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OF THE

U.S. HOUSE OF REPRESENTATIVES

AND

COMMITTEE ON FINANCE

OF THE

U.S. SENATE

MARCH 11, 1969

PART 4

NOTE: This document has not been considered by either the Committee on Ways and Means of the House of Representatives or the Committee on Finance of the Senate. As indicated in the letters of Chairman Mills and Chairman Long, the document is being printed for information purposes only so as to make it generally available.

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John M. Martin, Esquire
The Chief Counsel
Committee on Ways and Means
House of Representatives
Washington, D. C. 20515

March 11, 1969

Dear Mr. Martin:

Pursuant to the request of Chairman Wilbur D. Mills, Committee on Ways and Means, I am enclosing herewith three copies of a report, dated December 27, 1968, entitled "The Economic Factors Affecting the Level of Domestic Petroleum Reserves," prepared by CONSAD Research Corporation for the Office of Tax Analysis of the Treasury Department.

We understand that this report will be published as Part 4 of the Committee Print of the "Tax Reform Studies and Proposals," which were developed by the Treasury Department during the administration of President Johnson.

This report, which has not been reviewed by this Administration, is forwarded without comment.

Sincerely yours,

Charls E. Walker

Charls E. Walker

GP

THE ECONOMIC FACTORS AFFECTING THE LEVEL OF DOMESTIC PETROLEUM RESERVES

Prepared for:

Office of Tax Analysis
U.S. Treasury Department
Washington, D.C.

Prepared by:

CONSAD Research Corporation
5600 Forward Avenue
Pittsburgh, Pennsylvania 15217

December 27, 1968

PREFACE

This is the final report of a study of the potential effects of changes in the special Federal tax provisions relating to the oil and gas industry on the level of domestic petroleum reserves. The study was performed under U.S. Treasury Contract No. TAS68-8.

The final report was prepared by Dr. Robert Byrne, Project Director, and Dr. Robert Karg. Other CONSAD personnel contributing to the study include Dr. Jacqueline Anderson, Mrs. Sally Strieter, Mr. Luke Sparvero, Mr. David Marshall, and Mr. Dennis Green. Dr. Wilbur Steger served as Program Director.

Dr. Dale Jorgenson, of the University of California at Berkeley, Mr. Simon M. Simon of New York University, Dr. Robert Lucas of Carnegie-Mellon University, and Mr. Arthur Wright of Yale University, served as consultants during the study.

Numerous contributions were made by Treasury Department personnel during the progress of the study, in particular, by Dr. Gerard Brannon, Dr. Richard Pollock, and Dr. Seymour Fiekowsky.

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I. STATEMENT OF THE PROBLEM

Special Federal tax provisions which, in effect, favor the oil and gas industry have been supported partly on the grounds that they provide the extra economic incentives required to stimulate the exploration and development of domestic petroleum reserves. In this study, the question under investigation is whether a change in special Federal tax provisions concerning the oil and gas industry would have a substantial effect on the level of known domestic petroleum reserves (through changes in the level of expenditures for expenditure and development).

The special tax provisions in question are:

1. Percentage depletion, a standard deduction of 27.5% of gross income from oil and gas production, which results in a reduced effective tax rate for the industry.

2. The option to deduct as current expense certain exploration and development costs which, by most criteria, would be considered investment in capital assets and would, therefore, be subject to gradual depreciation. This results in a deferred tax liability.

To answer the questions posed, the study investigated the interactions among three components:

1. The size and nature of the petroleum reserves,

2. The structure and operation of the petroleum industry, and

3. The special Federal tax provisions affecting the industry.

Although much had been written about each of these elements individually, little study based on empirical evidence of the relationships among them had previously been undertaken. Thus, much of the instant research was devoted to establishing the links and relationships between the major components and the elements within the components themselves.

It is recognized that the effects of a change in the tax laws would not be limited to changes in reserves, since producers might react in a variety of ways. The study was aimed at determining the reserve change which might occur if producers reacted to the change solely by modifying their reserve holdings, which provides an estimate of the maximum reserve impact.

II. CONCLUSIONS

The study develops numerical estimates of the changes in liquid hydrocarbon and natural gas reserves which would occur if the percentage depletion allowance were reduced (or eliminated) and if the option to expense intangible drilling costs were removed, and the resultant tax increase was absorbed by the petroleum producers.

It seems clear that reduction of the percentage depletion allowance or elimination of the option to expense intangible drilling costs will tend to result in a reduction in reserves. It is more meaningful, however, to compare the magnitude of the reserve decrease with the tax loss required to avoid it. Such a comparison may indicate that there are less costly methods for achieving the objective of maintaining desired levels of reserves.

Although it is evident that the available data concerning the level of reserves, as well as data on various economic factors, such as finding cost, are such that a perfect prediction of the effects of changes is not possible, the approach taken in the study was to develop as good a numerical prediction as possible and thus provide a base point for consideration of the further effects of changes in tax policy.

The study was limited to estimating the effects of tax changes on reserve levels under the assumption that any resultant tax increase was

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absorbed by petroleum producers and not passed forward to consumers or backward to landowners.

The major conclusions of this study are:

1. The elimination of percentage depletion as an option would reduce existing reserve levels by 3% and result in an additional $1.2 billion in tax revenue at current production levels.

2. Elimination of the option to expense intangible drilling cost would reduce existing reserve levels by from 1.9% to 4.0%, depending on the alternative tax policy.

3. Percentage depletion is a relatively inefficient method of encouraging exploration and the resultant discovery of new domestic reserves of liquid petroleum. This is in part due to the low sensitivity of desired reserve levels to the price subsidy represented by percentage depletion, and in part to the inefficiency of the allowance for this purpose, since over 40% of it is paid for foreign production and non-operating interests in domestic production.

These estimates represent what might be expected if producers were unable to shift the tax increase resulting from the indicated tax law changes, i.e., if the increased taxes were paid entirely out of after-tax profits. They thus represent maximum, or "worst case" impacts, since there are a number of other ways in which producers might react to these tax changes, all of which would lessen the effect of the changes on the profitability of holding reserves and, consequently, on reserve stocks. That is, if the net increase in tax payments by the producers of domestic crude and natural gas can be passed on to consumers, or be compensated for by a reduction of costs, then the effect on reserve stocks will be smaller than that estimated in this study. In actuality, the probable result of such tax changes will be a combination of all possible effects discussed here.

As such, care should be taken in analyzing the possible impacts of tax changes one at a time. Quantitative estimates of such impacts are almost certain to be in excess of actual impacts.

The most obvious of these methods of reducing the impact of tax changes is the sale of reserves as capital assets. In such a case, the difference between sale price and discovery cost would be taxed at capital gains reates, and the new owner would obtain a cost basis approximately equal to true value to be recovered through cost depletion deductions.* In this manner, the difference between the actual cost of discovery and the discovery gain under present tax policy would be taxed at a maximum 25% (capital gains) rate, rather than at the 48% (or higher) rate which would otherwise prevail if percentage depletion were eliminated. The lack of data on the discovery value of deposits makes it impossible to determine the extent to which this method might be used

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*Deductions based on the actual cost of obtaining reserves. For a detailed explanation, see Section V. B.

in the event of elimination of percentage provisions. As a rough estimate, however, one might expect the sale of reserves as capital assets to reduce the increase in tax revenues to about one-half the projected amount and, similarly, to halve the percentage change in reserves.

There are two methods by which producers might, in reaction to changes in tax policy, effectively shift to others the total burden of paying the additional taxes. One would be to shift the burden forward by increasing prices to ultimate consumers of petroleum and natural gas products. The other would be to shift the burden backward by reducing the royalties paid to landowners. To the extent that either or both of these occurred, the economic effect of the tax changes on the producers would be reduced, as would be the consequent effect on reserves.

Davidson* has presented a case for the backward shift, based primarily on the weaker bargaining position of royalty owners. Various industry sources indicate that the forward shift will take place,** perhaps in an effort to enlist public support of the present tax laws.

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*Davidson, P., "Public Policy Problems of the Domestic Crude Oil Industry," American Economic Review, 53, March, 1963, pp. 85-108.

**E.g., Minor Jameson, Executive Vice-President of the Independent Petroleum Association of America, news service interview, September 11, 1968.

The industry might also react by attempting to reduce direct costs, for example, by shutting down excess wells in overdeveloped fields.* There is considerable evidence that substantial cost reductions could be made by this method,** and the impact of a substantial increase in tax payments may be sufficient to overcome some of the resistance to cost cutting. Another possible reaction might be an attempt by the integrated major producers to recoup the tax increase from other parts of their operations, such as refining. This is a possibility owing to the large share of production controlled by these firms. The economic power of these firms may be great enough to enable them to force independent producers to bear the burden of the increased taxes, by reducing field prices and thus increasing the profitability of refining operations.

In assessing the desirability of any specific tax change, one relevant question is whether the economy as a whole benefits from the change, even though certain groups may be adversely affected. This question was not specifically addressed in this study. However, the investigations reviewed during the course of the study were in substantial agreement

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*Such attempts have been made, see, e.g., Oil and Gas Journal, August 22, September 26, and December 5, 1962.

