2*	-2.8*	-3.6*	-3.8*	-3.6*	-3.9*	4.3*	1.7	3.0*	-.3	2.3*		-2.9*	-2.5*
B8SW2	-1.7*	-2.1*	-2.1*	-2.5*	-3.3*	-3.4*	-3.2*	-3.5*	6.0*	2.8*	5.1*	1.2	6.5*	2.9*		.7
NB8SW2	-1.8	-2.2*	-2.2*	-2.6*	-3.4*	-3.6*	-3.3*	-3.6*	5.5*	2.6*	-4.2*	.9	4.9*	2.5*	.7	

Note: Each entry gives the t-value for testing H_0: the column category has the same impact on high bid as the row category. A positive sign indicates that the coefficient of the column category is higher than that of the row category. * indicates significance (5% level, two tailed test). The table is symmetric with respect to the main diagonal except for change of sign.

TABLE 14

TESTS OF SIGNIFICANCE OF DIFFERENCE IN HIGH BIDS

	Period 1955-1969				Period 1970-1975			
	Lease Category				Lease Category			
Case 1. Comparison by Size of firm (Big-8 vs. Non-Big-8)	JW	SW	JD	SD	JW	SW	JD	SD
	*	**	*	*	**	*	*	**
	Lease Category				Lease Category			
Case 2. Comparison by type of lease (Drainage vs. Wildcat)	B8J	B8S	NB8J	NB8S	B8J	B8S	NB8J	NB8S
	***	***	***	***	***	***	*	*
	Lease Category				Lease Category			
Case 3. Comparison by form of bidding (Joint vs. Solo)	B8W	B8D	NB8W	NB8D	B8W	B8D	NB8W	NB8D
	*	*	*	*	****	*	****	*

*No significant difference between high bids

**Big 8 bids significantly higher than Non-Big-8 bids. (Relevant only for Case 1.)

***Drainage bids are significantly higher than wildcat bids. (Relevant only for Case 2.)

****Joint bids are significantly higher than solo bids. (Relevant only for Case 3.)

the form of the winning bid (whether solo or joint) had no significant impact on the high bid and that firm size was significant only in the case of solo-wildcat leases.

Table 14 further confirms our findings regarding two hypotheses relating to competition. First, in the 1970-1975 period, there is no evidence that Big-8 firms were able to buy leases at low prices relative to Non-Big-8 firms. Indeed, contrary evidence is shown in the cases of joint-wildcat and solo-drainage bids, where Big-8 firms bid significantly higher prices. Second, the 1970-1975 period shows no evidence that firms bidding jointly obtained leases at low prices relative to solo bidding firms. Again to the contrary, in cases of Big-8 wildcat and Non-Big-8 wildcat, joint bidding produced higher bid prices relative to solo bidding.

The two major changes in the 1970-1975 period relative to the 1955-1969 period were, first, the more aggresive bidding for drainage leases by the Big-8 firms and, second, the dominance with respect to high bid of joint bidding over solo bidding in the case of wildcat leasing.

III.9.3. Analysis of Differences Between Slope Coefficients in the 1970-1975 Period and The 1955-1969 Period

In Models 2 and 4 it can be seen that the estimated coefficients of variables affecting the slope of the estimated equation (LNNBIDS, LNACRES, LNWELL24, SHPASTL) experienced changes from one period to the next. Model 5 was specified to test whether the change was significant for each individual variable. It is identical to Model 4 except that the coefficients of LNNBIDS2, LNACRES2, LNWELL242 and SHPASTL2 now measure the difference in the impact on high bid in period 2 relative to period 1. Similarly, the t-ratios of these variables permit a direct test of the hypothesis that any slope coefficient is unchanged from one time period to the next.[31] This contrasts with Model 4 where all slope coefficients are measured as deviations from zero and all t-ratios test the hypothesis that the slope coefficients do not deviate from zero. It is possible to derive all the slope coefficients in Model 4 from Model 5 by addition of the relevant coefficients, and vice versa.

In Model 5 it can be seen that the log of number of bidders has a significantly lower impact on high bid in the second period as compared to the first period. But the average number of bidders increased by 24 percent in the post-1969 period as compared to the pre-1970 period (see Table 11), thus making up for the 19 percent drop in the estimated coefficient of LNNBIDS as shown in Model 5. This indicates that even if there was a decrease in the contribution of the marginal bidder to the high bid, the government,

---

[31] This approach has been suggested by J. Johnston, op. cit., p. 206. The reader will note the close analogy to the use of dummy variables and testing the coefficient of a dummy variable. A dummy variable measures the deviation from the intercept term given that a certain condition is satisfied. The coefficients of LNNBIDS2, LNACRES2, LNWELL242 and SHPASTL2 in Model 5 measure the deviation from the slope given that a lease is auctioned in period 2.

MODEL 5.

Dependent Variable:
Log. of Real High Bid,
2,222 Leases,
1955-1975.

R^2 = .6730

VARIABLE	PARAMETER ESTIMATE	T RATIO
Intercept	2.118007	3.5307*
LNNBIDS	1.175444	28.5403*
LNACRES	0.687895	9.6693*
LNWELL24	0.535425	11.9827*
SHPASTL	-4.213599	-5.0476*
LNNBIDS2	-0.228754	-3.9835*
LNACRES2	-0.333196	-2.6513*
LNWELL242	-0.071277	-1.1482
SHPASTL2	4.831588	2.9138*
B8JW1	-0.054696	-0.6015
BBJD1	1.641289	7.7081*
B8SD1	1.265086	7.5800*
NB8JW1	-0.263857	-1.8130
NB8JD1	1.120896	2.9395*
NB8SW1	-0.305976	-2.9786*
NB8SD1	0.869181	3.1540*
B8JW2	4.018962	3.7827*
B8JD2	4.828798	4.5259*
B8SW2	3.430745	3.2102*
B8SD2	4.542573	4.3835*
NB8JW2	3.806595	3.5777*
NB8JD2	4.410406	4.1643*
NB8SW2	3.522219	3.3196*
NB8SD2	3.740163	3.5666*
FIREA1	-0.073631	-1.1227
AREA 2	-0.182374	-3.3250

* Significant at 5% level (2 tailed test)

as the resource owner, still received a net benefit through an increase in the number of bidders participating in the lease auctions.

The log of acres also shows a negative and significant change in the 1970-1975 period. We hypothesize that areas believed to be of high quality were divided into a larger number of leases (smaller acreage) in the post-1969 period than in the pre-1970 period. But we have not been able to test this hypothesis statistically.

Another proxy variable for perceived lease quality, the log of number of wells drilled within the first 24 months after the lease auction, shows a negative but insignificant change in the post-1969 period. One cannot therefore, reject the hypothesis that the impact of this variable was the same in both periods.

The variable SHPASTL (share of leases issued in the past owned by the winning bidder) has a significant, negative effect on high bids in the pre-1970 period. Apparently, firms that had acquired a relatively large number of leases had an advantage over other firms in their ability to buy leases at a lower price in this period. A possible explanation for the negative and significant sign of SHPASTL in the pre-1970 period is that the effect of the so-called "winners-curse" was more serious for the inexperienced companies than for the experienced companies. Model 5 indicates that the bidding strategy of the inexperienced firms became similar to that of the experienced firms over time. The coefficient of SHPASTL changed significantly from the first to the second period to become insignificant (see Model 5). The advantage held by firms owning more leases in the pre-1970 period was eliminated in the later period, perhaps through a process of information dissemination and adjustment of bidding strategies.

APPENDIX 1

The Tax Treatment of Oil and Gas Income from the OCS

Introduction

This appendix decribes the relevant federal and state tax laws which underlie our estimation of the after-tax internal rate of return on OCS oil and gas leases issued over the period 1954-1969. The following aspects of oil and gas taxation are considered:

1) Corporate tax rates
2) Corporate income tax surcharge
3) Cost depletion
4) Percentage depletion
5) Expensing of intangible drilling costs
6) Depreciation of tangible drilling costs
7) Expensing of dry hole costs
8) Windfall profits tax
9) Investment tax credit
10) Capital gains
11) Minimum tax
12) State taxes

In order to simplify the analysis we assume that firms owning OCS leases file tax returns for the accounting period covering the calender year. Fiscal year accounting is not used in this analysis. Changes in relevant tax statutes effective between January and December are treated as applicable to the entire year unless otherwise noted. We further assume that all OCS investments are equity funded; hence, there are no interest deductions. Finally we assume that all OCS lessee firms have sufficient income and/or tax liabilities from non-OCS sources to fully utilize any tax advantage that results from OCS activity.

Corporate Tax Rates

The rate and structure of the corporate income tax has changed significantly from 1954 to the present. The current rate structure is progressive. Thus the marginal tax rate (the amount of tax paid on the last dollar of taxable income) increases as the level of taxable income increases. Since OCS lessees are relatively large firms, we assume that all income derived from OCS production is subject to the maximum marginal corporate tax rate. The corporate tax liability attributable to a particular OCS lease is therefore the product of the taxable income derived from that lease and the applicable marginal tax rate. Taxable income is defined as the gross income from the lease less royalty payments, production costs, and all other legal deductions. These deductions include cost or percentage depletion, expensing of intangible drilling costs, depreciation of tangible drilling costs, expensing of dry hole costs, expensing of lease abandonment costs, the windfall profits tax, and various state taxes. These deductions are discussed in subsequent sections.

The history of maximum marginal corporate tax rates from 1954 onward is given in Table 1.

Table 1. Maximum Marginal Tax Rates on Corporate Profits

Year	Tax Rate
1979-after	46%
1965-1978	48%
1964	50%
1954-1963	52%

Corporate Income Tax Surcharge

From 1968 through 1970, corporations were required to pay a surcharge in addition to the corporate income tax shown in Table 1. The surcharge was computed as as a percentage of the regular corporate tax, as indicated in Table 2.

Table 2. Corporate Income Tax Surcharge

Year	% of Corporate Tax
1971-after	none
1970	2.5%
1968-1969	10%
1954-1967	none

We account for the corporate surcharge attributable to OCS lease profits by altering the maximum marginal tax rate in the relevant years. Thus converted, the 48% regular tax rate becomes an effective tax rate of 52.8% in 1968 and 1969 and 49.2% in 1970.

Percentage Depletion and Cost Depletion

> Oil and gas deposits being exploited are to their owners wasting assets in the sense that any item of real capital may be a wasting asset to its owner; that is, use in production ordinarily diminishes its real capital value.[32]

The consumption of capital in the process of production is a cost to the firm. Firms are allowed to deduct this cost, in the form of depreciation, in arriving at taxable income. Depletion for mineral assets is analogous to ordinary depreciation in that it represents the wasting of an asset as production proceeds.

There are two methods of computing the depletion deduction, percentage depletion and cost depletion. The tax advantages of percentage depletion were eliminated for all integrated oil companies in 1975. Until 1975, OCS lessees were permitted to deduct from gross income the larger of percentage depletion or the more conventional cost depletion.