**See, e.g., Oil and Gas Journal, June 21, 1965, p. 100, and Journal of Petroleum Technology, 10, 1958, p. 12.

that the current situation was one of economic inefficiency, and that any changes were almost certain to be beneficial to the economy in the long run.

Another important consideration in evaluating these estimates is the accuracy of the economic models used to explain past changes in reserves (and then to project future changes as the result of modification of tax policies). The existence of a significant relationship between changes in reserves and technological changes in oil production, as has been suggested,* would effect the accuracy of models explaining reserve behavior in economic terms. Data on well productivity** shows that, in the period from 1948 to 1965, the average capacity of non-stripper wells*** has risen from 35 barrels per day to 55 barrels per day, or 57% over the 17-year period.

This large increase in well productivity, when combined with a fairly stable value of average-proved reserves per well, implies that

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*U.S. Department of the Interior, United States Petroleum Through 1980, Washington, D.C., Government Printing Office, July, 1968.

**Ibid., p. 30.

***A stripper ' a well which is unable to produce more than ten barrels of oil a da. Non-stripper wells provide over 90% of United States production.

the reserves needed to support a given level of production on a technological basis have declined by 36% since the period 1944 to 1948, four years during which crude oil capacity and production were virtually identical. The economic significance of this point is stated in a Department of the Interior report:

> "In view of this fact, it no longer appears necessary to maintain a ratio of proved reserves to production in the vicinity of 12 to 1 to insure the producibility of reserves at required rates. Since there are substantial costs attached to creating and maintaining inventories, whether above or below ground, it might be expected that operators would avail themselves of opportunities to reduce the portion of their assets so invested, and this appears to be occurring. Proved reserves of crude oil have been stable at around 31 billion barrels since 1959, while production has risen by 22%. As a result, the ratio between reserves and production has declined slowly from 12.7 to 10.4. This follows by several years a similar reduction in the proportion of above ground crude oil inventories to production, made possible by increased efficiency and capacity in transportation and processing facilities, including the important contribution of Lease Automatic Custody Transfer to the reduction of lease storage requirements. In 1930 there was a five months' supply of crude oil held in tanks and pipelines. By 1940 the stock had decreased to 74 days. By 1950 this figure had dropped to 42, and in 1966 the above ground crude inventory averaged 28 days' production."*

If this analysis is correct, the reserve ratio should be expected to drop further even if there is no change in tax policy or other economic factors.

---

*United States Petroleum Through 1980, ibid., p. 31.

There are three major reasons for holding reserves:

1) To support (technologically) the anticipated production requirements,

2) To provide a buffer stock in the event of unanticipated increases in demand,

3) Because of substantial profits accruing to discoverers of reserves.

The last of these is the only one which is greatly affected by the relative profitability of production, and the results of this study support the conclusion that (1) is the major reason for holding reserves.

It should be noted that if it is desired to increase reserves from their present levels, increasing the profitability of petroleum production will be a very inefficient way to accomplish this objective. Some method of direct payment for the "service" of holding reserves (similar in concept to stockpiling of strategic materials) would be a much more efficient approach.

III. STUDY METHODOLOGY

The overall study approach was to be as empirical and as quantitative as was possible within the limitations imposed by the data. The emphasis was on determining what relationships apparently existed between the relevant economic factors and the level of reserves in order to project the effects of certain changes in tax policies.

In approaching a project of this scope, there are several alternative study methodologies from which to choose. The number of alternative approaches which merited exploration is here larger than might normally be encountered because of a lack of generally accepted theory. This lack in turn results partly, but not entirely, from the lack of sufficient data to support conclusively or refute any of several currently proposed theories. Consequently, three different approaches were utilized in this study. Each approach has its good and bad points, and the idea in utilizing three different ones was to determine whether all three would be mutually supportive. To the extent that they are, of course, we may feel more comfortable about the conclusions reached.

A. Neoclassical Economic Approach

The first approach used was the calibration of models based on neoclassical economic theory, in which reserves are treated as a capital stock and the level of reserves is taken to be a function of price of output, interest rate, finding cost, and production level. The historical values of these variables were used to determine the relative effect of each in determining observed levels of reserves under the assumption that the industry reserve totals reflected the effects of the economic variables in competitive markets. Based on a priori reasoning, the effects of possible changes in tax policy on these basic causal variables were then estimated, and from the altered values of the variables new levels of reserves were projected.

This approach assumes that the observed values of variables are those existing under a close approximation of economic equilibrium and, consequently, that the projected levels of reserves represent those which would exist after the industry had made a full adjustment to the tax change. Since some of the possible tax policy changes evaluated are of greater magnitude than any observed past changes, it may well be that the adjustment of the industry to changes of this magnitude may not be completed for a period of years.

This approach was unsuccessful in estimating changes in natural gas reserves, at least in part due to the fact that the historically observed reserve values do not represent a state of equilibrium.

B. Behavioral Approach

The second approach utilized was to construct a more behaviorally oriented model in which a series of time-dependent relationships between a number of possibly relevant variables (such as gross income, numbers of wells drilled, barrels of reserves discovered, and expenditures for exploration and development) are derived, based on a combination of economic theory and empirical data. The model itself, then, is a constructed logical relationship among these variables (in this case reserves) given the values of the input variables (in this case production, price of crude, and percentage depletion rate).

C. Individual-Producer Approach

The third approach used was to develop a model of an individual crude oil producer and refiner. This model was based on empirical relationships as to the results of exploration and development activity and the assumption of rational economic behavior on the part of the operator. Since very few data on the activities of individual firms were available, many of the relationships in the model were based on estimates.

The objective of this model was not to predict the actual changes in reserve levels which would result from a change in certain tax policies but, rather, to examine how an individual firm might react to a change in tax policy and then to observe whether this reaction was consistent with the predicted aggregate behavior of all firms. For instance, if the aggregate prediction of the result of a specific tax change were a 10% decrease in reserves, one would not expect each individual firm in the industry to decrease its reserves by 10%. Rather, some firms might not decrease reserves at all, while others might decrease them quite drastically. If, however, the firm model were to predict that an individual firm would substantially increase its reserves, this would be <u>inconsistent</u> with the conclusion of the aggregate model and indicate the need for further analysis. The idea behind the firm model, then, is more to provide clearer <u>understanding</u> of reserve changes than to project the actual changes in reserve levels which would occur.

Another feature of this model is that it is dynamic. It reflects the decisions made by the firm over time; and, consequently, it can be used to estimate the pattern in which firms will modify reserve levels as the industry moves toward a new equilibrium point in reaction to a tax policy change.

D. Data

This study was hampered (as are most quantitative studies) by lack of data in many areas. For example, the petroleum industry is a heterogeneous group of firms which range from large, integrated companies (which explore, develop, produce, refine, transport, and market all the final products, both domestically and abroad) to special-interest operators who perform only one aspect of the total process. In addition, there are non-operating interests which provide capital and accept risks but do not bear operating expense. Each type of firm would be affected in different ways by changes in the tax provisions; and, ideally, a model of the industry would allow for the changing mix of operators and their differing responses.

E. Summary

The results of the economic model and the individual producer were mutually supportive. The industry simulation model could not be developed.

The numerical values generated by the neoclassical economic model are the projected impacts. The effects of the micro-model require some interpretation. The impacts must be determined by comparing the simulated behavior of the firm under current tax policies with those under alternative policies. Under current policies, the indicated behavior is a small increase in development activity and a concomitant decrease in reserves over the ten year simulation period. This is not surprising, as it coincides with the observed behavior of the industry during recent years. The impacts of tax changes then are evaluated on a comparative basis with this result.

IV. THE INDUSTRY, OIL AND GAS RESERVES, AND THE TAX PROVISIONS

The answer to the question of whether a change in the special Federal tax provisions would affect the level of domestic petroleum reserves can be answered only through understanding of the context within which the question is embedded, namely, the special tax provisions, the structure of the petroleum industry, and the size and nature of the domestic petroleum reserves.

This section presents the background which is directly relevant to the problem under investigation. First, the structure of industry is described, indicating the various kinds of firms which comprise the industry and the activities that are undertaken. Next, a quantitative description of the amount and nature of petroleum reserves is given, including a comparison of alternative measures. Finally, the present special Federal tax provisions are discussed and the various options available to the industry are outlined.

A. Industry Structure

The industry which finds, develops, and produces crude petroleum in the United States is composed of a heterogeneous group of firms which cannot be completely separated from the industry which refines, transports, and markets domestic petroleum, nor from the industry which finds, develops, and produces foreign crude oil.

The petroleum industry has a number of fairly distinct functional stages. Any particular firm may be engaged in one or more of these stages; some firms are engaged in all. For background purposes, these stages may be though of as:

<u>Predrilling</u>: These activities include geological-geophysical surveys to determine areas of potential production, acquisition of leases, and location of promising drilling sites.