Cost depletion (which is similar to the "production method of depreciation") is computed in the following fashion:

The total production[33] from a given lease in the current tax period is divided by the total production from

---

[32]Stephen L. McDonald, Federal Tax Treatment of Income from Oil and Gas, the Brookings Institution, 1963, pg. 65.

[33] In the likely event that oil and gas are both produced from a given tract the taxpayer can convert gas production into oil equivalents and compute the depletion deduction on that basis.

the lease over its remaining life as determined by the actual production profile of each lease including the estimated future production through the shutdown year. This ratio is in turn multiplied by the remaining capitalized basis of the property to determine the cost depletion allowed in the current period. The "remaining capitalized basis" is the initial capitalized value of the bonus payment and the pre-lease exploration costs less prior depletion deductions. If the basis has previously been depleted to zero, then no cost depletion is allowed.[34] This formulation of cost depletion has been in use since 1954. It is important to note that a firm which uses cost depletion one year, may use percentage depletion in future years if percentage depletion provides a larger deduction.

Percentage depletion is an alternative method for calculating the depletion deduction. The computation of percentage depletion is as follows:

Gross income[35] from each lease is multiplied by a given

---

[34] Our estimate of cost depletion will differ from the computation made by each lessee who is permitted to revise estimates of the total quantity of recoverable reserves annually as information about the geological structure becomes known. It is not clear whether lessees have consistently under- or over-estimated the ultimate reserves from OCS leases in determining cost depletion deductions. To the extent that they have underestimated such reserves, their early cost depletion deductions will exceed those arrived at by our formula.

[35] Gross income for depletion purposes does not include royalty payments and bonus amortization. The royalty owner is allowed depletion on the royalty. When a bonus has been paid to acquire a lease, the lessee excludes from gross income a pro rata portion of the bonus paid. This is referred to as "bonus exhaustion" or "return of bonus." Since the

percentage depletion rate yielding the percentage depletion deduction subject to an upper limit which is computed as a percentage of the net income from the lease. Net income is defined as gross income less all costs attributable to the lease except depletion. The limitation on percentage depletion was 50% of net income until 1975. Since 1975 the limitation has been 65% of net income.

The percentage depletion allowance is calculated for each lease individually. If percentage depletion, rather than cost depletion, is claimed, the basis of the capitalized bonus and pre-lease exploration cost is reduced by the amount of the percentage depletion allowance. Note that the sum of percentage depletion deductions over the life of a productive lease may (and usually will) exceed the initial capital investment. This feature distinguishes percentage depletion from cost depletion and ordinary depreciation which are limited to the initial value of the investment. Beginning in 1970, the tax advantages of percentage depletion were reduced by the minimum tax as explained below. Detailed provisions of the percentage depletion allowance are summarized in Table 3.

---

lessor is allowed percentage depletion upon the cash bonus as it is received, such bonus is deducted from gross income received by the lessee, otherwise double percentage depletion deductions would result.

[36] The "quantity limitation" imposes a limit on the amount of percentage depletion that can be claimed by each eligible company. Alternatively percentage depletion can be taken on a limited quantity of natural gas production. The

Table 3. Provisions of the Percentage Depletion Allowance

Year	% of Gross Income	% of Net Income Limitation	Quantity Limitation (bbl/day)[36]	Allowed For Integrated Companies
1954-1969	27.5%	50%	none	yes
1970-1974	22%	50%	none	yes
1975	22%	65%	2,000	no
1976	22%	65%	1,800	no
1977	22%	65%	1,600	no
1978	22%	65%	1,400	no
1979	22%	65%	1,200	no
1980	22%	65%	1,000	no
1981	20%	65%	1,000	no
1982	18%	65%	1,000	no
1983	16%	65%	1,000	no
1984-after	15%	65%	1,000	no

By way of example, the percentage depletion deduction in 1958 was 27.5% of the gross income from a property, but could not exceed 50% of the net income from the property. Quantity limitations on the depletion allowance came into effect in 1975 and have been lowered to 1,000 barrels per day by 1980.

In years in which the "50% of net income" limitation on percentage depletion was binding, OCS lessees might have avoided the constraint by entering into a transaction called a "carve-out." A lessee could create a carve-out by selling rights to an amount of next year's (or another future year's) production. This had the effect of increasing current income without increasing current costs allowing the firm to claim additional depletion in a year for which the "50% of net" rule was otherwise limiting. The tax benefits

depletable gas quantity in cubic feet per day is the depletable oil quantity multiplied by 6,000.

of the "carve-out" were eliminated by the Tax Reform Act of 1969. Our analysis ignores the possibility of carve-outs and may thus overstate the tax liability of OCS lessees who utilized this method of tax avoidance.

Expensing of Intangible Drilling Costs.

Drilling costs are divisible into two categories. The first category, intangible costs, are expensed as they are incurred.

> (They) include costs of labor, fuel, power, materials, supplies, tool rental, and repair of drilling equipment. They typically account for about 75% of the costs of drilling productive wells. The remaining costs of drilling such wells, called tangible drilling costs, include expenditures for pipe, pumps, tanks and other equipment. The latter must be recovered through depreciation allowances.[37]

Intangible drilling costs receive preferential tax treatment since they are not capitalized and depreciated as is the case with like costs in other industries. By expensing intangible costs, the firm reduces its taxable income in earlier years, but must forego the depreciation deductions it would have received in later years if such costs had been capitalized. As a consequence the tax liability of the firm is partially deferred. This results in a net discounted benefit to the firm. It is estimated that 50% of total OCS

---

[37] Stephen L. McDonald, "Taxation System and Market Distortion" in Energy Supply and Government Policy edited by Robert J. Kalter and William A. Vogely, Cornell University Press, 1976, pg. 29.

drilling costs are expensed. This estimate is less than that of McDonald (as quoted above) reflecting the fact that offshore production requires the erection of costly platforms which result in a larger portion of tangible costs than would be observed for onshore production.

Depreciation of Tangible Drilling Costs

The remaining 50% of drilling costs, (the tangible portion) must be capitalized. These costs are recovered by the firm through depreciation. The tax treatment of tangible drilling costs does not differ from the tax treatment of tangible assets in other industries.

Since 1954, depreciation guidelines have been liberalized. In particular, the period of time over which an asset can be fully depreciated, referred to as an asset's useful life, has been shortened. We assume that capitalized assets used on the OCS are depreciated over a 12 year useful life using the double declining balance method of accelerated depreciation.

A 12 year useful life is within the range of allowable depreciation periods for equipment used in Marine Contract Construction (asset guideline class 15.2). This category includes oil platforms and support vessels. Such equipment can be depreciated in as few as 9.5 years or in as many as 14.5 years. An alternative depreciation category (asset guideline class 13.2) includes oil and gas exploration equipment. Equipment used for offshore exploration other than tha platform and support vessels falls into this category. Such equipment can be depreciated in as few as 11 years or as many as 17 years. A 12 year useful life is the mean value for marine contract equipment and is in the lower end of the range for other equipment.

We further assume that lessees will depreciate tangible assets in a fashion which yields the largest discounted benefit. Thus we adopt the double declining balance method of depreciation (which amounts to depreciating the asset at twice the straight line rate).[38]

The estimated depreciation deduction is computed in the following fashion:

Drilling costs in each year are divided into two categories, tangible costs and intangible costs. The intangible portion is treated as a current expense. The tangible portion is added to a capital account. One-sixth (twice the straight line rate of one-twelfth) of of the remaining undepreciated investment balance is taken each year as depreciation.

The salvage value of capital assets is offset against abandonment costs in our regular IRR formulation. If any

---

[38] Depending on the discount rate used by the firm and the useful life of the asset, the sum of years digits method of accelerated depreciation may yield a larger net benefit than the double declining balance method. The discounted benefit from either method is likely to be similar. The double declining balance method, being easier to compute, is used here.

amount remains in the depreciation account at the time of abandonment, it is written off in that year.

Expensing of Dry Hole Costs

If no oil or gas is discovered on a lease, the lessee is entitled to deduct all costs that have been incurred up to the time of abandonment. This tax treatment of unsuccessful ventures provides a substantial tax advantage to the oil and gas industry relative to other industries.

> A normal business acquires a $1 million asset generally by paying out $1 million and treating this as an addition to its capital account, which it recovers through depreciation. An oil company might typically acquire a $1 million asset in the form of a productive well worth $1 million by spending $100,000 on each of 10 exploratory wells, 9 of which are unsuccessful. The application of the general tax rule of allowing current deduction of the cost of unsuccessful ventures results in permitting oil companies to deduct immediately $900,000 which for the normal business would have been spread over the life of the asset.[39]

In the long run, productive wells must be sufficiently profitable to yield not less than a normal rate of return on all exploration and well drilling investments. Allowing the firm to expense dry holes has the effect of leaving productive fields undercapitalized in terms of tax treatment.

---

[39] Gerard M. Brannon, "Existing Tax Differentials and Subsidies Relating to the Energy Industry," in Studies in Energy Tax Policy edited by Brannon, Ballinger Publishing Co., 1975, pg. 9.

The Windfall Profits Tax of 1980

Economic profit is the difference between the total revenue collected by a firm and the private opportunity cost that the firm incurs in production. The newly enacted "windfall profits tax" is not a levy on economic profit in that it makes no reference to costs of production.[40] The windfall profits tax is in fact an excise tax on crude oil.

The "windfall profit" on each barrel of oil is defined as the actual sale price of the oil less state severance taxes (subject to limitations) and a legislated base price. The approximate initial base price of OCS oil produced in the quarter beginning March 1, 1980 is $12.81.[41] The base price is escalated quarterly based on the percentage change in the GNP deflator from the second quarter of 1979. The adjustment process is lagged two quarters. The windfall tax on each barrel of oil is a fixed percentage of the windfall profit attributable to that barrel. The tax is limited to 90% of the net income attributable to each barrel of oil. Net income is defined similarly, but not identically, to the net income associated with the computation of percentage depletion. Percentage depletion[42], the expensing of

---

[40] Except when the "90% of net rule" is binding.

[41] The base price of tier one oil (applicable to the OCS) is the May 1979 upper tier ceiling price as set by the Department of Energy regulations less $0.21. The $12.81 figure given above is the average base price of tier 1 oil as estimated in Prentice Hall Inc., "A Concise Explanation of the Crude Oil Windfall Profit Tax Act of 1980."

[42] An artificial depletion deduction is allowed in determining the 90% of net income limitation. The allowed deduction is the amount of cost depletion that would have been

intangible drilling costs and the windfall profit tax are <u>not</u> deducted from gross revenue in calculating the "90% of net income" limitation of the windfall profits tax.

The windfall tax rate is contingent on the type of producer and the type of oil. Large integrated producers are subject to a higher tax rate, <u>ceteris paribus</u>, than smaller independent producers. Independent producers are those producers which still qualify for percentage depletion. Tier 1 oil (defined as oil that is produced from property which began production prior to 1979) is taxed at a higher rate than stripper oil (referred to in the legislation as tier 2 oil) or newly discovered or heavy oil (called tier 3 oil). The windfall profits tax rates by type of producer and by type of oil are found in table 4.