<u>Exploratory drilling</u>: This is undertaken to find new occurrences of oil or gas. Wildcat wells are drilled outside existing fields: approximately 10% are successful. Other exploratory wells are drilled in fields where oil or gas has been found, in a search for new pools. The success rate is higher, around 20%.*

<u>Development drilling</u>: This is undertaken in the area of a successful exploratory well to determine the nature and extent of the deposit, and to provide appropriate productive capacity. When fully

*See Table A.19.

developed, the producing area is covered with producing wells and ringed with dry holes.

Production: This is the process of getting oil up to the well-head. The chief costs of production are labor and repair costs.

Transportation and refining: This stage prepares the crude oil for the market in many different forms.

The study limits its attention to determining a quantitative picture of activities which occur in the first four stages, namely, predrilling, exploratory and development drilling, and production.

The oil and gas producing industry accounts for about 1.5% of the Gross National Product of the United States. By most conventional standards, it is not a highly concentrated industry, but with so enorm-our an output, each of the largest firms is a giant in the economy. The five top domestic producers together account for 20% of output, the top 20 for 50%. Thousands of smaller operators make up the rest of the industry; many of them work under contract or a farm-out arrangement with the larger firms or are partially subsidized by them by means of so-called "dry hole" or "bottom hole" contributions -- payments for geological information.

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The industry is hedged about with regulations and special provisions. The regulations are mainly imposed by agencies within each state, set up to prevent overproduction and wasteful dissipation of gas pressure which may be caused when many competing producers try to take oil from a field too quickly. The state agencies have effectively become price-fixing agencies, as they operate by restricting production to "market demand" to prevent oil from lying unsold on the market. The method of operation of the regulations has induced a large over-capacity in the industry. Both Texas and Louisiana could, for example, increase production by 1-1.5 million barrels daily (daily United States production is about 7 million barrels), and total excess capacity stands at approximately 40%.

At the same time, the United States is a net importer of foreign oil, which is considerably cheaper, even after transportation. The quantity is restricted to 12.2% of domestic demand, a restriction imposed in 1959 on national security grounds.

The industry also benefits from special tax provisions, which are the subject of this report and those are discussed in detail in Section IV.C and Chapter V.

Demand for crude oil, which had increased rapidly since the beginning of the century, began to level off after 1958 and at the present time is rising at a slow rate. However, productive capacity has continued to rise and since 1958 has outstripped production at an increasing rate.*

Demand for natural gas has, however, increased very rapidly (Table 4.1), and stood at more than three times the 1946 figure in 1965, while domestic crude oil production had only increased by 50%. The leasing of offshore properties in 1962 opened the prospect of new sources of oil and gas.

Profit rates or rates of return are, at best, difficult to measure and must be viewed with caution. Figure A.1 (derived from Table A.17) shows alternative patterns of profit rates computed by various economists for the petroleum industry; other industries are shown as a comparison. These rates all indicate to a greater or lesser extent that the profit rate declined until approximately 1958. The rate then began a slight upward trend. (Alternative profit rates for the domestic crude oil industry, which will be presented later, suggest that the upward movement has continued.)

As far as can be determined from the data, the decline in profits has affected the smaller operators and particularly the smaller explorers.

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*See Figure A.3.

TABLE 4.1
U.S. DOMESTIC PROVED RESERVES AND PRODUCTION

YEAR	CRUDE OIL ONLY: Production during year	Proved reserve end of year	Ratio Production/Reserve	NATURAL GAS LIQUIDS: Production During year	Proved reserves end of year	Ratio Production/Reserve	NATURAL GAS: Production During year	Proved Reserve end of year	Ratio Production/Reserve
	(1) Million bbls	(2) Million bbls	(3)	(4) Million bbls	(5) Million bbls	(6)	(7) Billion cu.ft	(8) Billion cu.ft	(9)
1946	1726	20,874	12.1	(This detail not available for 1946)			4,916	159,704	32.5
1947	1850	21,433	11.6	161	3254	20.2	5,599	165,026	29.5
1948	2002	23,280	11.6	184	3541	19.3	5,975	172,925	28.9
1949	1819	24,649	13.5	199	3729	18.7	6,211	179,402	28.9
1950	1944	25,268	13.0	227	4263	18.8	6,855	184,585	26.9
1951	2214	27,468	12.4	267	4725	17.7	7,924	192,759	24.3
1952	2256	27,961	12.4	285	4997	17.6	8,593	198,632	23.1
1953	2312	28,945	12.5	303	5438	17.9	9,183	210,299	22.9
1954	2257	29,561	13.6	301	5244	17.5	9,375	210,561	22.4
1955	2419	30,012	12.5	320	5439	17.0	10,063	222,483	22.1
1956	2552	30,435	11.9	346	5902	17.1	10,849	236,483	21.8
1957	2559	30,300	11.9	352	5687	16.1	11,440	245,230	21.4
1958	2373	30,536	14.9	312	6201	18.2	11,423	252,762	22.1
1959	2483	31,719	12.3	335	6522	14.9	12,373	261,170	21.1
1960	2471	31,613	12.3	431	6815	15.8	13,019	262,326	20.2
1961	2512	31,759	12.6	462	7049	15.3	13,377	266,274	19.9
1962	2550	31,389	12.5	470	7312	15.6	13,638	272,279	20.0
1963	2593	30,970	11.9	516	7674	14.8	14,546	276,151	19.0
1964	2644	30,991	11.7	536	7747	14.5	15,347	281,251	18.3
1965	2686	31,352	11.7	555	8024	14.5	16,252	286,469	17.6

Source: Proved reserves of Crude Oil, Natural Gas liquids and Natural Gas., Dec. 31, 1965. Vol 20. American Petroleum Institute

This can be seen from the pattern of drilling.* The number of wells being drilled reached a peak in 1955-56 but has since declined steadily back to its 1949 level, over 30% below the peak. Exploratory wells have followed the same pattern: 16,000 were drilled in 1956 and 10,700 in 1964. The wildcat boom produced 918 new fields in 1955; 701 were found in 1965. This has been taken by some to show that exploration is dangerously declining.

Fewer wells are being drilled now than formerly, but the average depth of exploratory wells has increased steadily from 4,560 in 1953 to 5,164 in 1964. The number of wells in the middle levels has declined, but the number of wells over 15,000 feet increased by more than 700% in that period (Figure 4.1). The total number of feet drilled has declined far less than the number of wells, and has recently begun to show an upward trend.

As the average depth of wells has increased, there has been a marked increase in the importance of the larger companies in exploration activity; this is presumably derived from the fact that exploration has become a costlier business and smaller companies cannot compete. The marginal cost of an explorational foot increases greatly with depth.**

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*See Table A.19.
**See Figure 4.2.