Table 4. Windfall Profits Tax Rates

Type of Oil	Type of Producer Integrated	Independent [43]
Tier 1	70%	50%
Tier 2	60%	30%
Tier 3	30%	30%

For our purposes, all OCS oil production is classified as tier 1 oil. There are no state severance taxes on OCS oil and gas.

The windfall profits tax is deductible in determining taxable income for the purpose of computing the corporate

---

allowed if intangible drilling costs had been capitalized and cost depletion used for the entire life of the lease.

[43] The lower rate for independent producers applies only to the first 1,000 barrels of daily production.

tax.

The windfall tax is scheduled to be phased out when $227.3 billion dollars in tax revenue has been collected; however; the beginning of the phase out will not be earlier than January 1988, or later than January 1991. When the phase out begins, the tax liability of each producer will be reduced by 3 per cent per month for 33 months. We assume that the phase out will commence in January 1991. For computational purposes we further assume that production from each lease is identical for each month within a given year. In this way the phase out of the windfall profits tax can be accomplished by taking a weighted average of the tax forgiveness in each month. The amount of the tax that would have been paid in 1991 is reduced by 19.5% to reflect the month by month phase out. Similarly the tax in 1992 is reduced by 55.5% and the tax in 1993 is reduced by 90.25%. By 1994, we assume the windfall profits tax will be eliminated.

Firms faced with a phased elimination of a tax may adjust their production profile toward the future to avoid the tax. The extent of this behavior is unknown. Our estimates of the windfall profits tax is not modified to account for this potential behavior.

Investment Tax Credit

The investment tax credit was first initiated during the Kennedy Administration in 1962. It provides a credit against the corporate tax liability equal to a percentage of qualified investments made by the firm. The allowed credit rate depends upon the type of investment.

We assume that all tangible assets used on the OCS are new and have a useful life in excess of seven years. The total cost of such assets is thus deemed "qualified investment." The maximum credit rate is allowed for assets so classified.

The investment credit has had a volatile history since 1962. The provisions of the investment credit are described in Table 5.

To compute the limitation on the investment credit, the total financial situation of each firm must be known. We assume that each firm has sufficient tax liability so that the upper limit of the investment credit is not binding. We further assume that in any given year the amount of investment made each day is the same. Thus the investment credit rate for any given year is the allowed percentage credit for that year multiplied by the fraction of the days in that

Table 5. Provisions of the Investment Tax Credit

Time Period	Credit Rate	Credit Limit
1954-1961	-	-
January 1, 1962- October 9, 1966	7%	$25,000 + 25% of tax liability over $25,000
October 10, 1966- March 9, 1967	suspended	-
March 10, 1967- April 18, 1969	7%	$25,000 + 50% of tax liability over $25,000
April 19,1969- August 15, 1971	repealed	-
August 16, 1971- January 21, 1975	7%	$25,000 + 50% of tax liability over $25,000
January 22, 1975- December 31, 1978	10% 10%	$25,000 + 50% of tax liability over $25,000
January 1, 1979- December 31, 1979	10%	$25,000 + 60% of tax liability over $25,000
January 1, 1980- December 31, 1980	10%	$25,000 + 70% of tax liability over $25,000
January 1, 1981- December 31 1981	10%	$25,000 + 80% of tax liability over $25,000
January 1, 1982- after	10%	$25,000 + 90% of tax liability over $25,000

year for which the credit is in effect. These percentages are given in the Table 6.

Table 6. Percentage of Investment Taken as Credit

Year	% of Investment
1954-1961	0%
1962-1965	7%
1966	5.41%
1967	5.70%
1968	7%
1969	1.88%
1970	0%
1971	2.65%
1972-1974	7%
1975	9.82%
1976-after	10%

Capital Gains

A capital gain is the excess value realized from the sale of property over its adjusted basis. Capital gains are considered long term if the property is held more than one year prior to sale and short term otherwise.[13] Short term capital gains are treated as ordinary income (and are therefore taxed at the marginal tax rate discussed above.) Long term capital gains, however, generally receive preferential tax treatment.[14]

While the capital gains treatment of oil and gas properties does not differ from that of other industries, the interaction of special tax provisions afforded the industry with the capital gains statutes makes these statutes more valuable to oil and gas producers than to other businesses.

As noted above, the expensing of intangible drilling costs allows the firm to defer income taxes to future years.

> For example, a firm that has been growing rapidly in the past, drilling increasing numbers of wells and charging off most of their cost as operating expense, may find its further growth possibilities reduced and its prospective income tax liability sharply increased because of smaller prospective deductions for capital consumption. It can avoid a "catch-up" of deferred income tax liability by selling out and taking capital gains treatment on the

---

[13] Prior to 1977, capital gains on property held 6 months or more were considered long term. For tax years beginning in 1977, property held at least 9 months prior to sale resulted in long term capital gains.

[14] A capital gain realized on depreciated equipment is treated as ordinary income and therefore receives no tax preference.

proceeds.[15]

The interaction of the tax treatment of capital gains with the tax treatment of intangible drilling costs allows the firm to not only defer taxable income, but also to "convert" ordinary income to long term capital gains which are taxed at a lower rate.

The tax treatment of capital gains has also reduced the impact of the effective elimination of the percentage depletion allowance for OCS firms. Prior to 1975, OCS firms were entitled to the percentage depletion deduction. The advantage of the percentage depletion deduction is that it allows productive resource owners deductions in excess of initial capital costs. Since 1975 only the cost depletion method of computing the depletion deduction has been retained. For many productive leases this has been of little value since the cost basis of the lease properties has already been eliminated by prior percentage depletion deductions. Firms may be able to increase their present net worth by selling the mineral rights to productive properties with no remaining basis since buyers can use the purchase price as the basis for future cost depletion.