FIGURE 4.1

RELATIVE CHANGE IN DRILLING AND COSTS, BY DEPTH
U.S. DOMESTIC INDUSTRY
1953; 1963

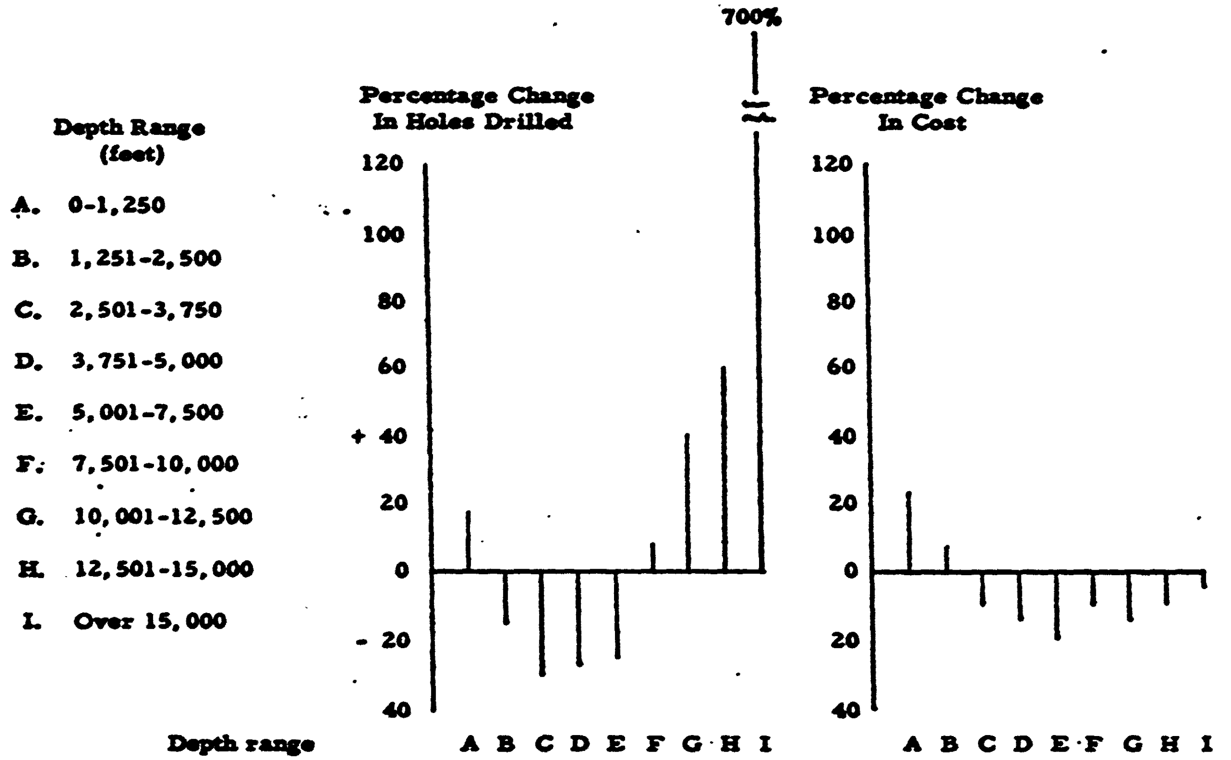
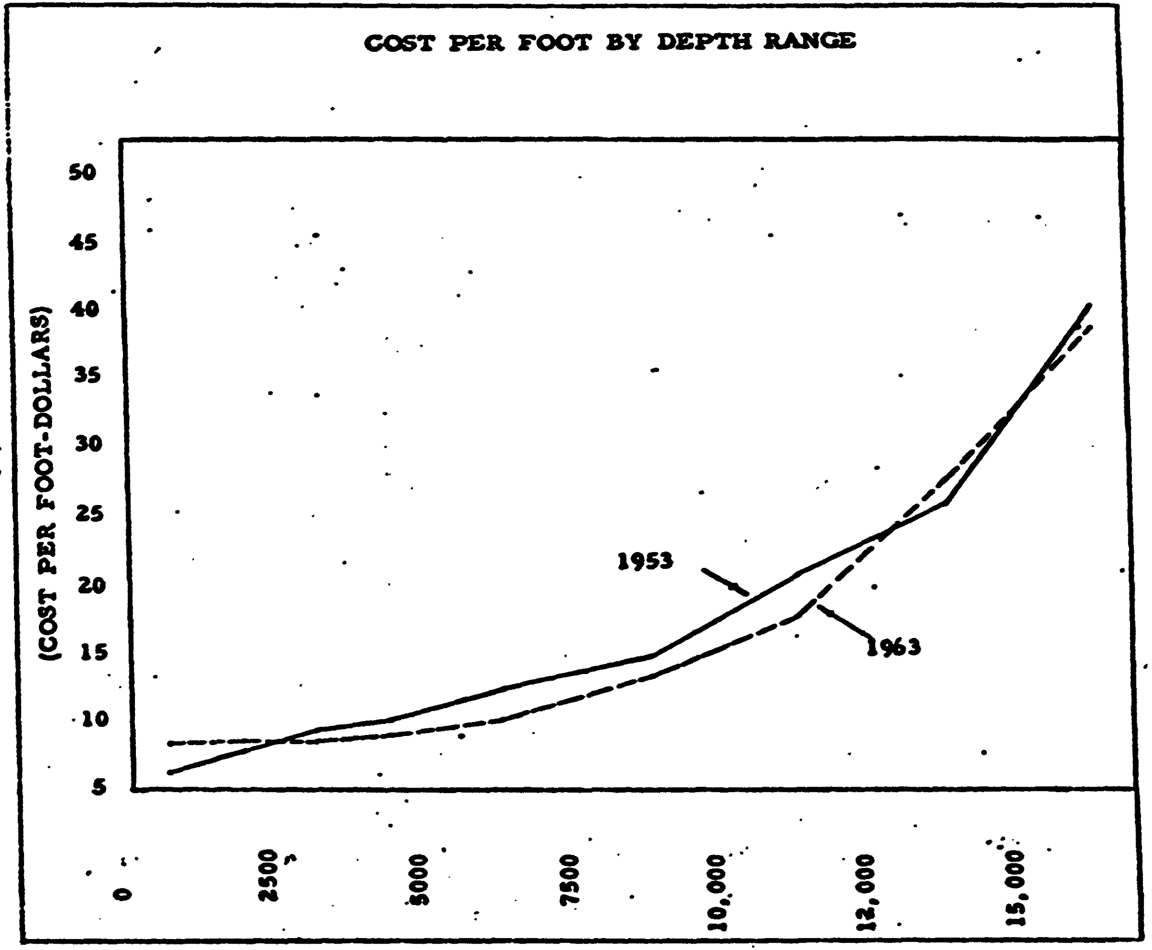


FIGURE 4.2


COST PER FOOT BY DEPTH RANGE
(COST PER FOOT-DOLLARS)
50
45
40
35
30
25
20
15
10
5
0
2500
5000
7500
10,000
12,000
15,000
1953
1963

A 15,000-foot well costs over four times as much as three 5,000-foot wells. Although the average-per-foot cost has remained stable, the pattern of expenditures has moved heavily toward the deeper wells (see Table A.22).

This accounts for the fact that the 30 large companies covered by the Chase Manhattan Bank's surveys now spend more than 68% of all domestic exploration and development outlays, a proportion which has increased from 52% in 1956.* The payment of large bonuses to the Federal government in off-shore exploration has also contributed to this. At the same time, 65 companies, ranked by the number of wells they drill, can only account for 30% of the total wells drilled.** This indicates that the larger companies are drilling deeper wells and thus spending more per well, a point confirmed by the Census of Mineral Industries for 1963, which shows that the first 200 companies drill an average of more than 70% deeper than other companies. The smaller companies also drill very few wells per company, since the 65th-ranking company (by wells drilled) is drilling only 18 wells, while there are more than 3,000 companies engaged in drilling activities.***

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*See Table A.1.
**See Table A.23.
***See Tables A.28 and A.29.

The apparent shift of exploratory activity from small to large firms is probably accentuated by technology, for the larger companies benefit first from technological developments, since they are able to afford a more extensive predrilling program and also more research into drilling and recovery methods. This shift of exploratory activity to larger companies is supported by the fact that, while the total number of wells drilled declined by 11.6% between 1961 and 1965, the wells drilled by larger companies declined only by 8%, and those drilled by smaller companies by 12.9%.*

The smaller companies are spending considerably less on exploration and development in absolute terms. At the same time, their share of the production is diminishing, but at a much slower rate. This could be the result of their being bought out by larger firms or going out of business; either reaping capital gains on past expenditures or simply producing what reserves they have previously discovered.

Typically, the larger companies also have substantial interests abroad: The largest domestic producer produces four times as much abroad as at home. Although foreign operators cannot import more than a limited amount to the United States market, the faster growing European and Asian markets provide an outlet for United States producers

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*See Tables A.29 and A.30.

and make foreign investment increasingly attractive. There has been a marked shift to foreign production since 1961,* with almost all large producing companies increasing the percentage of their total production derived from foreign fields.

B. Reserves

There is little agreement as to the size of reserves. In the first place, different attempts to measure reserves have used different definitions, but even where the same definition is used, estimates differ by as much as 50%.

Reserves, it must be emphasized, are that part of the original oil in place in the crust of the earth which are expected to be recoverable under a given set of economic and technical conditions. Definitions vary in their tolerance of uncertainty and their assumptions about the progress of technology.

The American Petroleum Institute (API), in a series of estimates beginning in 1946, confines itself to virtual certainty of recovery. Although the estimates represent, as the authors stress, "a strictly technical judgment, not knowingly influenced by policies of conservatism

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*See Table A. 28.

or optimism," the definition of reserves is limited to "the volumes of crude oil which geological and engineering information indicate beyond reasonable doubt to be recoverable in the future from an oil reservoir under existing economic and operating conditions." These crude oil estimates do not include oil which may become available by known methods of extraction, such as fluid injection, which have not yet been applied to particular fields, nor do they include natural gas liquids, shale oil or other substitute sources. It must, therefore, be regarded as a minimum estimate.

There are, as the API warns, additional amounts of oil which will eventually be recovered from known fields, which informed men "know" to exist. Table 4.2 gives the API estimates divided into new reserves from exploration and new reserves from development which shows that development of fields yields 5 to 6 times the reserves originally estimated for a field. It seems virtually certain that the present estimate of reserves in known fields will be revised substantially over the course of their development.

The National Petroleum Council (NPC) published in 1965 a series of data* which allocates crude oil discoveries back to the year of original

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*Proved Discoveries and Productive Capacity, National Petroleum Council, Washington, D.C., 1965.