Although we recognize the possibility that tax advantages might be gained by transfer of OCS leases, we assume

---

[15] Stephen L. McDonald, Federal Income Tax Treatment of Income from Oil and Gas, the Brookings Institution, 1963, pg. 93.

that once a firm acquires a lease property, it retains the property throughout its productive life. To the extent that OCS leases change hands as firms take advantage of the tax treatment of capital gains, our estimates of OCS tax liabilities will be too high, and consequently our estimated after-tax rates of return too low.

Minimum Tax

Since 1970, corporate taxpayers have been required to pay an additional tax on a base comprised of items which receive preferential tax treatment. For OCS production, the relevant preference items are percentage depletion and long term capital gains. In our analysis, the latter item does not increase estimated tax liabilities due to the assumption that lease properties have not changed hands during their productive lives. However, in a year in which percentage depletion is claimed, the difference between the percentage depletion taken and the cost depletion that would have been allowed otherwise is considered preference income and is added to the minimum tax base.

From 1970 through 1974 the minimum tax was calculated as 10% of the adjusted minimum tax base. The adjusted base is composed of the tax preference items listed above less (a) $30,000 and (b) the tax liability of the taxpayer, plus (c) the investment credit claimed by the taxpayer. In 1975 the tax rate was increased to 15%. Since 1976 the 15% tax rate has been retained but the tax base has been modified. The tax base is now comprised of the tax preference items less the greater of $10,000 or the regular tax liability.

To account for the impact of the minimum tax on the tax liability of OCS firms, we adopt Brannon's estimate that in its first year (1970) the minimum tax had the net effect of reducing the statutory percentage depletion rate by 2%.[16] The minimum tax need only be considered from 1970 through 1974. Thus to approximate the impact of the minimum tax the percentage depletion rate is reduced from 22% to 20% from 1970 to 1974. After that time, OCS lessee firms are no longer able to utilize percentage depletion and will therefore have no preference tax base.

<u>State Taxes</u>

OCS oil and gas production does not come under the taxing jurisdiction of any state and therefore is not subject to state severence taxes. Nevertheless, additional income generated by OCS activities may generate additional state tax liabilities under unitary state tax formulas. Unitary formulas are used by many states to determine the portion of world-wide corporate income of a multistate business that is taxable by the state. While unitary formulas vary from one state to another they characteristically contain provisions

[16] Brannon, Op. Cit., pg. 5.

for apportionment of world-wide corporate income based on the number of employees working in the state, the amount of property held in the state, and the value of sales in the state.

As an illustration, consider a major oil company that operates an OCS lease in the Gulf of Mexico and also engages in business activity in the State of California. A portion of the firm's income from the OCS would be taxed by California under the state's unitary tax formula.

The marginal state tax rate varies from company to company within a state (depending on each company's payroll, property and sales in the state). Similarly a given company will face different marginal tax rates in different states (depending upon the statutes of each state).

To estimate the impact of state unitary taxes requires state by state financial information on each OCS firm. We lack the data needed to estimate state unitary taxes directly; thus, the effect of these taxes is accommodated by adding 2% to the federal corporate tax rate each year. This estimate is based upon the experience of major oil companies having operations in unitary tax states. It includes allowance for the deduction of state tax obligations from federal taxes.

Summary

In the previous sections, the tax treatment of OCS oil and gas has been outlined. For the purpose of determining the after-tax rate of return on OCS leases, the tax liability generated by each lease will be estimated. Table 7 summarizes our interpretation of relevant tax statutes.

Effective tax rates, tax credit rates and percentage depletion rates used in this study are summarized in Table 8. Effective rates may vary from statutory rates because of the interaction of several tax principles. For example, the minimum tax is accommodated by adjusting the percentage depletion rate, while the income tax surcharge and state corporate taxes are handled by adjusting the corporate tax rate. If a tax or credit is in effect for only a portion of

Table 7. Tax Treatment of OCS Oil and Gas Lease Costs[17]

Type of Cost	Tax Treatment
1) Bonus and pre-lease exploration costs	1) capitalized
a) lease proves productive	a) recovered through depletion
b) lease proves unproductive	b) charged off as loss on surrender of lease
2) Lease rentals	2) expensed as incurred
3) Dry hole costs	3) expensed as incurred
4) Intangible costs of productive wells	4) expensed as incurred
5) Tangible equipment on productive wells	5) capitalized and recovered through depreciation
6) Royalties	6) expensed as incurred
7) Production costs	7) expensed as incurred
8) Abandonment costs	8) expensed as incurred

[17] Derived from Stephen L. McDonald, Op. Cit., pg. 17.

a year, the effective rate is determined by multiplying the statutory rate by the percentage of days in the year the rate was in effect. This method is used for both the investment tax credit and the windfall profits tax.

Table 8. Effective Tax, Credit and Deduction Rates from 1954

Year	Effective Corporate Tax Rate	Effective % Depletion Rate	Effective Investment Tax Credit Rate	Effective Windfall Profi Tax Rate
1954-1961	54%	27.5%	-	-
1962-1963	54%	27.5%	7%	-
1964	52%	27.5%	7%	-
1965	50%	27.5%	7%	-
1966	50%	27.5%	5.41%	-
1967	50%	27.5%	5.70%	-
1968	54.8%	27.5%	7%	-
1969	54.8%	27.5%	1.88%	-
1970	51.2%	20%	-	-
1971	50%	20%	2.65%	-
1972-1974	50%	20%	7%	-
1975	50%	-	9.82%	-
1976-1978	50%	-	10%	-
1979	48%	-	10%	-
1980	48%	-	10%	58.68%
1981-1990	48%	-	10%	70%
1991	48%	-	10%	56.35%
1992	48%	-	10%	31.15%
1993	48%	-	10%	6.83%
1994-	48%	-	10%	-

References to Appendix 1

Agria, Susan R. "Special Tax Treatment of Mineral Industries." In Arnold C. Harberger and Martin J. Baily, (Ed.), The Taxation of Income from Capital. Washington D.C.: The Brookings Institute, 1969.