TABLE 4.2
U.S. DOMESTIC CRUDE OIL RESERVES AND DISCOVERIES

Year	New reserves from exploration NRE (1)	New reserves from development NRD (2)	New reserves attributed to year of discovery (3)	Ratio 1964 estimate/original (4)	Moving three year average (5)	Ratio NRD/NRE
	Million barrels	million barrels	million barrels	(3) ÷ (1)		(2) ÷ (1)
1943			1462[b]			
1944			2064			
1945			1922			
1946	244[a]	2414[a]	1537	6.30		9.89
1947	445	2019	1163	2.61	5.67	4.54
1948	396	3399	3207	8.10	4.59	8.53
1949	890	2297	2725	3.06	5.04	2.58
1950	564	1998	2237	3.97	3.44	3.54
1951	389	4025	1280	3.30	3.46	1.03
1952	496	2253	1540	3.10	3.11	4.54
1953	592	2704	1727	2.92	2.94	4.57
1954	586	2287	1641	2.80	2.75	3.90
1955	477	2394	1212	2.54	2.52	5.02
1956	467	2507	1038	2.22	2.60	5.37
1957	416	2009	1260	3.03	2.55	4.83
1958	315	2294	758	2.41		7.28
1959	369	3297				8.93
1960	254	2111				8.31
1961	361	2296				6.36
1962	381	1800				4.72
1963	350	1824				5.21
1964	346	2318				6.70
					average	5.57

Notes, Table

Sources: Cols (1) and (2) Proved Reserves of Crude Oil, Natural Gas liquids and Natural Gas Vol. 20. p.15 API
Col (3) National Petroleum Council Proved Discoveries and Productive Capacity (1965), Table I

[a]No comparable data available for earlier years.

[b]These figures are estimated from 1964. This series represents a temporal reallocation of cumulative proved reserves in Col(2).

discovery of the field; the series represents in the main a temporal re-allocation of the cumulative proved reserves as estimated by the API. The NPC series ends at 1958, so that the latter year had six years development history, while the older fields had considerably more.

By comparing the estimates made by the API in the year of discovery with the reallocations made in the NPC series, it is possible to derive a picture of how the estimate of reserves increases over the development history of the average well.

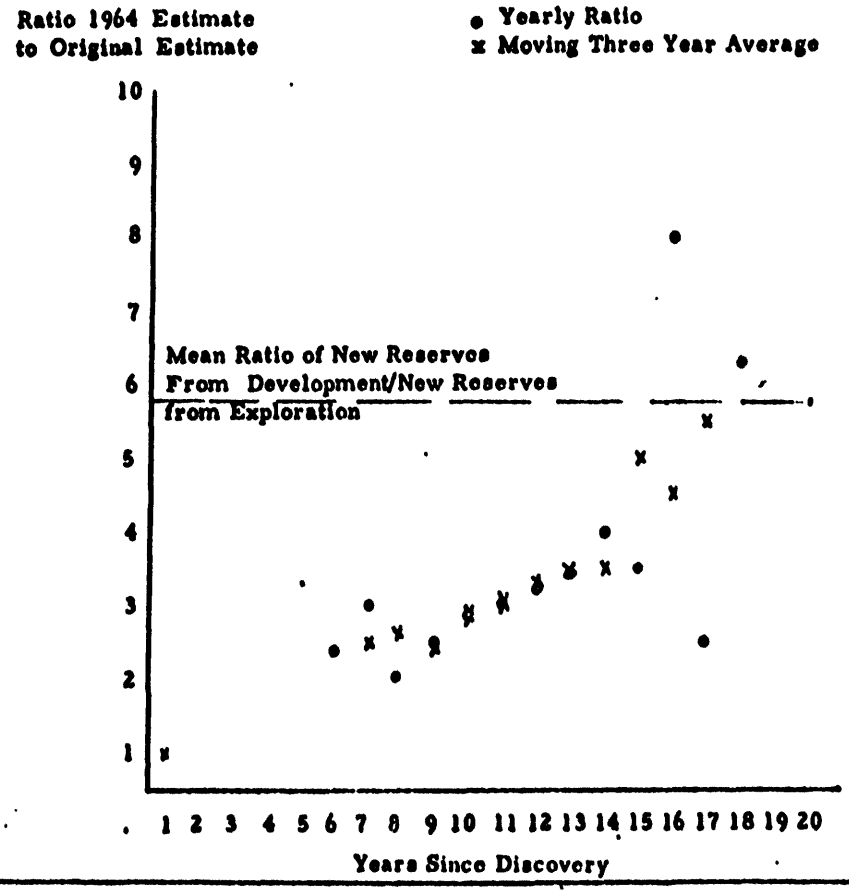
Table 4.2 shows the ratio of reserves estimated at year of discovery with reserves attributed to that year, estimated between 6 and 17 years later. This can also be seen in Figure 4.3. There is a steady upward progression of estimates which show little sign of a decline. In fact, comparison with the mean value of the ratio of new reserves from discoveries and new reserves from extensions and revisions (NRE/NRD) over the period suggests that after 17 years estimates have only reached half their eventual level. There is no indication of any trend which would suggest that over time initial discoveries are less likely to be supplemented by future extensions and revisions.

1. Interstate Oil Compact Commission Data

Five reports by the Interstate Oil Compact Commission (IOCC), issued at two-year intervals between 1954 and 1962, make estimates

FIGURE 4.3

INCREASE OF ESTIMATES OF RESERVES BY YEARS SINCE DISCOVERY OF FIELD



of oil reserves under differing probability assumptions.

The concepts used are:

1. Primary reserves, which specifically do not include secondary recovery methods,

2. Estimated additional recovery by conventional fluid injection methods under economic recovery conditions,

3. Estimated reserves physically recoverable by known methods,

4. Original oil content of known reservoirs.

In definition, it is concepts 1 and 2 taken together which correspond most nearly to the API definition of proved reserves. Comparative figures for January 1, 1962 are:

API Proved Reserves		31.8 billion barrels
IOCC (1) Primary Reserves	31.4	
(2)	16.3	
(1) + (2)		49.7 billion barrels
(3)		40.2 billion barrels
(4)		346.2 billion barrels

The API estimate of total proved reserves is very similar to the IOCC estimate of total primary reserves. In detail, the estimates by states are not so closely related, and the author of the IOCC report disclaims the similarity as accidental. The two sources are working under differing definitions and comparison of the two definitions most closely related in the two sources shows that the IOCC estimate is higher by some 50% while addition of the physically recoverable reserves increases the IOCC estimate to more than three times the size of the API.

Concept 4 is interesting since it is the only available estimate of oil originally in place in known fields. By adding cumulative production to date with potential production by known methods which are economical, a recovery ratio can be derived, giving an indication of the current state of technology of oil recovery.

Cumulative production to 1962	67.8 billion barrels
Primary reserves	31.4 billion barrels
Secondary reserves	16.3 billion barrels
Crude oil eventually recoverable under existing economic and technological conditions	115.5 billion barrels
Oil originally in place in known fields	346.2 billion barrels
Recovery rate	32.8%

A recovery rate of 33% is low by comparison with other mineral industries, but there are confident predictions by engineers within the industry that this could be doubled, by using known methods of secondary recovery. This would then double recoverable reserves from known fields without further exploration.

2. "Ultimate Reserves"

The size of "ultimate reserves" is only of incidental concern to this study. If the phrase is taken to mean the original resource base, the size is in no way responsive to economic or fiscal policy. If by "ultimate reserves" is meant the amount of the resource base which will eventually be recoverable, this will depend very largely on technological improvement, mentioned above. As an indication of orders of magnitude, the estimates of the resource base fluctuate about a central estimate of 500 billion barrels. At present recovery rates, this would yield about 156 billion barrels of potential reserves; under alternative estimates of the impact of technology, more would be ultimately recoverable. Of course, the discovery of these potential reserves will depend on further exploratory drilling, but the magnitude of the estimates of the resource base suggests that this study need in no way be concerned with the existence of further crude oil deposits as a limiting factor. Figure 4.4 illustrates graphically the general relationship between the actual petroleum resources in existence and that portion which are classed as reserves.

3. Alternative Sources of Crude Oil

Exploration is only one of many means of expanding potential supplies of petroleum products. It has been the main method in the

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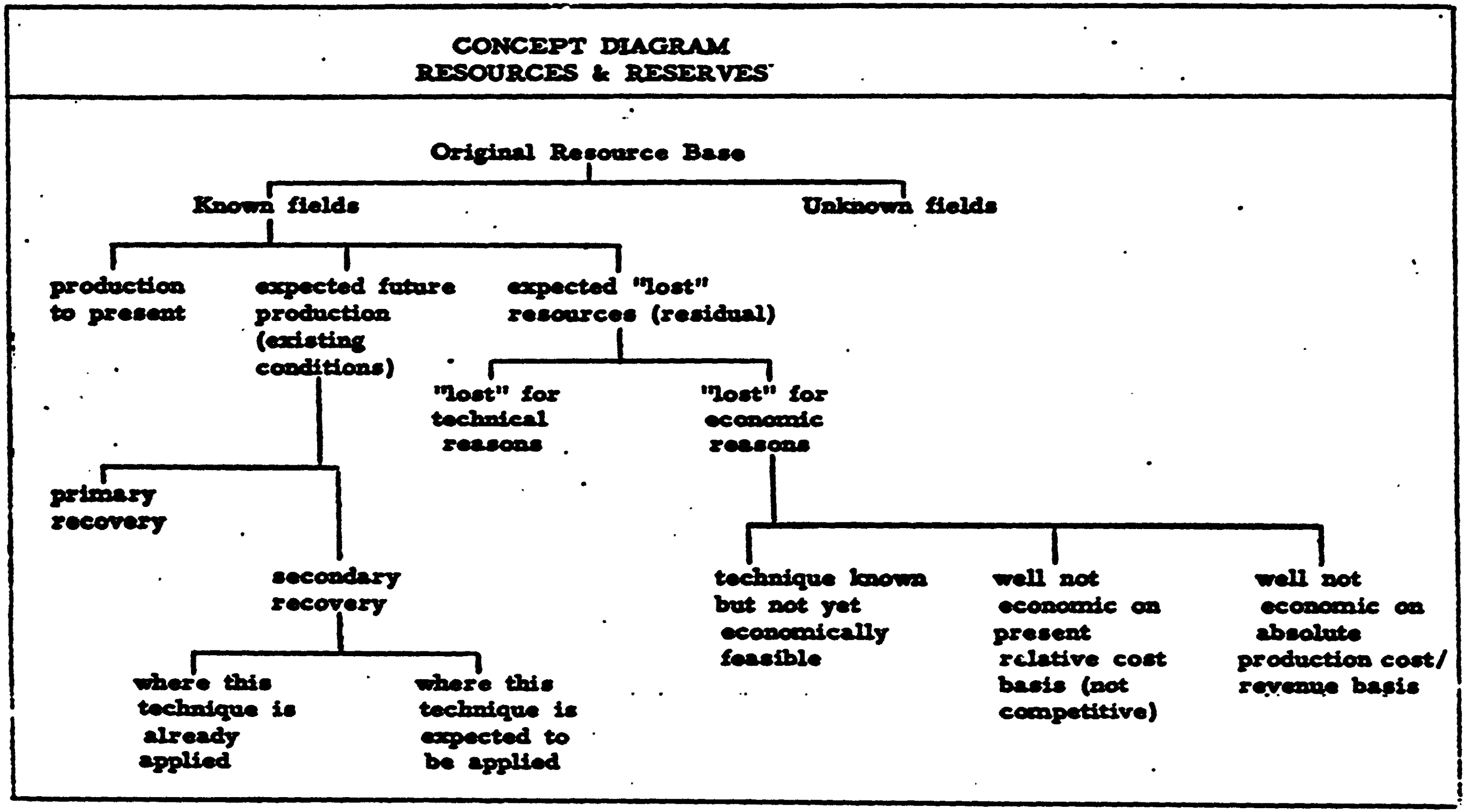
FIGURE 4.4


CONCEPT DIAGRAM
RESOURCES & RESERVES
Original Resource Base
Known fields
Unknown fields
production to present
expected future production (existing conditions)
expected "lost" resources (residual)
"lost" for technical reasons
"lost" for economic reasons
primary recovery
secondary recovery
where this technique is already applied
where this technique is expected to be applied
technique known but not yet economically feasible
well not economic on present relative cost basis (not competitive)
well not economic on absolute production cost/revenue basis

past but other methods may prove more profitable in the future.

Allied to the technical progress in recovery methods, discussed above, is potential progress in the use of crude oil in final products. Crude oil is not demanded for itself, but as a raw material for the petroleum refining industry, and more efficient use of crude oil could effectively increase the supply of petroleum products without exploration. However, large breakthroughs in this direction do not appear probable and in this analysis will not be considered in detail.

4. Natural Gas Liquids

Natural gas liquids are to some extent substitutes for crude oil, as they are used in many of the same final products. Production increased from 1/10 the level of crude oil production in 1947 to 1/5 the level in 1965. The ratio of API-estimated reserves to production fell steadily from 20 to 14 in the period. By the end of 1965, the reserves of natural gas liquids constituted a supplement of 25% to reserves of crude oil.

5. Shale Oil

It has long been known that the western states contain millions of tons of oil awaiting an economic method of extraction. It was reported on April 26, 1967, that a commercial firm had plans for beginning production of shale oil at a rate of 58,000 barrels a day by 1970.* (The current output of crude oil is approximately 7 million barrels a day.) Whether this development marks the beginning of a viable shale oil industry has yet to be seen, but if commercial production proves feasible, the oil in the shale lands would increase oil reserves at least a hundred-fold.

6. Canadian Reserves

A fourth source of oil reserves which could be utilized in the event of strategic necessity are the Canadian reserves. These have increased rapidly in recent years, the CPA estimating them at 6.7 billion barrels in 1965 (see Figure A.5). With Canadian production at 291 million barrels for 1965, proved Canadian reserves equal about 2-1/2 times the total yearly United States and Canadian production, or 22 times the yearly Canadian production.

Figure A.5 presents the time trend of the Canadian reserves/production ratio. Since Canadian crude is not subject to formal import quota restrictions, and a substantial fraction of Canadian reserves are owned by United States firms or United States controlled firms, the increase in Canadian reserves is undoubtedly attributable, at least in

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*<u>New York Times</u>, April 26, 1967.

part, to their treatment by United States firms as a direct substitute for United States domestic reserves.

7. Significance of the Reserve Level

Although it should be clear from this chapter why the API series should not be interpreted as a "reserve-life" series or an indication of "how long reserves will last," it is pertinent to inquire why the ratio of reserves to production has remained consistently in the region of 12:1. Secretary of the Interior Udal prefaced some remarks to the National Petroleum Council with the words, "If we elect to hold to the historic reserve-to-production ratio of 12:1, we will have to add 83 billion barrels to our proved reserves by 1980." What forces have been at work on the historic ratio, and why should we elect to hold to it?

The industry is not forced to keep its ratio at 12:1. That it does choose to do so can be inferred, for example, from the fact that when exploration wells reached their peak in 1956, the reserve ratio actually declined, because of the sudden increase in demand occasioned by the Suez Crisis, but the ratio of "what the industry might have extrapolated demand to be" to the end-of-year reserves shows the same ratio as previous years. It is also true that, in years when demand declined, the ratio suddenly rose. However, during the same period, the natural gas ratio has declined consistently, as has the ratio for natural gas liquids. Why does crude oil stay constant?

Crude oil and natural gas are bound together, and are generally joint products of exploration effort. Since crude oil is still the major output of the crude oil and natural gas producers, it may be assumed that crude oil reserve holdings have been the policy leaders and that, so long as reserves of the other minerals are at a satisfactory level, it is crude holdings which have been optimized. It is possible that with the increased importance of natural gas, the future may bring a shift from a policy of optimizing crude to optimizing natural gas holdings. However, in the period under review, it is assumed that the reserve/production ratio for natural gas and natural gas liquids has decreased because production of these minerals has increased relative to crude oil.

This implies that the oil and gas industry chooses to hold inventories of at least 12 years potential supply. (This figure should be taken as a minimum estimate. Companies' estimates of reserve holdings based on alternative probability assumptions must exceed those of the API.) Other industries optimize their inventory holdings under several constraints. The disadvantages to holding inventories are cost of storage, locked-up capital and the possibility of obsolescence. The relative importance of these will vary. Obsolescence is very important to the garment industry, but not to the crude oil industry. Locked-up capital is particularly important to industries which depreciate their investment over many years -- real estate firms hate to hold inventories. Oil producers are allowed to amortize their investment immediately for tax purposes, but capital is still locked-up, both in the form of sunken exploration costs and in the resulting saleable assets which could be sold. The third factor, storage costs, may appear to be negligible, for oil in the ground is not using warehouse space. However, wells require regular maintenance even when not producing.

The advantages to holding inventories are the possibility of meeting sudden increases in demand without over-much strain on productive capacity. In the case of oil, there are two elements to "productive capacity" -- lifting equipment and reserves. The true bottleneck to production is at the lifting stage, although the present 39% excess capacity is more than enough to cope with peacetime demands within historical limits.* Evidently, the industry would want to insure against a sudden forced push into exploration, but given the costs of holding inventories, it is difficult to explain why the industry should elect to hold so large a stock.

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*The increase in demand for the Korean War from 1950-1951 was 14%. The estimate of 39% excess capacity is from United States Petroleum Through 1980, U.S. Department of the Interior, p. 32. The calculations there are based on NPC estimates of productive capacity.

It may be the case that there is a Maximum Efficient Production ratio with a constant percentage decline in possible production from each well. The late A. D. Zapp suggested that it would be possible to calculate reserve figures from estimates of productive capacity using MEP and constant percentage decline concepts.* If this is the case, then the industry is bound to keep its reserve to production ratio at or above a certain level.

However, the certain level may not be 12:1. First, this ratio is almost certainly an underestimate of what companies consider their inventories to be. Second, the effect of the state regulations may lead to overdevelopment.** Overdevelopment would tend to create a spurious increase in reserves, for while it does not increase the recoverable oil in known fields, it increases the <u>certainty</u> with which the reserves are known to exist. Thus, a company may feel confident enough of an estimate of reserves in a particular field and would, if it could, extract it with a minimum of development wells. However, the API criterion of certainty is more stringent than the company's estimating procedure

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*Zapp, A.D., <u>Future Petroleum Producing Capacity of the United States</u>, U.S. Department of the Interior, Geological Survey Bulletin 1142-H, Washington, D.C., 1962.