Arthur Anderson and Company. Oil and Gas Federal Income Tax Manual. Eighth edition, 1960.

Brannon, Gerard M. Energy Taxes and Subsidies. Cambridge, Mass.: Ballinger Publishing Co., 1974.

Brannon, Gerard M. "Existing Tax Differentials and Subsidies Relating to the Energy Industries." In Gerard M. Brannon, (Ed.), Studies in Energy Tax Policy. Cambridge, Mass.: Ballinger Publishing Co., 1975.

Commerce Clearing House. Federal Tax Guide. Chicago, updated continuously.

Commerce Clearing House. "Explanation of the Crude Oil Windfall Profit Tax Act of 1980." Federal Tax Guide Reports, No. 27, Vol. 63. Chicago: Commerce Clearing House, 4/4/80.

McDonald, Stephen L. Federal Tax Treatment of Income from Oil and Gas. Washington D.C.: the Brookings Institute, 1963.

McDonald, Stephen L. "Taxation System and Market Distortion." In Robert J. Kalter and William A. Vogely, (Ed.), Energy Supply and Government Policy. Ithaca, New York: Cornell University Press, 1976.

McDonald, Stephen L. "Tax Policy Toward the Petroleum Industry." In I. James Pikl, Jr., (Ed.), Public Policy and the Future of the Petroleum Industry. Laramie, Wyoming: University of Wyoming, December 1970.

Miller, Kenneth G. Oil and Gas Federal Income Taxation, third edition. Chicago: Commerce Clearing House, 1957.

Prentice-Hall Inc. "Depreciation, the Investment Creditand Your Business." Prentice-Hall Federal Taxes, Report Bulletin 11, Volume LX, Section 2. New Jersey: Prentice-Hall Inc., March 15, 1979.

Prentice-Hall Inc. "A Concise Explanation of the Crude Oil Windfall Profit Tax Act of 1980." Prentice-Hall Federal Taxes, Report Bulletin 17, Volume LXI, Section 2. New Jersey: Prentice-Hall Inc., April 2, 1980.

Prentice-Hall Inc. _Prentice-Hall Federal Taxes 1980_. New Jersey: Prentice-Hall Inc., 1980.

United States of America. Department of Energy. _Crude Oil Market Prices_. Energy Information Administration, Annual Report to Congress, 1979, Vol. 3. Washington D.C.: U.S. Government Printing Office.

United States of America. Internal Revenue Service. _Statement of Income. Corporate Income Tax Returns_. Publication no. 16. Washington D.C.: U.S. Government Printing Office, 1954 to 1976 editions.

APPENDIX 2

Changes in Data and Algorithms For Computing Before Tax Internal Rates of Return

The data and algorithms which were used in our earlier study were explained in Appendices 1, 2, 3 and 4 of our March 1, 1980 report to the USGS. Since then we have (1) added one more year of production data and two more years of drilling data and (2) made a few revisions in our computer algorithm. We do not feel that the changes that have been made justify a complete revision and restatement of the data and algorithms that have been used. Instead we will highlight below the changes that have been made.

1. Changes in the Data Base

The raw data used in this study are from the LPR-24 computer tape. Relative to the LPR-19D computer tape, which was used in our earlier study, LPR-24 contains one additional year of production and royalty data (through 1979), three more years of well drilling data (through 1979) and a few minor corrections of erroneous entries.

In the computational procedure we chose to delete the 1979 drilling data on the grounds that wells drilled in that year would generally have no impact on production in 1979. Inclusion of 1979 wells would overstate costs since the takeoff point for future projections is the level of production of revenue achieved in 1979.

A small number of wells in the data base had no spud dates attached to them. For some of these wells, the completion record indicates that the wells had actually been drilled while for others the completion record indicates that the wells were only planned. For computational purposes we treated wells with no spud dates as having been drilled in the last year in which any wells were drilled on the lease.

Since two more years of well drilling data were added, we had to update our estimates of the costs of drilling and equipping wells and the cost of equipment beyond the Christmas tree. Furthermore, more recent estimates of cost indices have been made available since our last report. Therefore we updated our estimates of future operating and abandonment cost. A list of cost elements that have been updated and the cost index used is found in Table 1.

2. Changes in Computational Algorithms

In our earlier report we based our crude oil price scenario on President Carter's 1979 proposal for phased crude oil price decontrol, coupled with a windfall profits tax on various classes of oil. Since the completion of that report, the windfall profits tax has been enacted into law. As enacted, the law it contains substantial revisions from the original Carter proposal. The actual provisions of the law as enacted are incorporated in our present analysis. The windfall profits tax is applied to the difference

Table 1. Cost Estimates Which Have Been Updated

Cost Element	Years	Procedure Used in Updating
Cost of Drilling Equipping Wells	1977-1978	Estimates taken from Joint Association Survey of the U.S. Oil and Gas Producing Industry. American Petroleum Institute, Washington D.C., 1977-1978.
Cost of Equipment Beyond the Christmas Tree	1977-1978	Multiply 1976 entry by Producers Price Index for Durable Goods, 1977-1978.
Operating Costs	1980-2010	Multiply 1979 entry by the forecasted index of hourly wage rates 1980-2010 (Source- Data Resources Inc., Long Term Review, Summer 1980).
Abandonment Costs	1980-2010	Same as for Operating Costs.

between the actual selling price of crude oil and a base price which is set by federal regulations. The tax rate depends on the type of producer and the type of oil produced (see Appendix 1). For the purposes of this study the relevant tax rate is 70 percent of the windfall tax base. All production from 1954-1969 leases is classified as old oil and all lessees are large companies, according to tax definitions. The windfall tax became effective in 1980 and is scheduled to begin phase-out not earlier than 1988 nor later than 1991. The phase-out will take approximately three years. In our analysis we conservatively assume that the phase-out will commence in 1991 and will be completed by the end of 1993.