**This is discussed in Section V.C.6.

and as new development wells are drilled in response to the low production allowables, more of the company's estimate falls into the API category. If all excess development were to fall off, the API estimate could fall to a lower reserve-to-production ratio without there having been any significant change in company estimates of known reserves.

Thus, although the API estimate shows a considerable stability over time, it is impossible to tell how far this represents a stability in "real reserves" in the sense of the real underlying content recoverable from known fields.

The data in Figure 4.3, however, strongly suggest that the initial API estimates of reserves from exploration bear a consistent relationship to later estimates of reserves "really" found. Thus, the API series is probably a reasonable proxy for what companies think their reserves are, particularly on an aggregate basis. The comparative stability of the reserve-to-production ratio suggests that the primary determinant of reserves to be held is production.

C. Present Tax Policy

The current tax provisions for the oil industry are based on the general principles of taxation of corporate income. The special provisions which result in an effectively lower tax rate for the industry arise out of the special nature of the industry and certain historical interpretations of the general tax laws.

1. General Principles of Tax Liability

In general, corporate income is subject to taxation after the costs of business have been deducted. Expenses for goods and services which are used up in the accounting period are generally deductible in that period: these include labor costs, rents, utilities, raw materials, transportation, etc., except in cases where these costs are embodied in resulting capital assets. Losses due to fire, theft, abandonment, etc., are also deductible.

Money which is spent for capital assets, such as machines and buildings, has generally to be spread over the life of the asset, or depreciated. The amount of depreciation which can be deducted from corporate income as a cost of doing business in any one year will be the fractional value of the machine which is consumed in the current year's production. However, if at any point the machine becomes obsolete, the remaining cost becomes deductible as a loss in that year. The depreciation claimed should represent the extent to which the value of the machine is reduced by use during the accounting period.

2. Effect of the Depreciation Allowance

At the present time, there are several alternative methods of spreading the deductions for capital consumption over the lifetime of the capital good. Before 1954, deductions had to be spread equally over each year of the life. In recent years, methods of calculation have been introduced which allow for higher deductions at the beginning of the goods life.

The effect of this has been to shift tax liability into the future and increase the flow of available funds to corporations. The value of alternative time pattern of tax liability is a function of the rate of interest: a dollar today is worth more than a dollar tomorrow by virtue of the fact that a dollar in the bank earns, say, 4%, while a dollar reinvested in a business can usually earn considerably more. The gain to a corporation of deferring tax liability may be considered as the present value of the extra flow of funds over the life of a capital asset discounted at some suitable rate of interest.

The difference can be computed by use of the standard formula,

$$\text{Present Value} = \frac{R_1}{(1 + r)} + \frac{R_2}{(1 + r)} + \ldots + \frac{R_n}{(1 + r)^n}$$

R is the cash flow each year and r is the discount rate, in this case, the expected return on invested capital. In the case of an asset costing C dollars, using straight line depreciation over n years, the returns R_1, R_2, etc., are equal and all equal to $\frac{C \cdot t}{n}$ where t is the tax rate.

Then the difference is discounted cash flow, which represents the extra value to the company of expensing in the current year is:*

$$\frac{C \cdot t}{1 + r} - \frac{C \cdot t}{n} \sum_{1}^{n} \frac{1}{(1 + r)^{n}}$$

Table 4.3 shows the present value of alternative methods of depreciation with a tax rate of 48%, using a rate of interest of 9% and an asset life of ten years. The alternative methods are the straight line method, the double declining balance method, and the sum-of-the-digits methods, all of which may currently be used. The alternative of expensing in the first period, although it is not generally available for capital assets, has also been included because of its relevance to the oil industry. Nine percent was chosen as a relevant rate of interest since it is the lower limit to the highest series of estimates** of post-war rates of profit in the oil industry. It can be readily seen that considerable advantage is to be gained from accelerating depreciation claims, and that the maximum advantage is gained by expensing in the first period.

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*To provide a fair comparison, assume expenditures are made at the beginning of the year and all returns accrue at the end. Thus, even an "expensed" outlay should be discounted one year for comparison purposes.

**Estimates by the First National City Bank as published in MacDonald, Stephen, Federal Tax Treatment of Income from Oil and Gas, Washington, D.C., 1963.

TABLE 4.3

COMPARISON OF EXPENSING IN CURRENT PERIOD WITH THREE METHODS OF DEPRECIATING OVER 10 YEARS

	METHOD OF WRITING-OFF ASSET			
Year	Expensing	Straight Line	Double Declining Balance	Sum of the Digits
1	1000	100	200	182
2	0	100	160	164
3	0	100	128	145
4	0	100	102	127
5	0	100	82	109
6	0	100	66	91
7	0	100	65.5[a]	73
8	0	100	65.5	55
9	0	100	65.5	36
10	0	100	65.5	18
	1000	1000	1000	1000
Present Value at 9%	917.43	641.77	708.44	726.77
Present value of tax concession at 48% tax rate	440.376	308.05	340.05	348.88

Value of expensing as opposed to most advantageous method of depreciating. = 440.366 - 348.885 per $1000 = 9.15%.

[a]Companies have the option of changing to a more advantageous method at any point; straight line depreciation becomes more profitable at 7 years.

3. Principles of Taxation Applied to the Gas and Oil Industry

In most industries, the initial value of an asset is its supply price, and depreciation is usually claimed on this initial cost. However, in oil and gas extraction, the investment which is sunk into a capital asset, i.e., the expenditures for exploration and development of an oil well, may bear little relation to the initial value of a successful well. It will be argued later in the analysis that all exploration and development expenditures should be considered as investment, which will be carried to a point where the discounted net returns which can be expected from a given exploratory outlay will equal the outlay. However, about 40% of all wells are dry, and in accordance with the principle that losses are immediately tax deductible, dry holes are expensed for tax purposes as soon as they are abandoned. This provision also applies to all geological, geophysical, lease acquisitions and other costs attributed to unsuccessful properties. If total exploration and development expenditures are considered to be the relevant cost of the capital asset, with the returns from the single successful well compensating for the expenditures on all unsuccessful wells, it can be seen that the provision for expensing dry holes is a form of highly accelerated depreciation, resting on the principle of deductibility of losses, losses being computed by single property rather than by total assets.

4. Successful Wells

The exploration expenses on successful wells are subject to various tax provisions. A substantial portion is considered as investment in a capital asset and is subject to depreciation allowances. Expenditures for tangible equipment such as pumps, tanks, and pipes are classified as tangible costs. These are attributed to a depreciable assets account and are treated exactly as depreciable assets in other industries. Geological and geophysical surveys, lease rentals and bonuses are also considered as expenses to be deducted over the productive life of the resulting asset. These, however, are kept in a separate depletable assets account, and are subject to the depletion provisions discussed below.

Costs of labor, materials, and other goods incidental to drilling are considered intangible costs of drilling and are expensed as soon as the well is discovered to be productive.* This expensing, which is claimed for a very large part of exploration costs, is to be contrasted, for example, with construction, where labor costs embodied in a capital asset have to be depreciated. The provision is a means of deferring tax liability which has evolved by administrative decision rather than by

*This may involve holding expenses undepreciated for a period of time.

Act of Congress. It is of considerable value to the industry, as can be seen in Table 4.3, where different methods of depreciating are compared with expensing.

5. Development Expenditures

When an area has been found to be productive, further drilling is undertaken. There will be further dry holes found in determining the boundary of the field, and the costs of these are expensed as they occur. The expenses on successful development wells are treated in the same way as expenditures for exploratory wells. The tangible drilling costs are cumulated and depreciated; the intangible drilling costs are expensed.

6. Production Expenditures

When a well reaches the productive stage, expenditures are treated as in other industries: current inputs consumed in use are expensed, and current inputs with an extended productive life are depreciated. A summary of all tax provisions appears in Table 4.4.