Since present crude oil price controls are scheduled to expire on September 30, 1981, our price scenario allows lease specific oil prices to escalate to the world price in 1982. The net future price of crude oil to the producer is determined by subtracting the per barrel windfall tax from the world market price as given by the following equation.

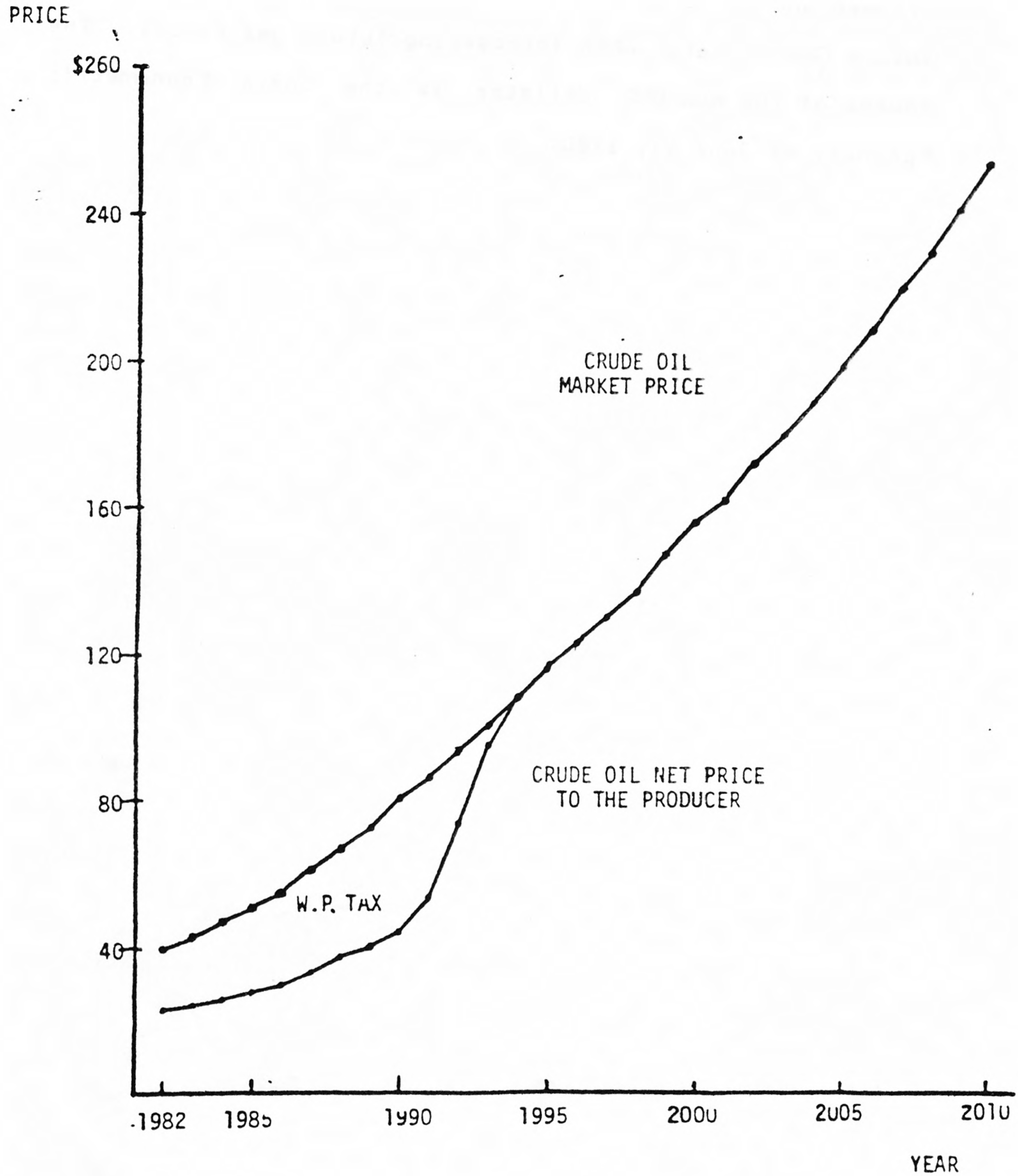
$$P_p = MP - [(MP - BP) \times .70]$$

where

Pp = price of crude oil to the producer
MP = market price of crude oil
BP = base price of crude oil

The crude oil price forecast, base price and windfall tax base are shown in Figure 1. The future price forecast for crude oil is derived from the Department of Energy's 1979 Report to Congress (see the References to Appendix 1).

The gas price scenario is unchanged from our earlier report except that (1) one more year of production is allowed and (2) that we use an updated forecast of the future GNP deflator when forecasting future gas prices. The source of the new GNP deflator is the Chase Econometric Forecast of June 11, 1980.



SOURCES: See Appendix 1.

allowed and (2) that we use an updated forecast of the future GNP deflator when forecasting future gas prices. The source of the new GNP deflator is the Chase Econometric Forecast of June 11, 1980.

JRSI
1985