7. Depletion

The depletion provision is a tax deduction claimed by the industry for the consumption of oil and gas deposits. It is perhaps most easily understood in the light of its history. Analogous to a depreciation

TABLE 4.4

TAX ACCOUNTING TREATMENT OF EXPENDITURES IN THE FINDING, DEVELOPMENT, AND PRODUCTION OF OIL AND GAS

Expenditure	Tax Treatment
1. Dry hole costs	1. Expensed as incurred[a]
2. Lease rentals	2. Expensed as incurred
3. Lease acquisition costs	3. Capitalized upon acquisition, charged to depletable asset account.
a. Leases later proved unproductive	a. Capitalized cost charged off as loss upon surrender of lease[b]
b. Leases later proved productive	b. Capitalized cost recoverable as such only through cost depletion
4. Other exploration expense (such as geophysics, geology)	4. Capitalized if on an area of interest,[c] otherwise expensed as incurred, charged to depletable asset account.
a. Areas later proved unproductive	a. Capitalized costs charged off as a loss upon surrender of property[b]
b. Areas later proved productive	b. Capitalized cost recoverable as such only through cost depletion
5. Intangible drilling costs of producing wells	5. Option of expensing as incurred or capitalizing and recovering through cost depletion[d]
6. Tangible equipment on producing wells	6. Capitalized charged to depreciable assets account and recovered through depreciation
7. General lease equipment on producing properties	7. Capitalized charged to depreciable assets account and recovered through depreciation
8. Production costs	8. Expensed as incurred

[a]Taxpayers electing to capitalize intangible drilling costs have the additional option of either expensing or capitalizing dry hole costs. The option to capitalize intangibles is almost never used.

[b]Or upon final determination of worthlessness of mineral rights without immediate surrender of the property.

[c]An area of interest is one in which further exploratory work is at least conditionally contemplated.

[d]Capitalized intangible costs incurred in the installation of casing and equipment and in the construction on the premises of derricks and other physical structures are recoverable through depreciation.

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allowance on capital assets, the depletion allowance was intended to compensate owners of oil and gas deposits for the investment they had made resulting in profitable assets. As a manufacturer is allowed to claim tax relief over the life of the asset on an investment in a machine, so, it was claimed by the proponents of a depletion allowance, the oil prospector-taxpayer should be able to claim tax relief on his investment in oil exploration and development.

It followed then, that a depletion allowance was first introduced in March 1913, early in the history of corporate and personal taxation. Tax deductions were permitted in accordance with a formula essentially similar to depreciation, and based on the estimated value of existing wells on March 1, 1913, and thereafter on the costs of exploration and development. Thus, those people who owned wells on or before March 1, 1913 were able to claim considerably more for similar wells than those who discovered wells after this date, because the embodied costs of drilling were, in general, considerably lower than the value at discovery.

The lower allowable cost base had wider ramifications when a proposal was introduced in 1918 to tax excess profits, excess being defined as more than a reasonable rate of return on assets. Evidently, those wells with cost base computed on March 1, 1913, value had a higher asset figure to serve as denominator in rate of return calculations than those wells which were costed on embodied exploration and development expenditures, so their tax rate was correspondingly lower. Representatives of the industry argued that the rate of return should be computed on the total outlays for successful and unsuccessful wells as representing real investment on which return was earned, a view which the industry no longer holds and which the Federal government at that time rejected.*

Eventually, a second provision was introduced in 1918 allowing "discovery value depletion," by which the estimated discovery value was substituted for all wells found after March 1, 1913, as the value which was to be amortized. This was substantially greater than the total outlay figure the industry had pressed for. It was payable only to the discoverer, but it increased the annual deductions by a considerable amount, since discovery value on a successful well is many times higher than actual outlays made for that particular well. It also increased the relevant asset base for purposes of the rate of return excess profits tax.

Discovery value depletion had a brief and unfortunate history, since estimates of discovery value had continually to be revised, and

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*Hearing before the Committee on Finance, U.S. Senate, 65th Congress, 2nd Session, 1919, p. 356.

agreed upon; a tax allowance would be made on the value of production in each year, which would stand proxy for the rate of exhaustion of the deposit. Production had the virtue of being a reasonably well-attested figure, whereas a formula based on the estimated size of the deposit was subject to many errors. The depletion, which was to be allowed as a tax deduction, was a standard percentage of the gross value of mineral production, hence, the name, percentage depletion. The standard rate was decided by a compromise between the House and the Senate who could not agree on 25% or 30%. The percentage depletion rate for oil and gas has thus been 27-1/2% of gross income since 1927, unless this amount exceeds 50% of net income after certain deductions, in which case only 50% of net income may be claimed.

The depletion provisions operate at various lower rates for other minerals and for timber, which claim smaller amounts of depletion. All minerals are subject to the 50% of net income limitation.

8. Current Provisions

The oil and gas producer has basically two options in calculating his depletion allowance. He may take percentage depletion, as defined above, or he may take cost depletion which is a "true" depreciation based on actual expenditure. Depletion is calculated for each property separately or, in certain cases, on specified aggregations. In almost all cases, percentage depletion is preferred and in fact, 88% of depletion claimed is taken as percentage depletion. There is, however, a net income limitation on the amount which can be claimed.

9. Net Income Limitation

The net income limitation limits percentage depletion (but not cost depletion, where this is taken) to 50% of net income after gross income has been reduced by deductions on producing properties. Deductions for non-producing properties do not figure in this adjustment at all and are deducted separately after calculation of percentage depletion. If 27-1/2% of gross income exceeds 50% of net income, it is the latter which must be taken. It can be seen that this will occur when:

$$.5 \text{ Net Income (NI)} \leq .275 \text{ Gross Income (GIN)}$$

$$\text{Net Income (NI)} \leq .55 \text{ Gross Income (GIN)}$$

$$\text{Gross Income Less Net Income (GIN-NI)} \geq .45 \text{ Gross Income (GIN)}$$

i.e., when deductions for a producing property exceed 45% of gross income from mineral production on that property. The effect of the net income limitation will be discussed in more detail below. Approximately 15% of percentage depletion claimed is claimed under the net income limitation, rather than at the statutory rate.

There are legitimate ways to avoid the net income limitation by phasing costs so that all expensing is done in one year and the limitation is hit only once; thereafter the statutory rate may be claimed in perpetuity for the life of the well. Alternatively, a recent provision (1956) permits capitalized and accumulated intangible costs to be deferred and expensed over the five years following the discovery of the well. This may allow the net income limitation to be avoided altogether. In some cases, the aggregation of properties which are part of the "same operating unit" permits the deductions to be spread far enough to avoid the limit.

However, there are properties for which, at least in the initial phases of the production, when production is low and expenses high, deductions so far exceed 45% of gross income that the allowable percentage depletion is considerably reduced and the alternative of cost depletion is considered. This also may occur late in the production cycle when the well is no longer free flowing.

10. Cost Depletion

In principle, either cost depletion or percentage depletion, whichever is the greater, may be claimed on a property. In practice, as has been noted, percentage depletion has been claimed. However, cost depletion has been increasing in importance in recent years for reasons which will be examined later.

Cost depletion is calculated thus:

The cost base is the cost remaining in the depletable assets account, which is generally derived from the capitalized and accumulated expenditures for geological and geophysical surveys and lease acquisition. This account is adjusted downward each year by the amount of depletion actually claimed. The physical base is the estimated number recoverable units of mineral remaining in the well, which is adjusted each year for the units actually removed. The allowable cost depletion is then the adjusted cost base multiplied by the fraction of the physical base removed in a year.

$$CD = \text{Adjusted cost base} \times \frac{\text{Mineral units produced}}{\text{Mineral units remaining at beginning of year}}$$

Supposing cost depletion were claimed each year over the life of a property. Then, initial cost $\bar{C}$, initial mineral units $\bar{M}$, depletion claimed in the first year would be:

$$CD_1 = \frac{P_1 \bar{C}}{\bar{M}} \qquad \text{where } P_1 = \text{production in year 1.}$$

In the second, $CD_2 = \dfrac{P_2}{\bar{M} - P_1} \cdot \left[\bar{C} - \dfrac{P_1 \bar{C}}{\bar{M}}\right]$

$$= \frac{P_2 \bar{C}}{\bar{M}}$$

$$= CD_1 \cdot \frac{P_2}{P_1}$$

Thus, if $P_1 = P_2 = P_3 = P_4$, etc., i.e., if equal production is made from a well over its life, the provisions allow for equal deductions each year. If, as is more usual, production declines over the life of the well, cost depletion still being taken, the ratio $\frac{P_n}{P_1}$ will diminish and the allowable cost depletion will follow the declining pattern of production.

It follows, then, that the time when allowable cost depletion is likely to be highest is also the time when properties are most likely to hit the net income limitation, that is, at the beginning of the flow of oil. It is then that cost depletion may prove to be the better option. Generally, however, the percentage depletion provisions give the better option, and the depletable asset account or cost base is adjusted by depletion actually claimed.

V. EFFECTS OF SPECIAL TAX PROVISIONS

This chapter examines the justification for the special tax provisions in terms of both the magnitude of claims and incidence of benefits across both foreign and domestic operations of the various kinds of firms within the petroleum industry.

A. Justification for Special Provisions

Depletion can no longer be considered amortization of an investment. Since the percentage depletion provision was introduced, more and more exploration and development expenditures have been declared immediately tax deductible, so that only a very small investment now remains for tax purposes. As a base for cost depletion, this small remaining investment is in most cases eroded soon after production begins and percentage depletion is taken. In effect, percentage depletion is a substantial subsidy to the oil industry, one which takes the form of a reduced tax payment, based on a percentage of the dollar value of production.

The justification advanced for the retention of special tax provisions for the oil and gas industry center on the argument that for some reason the free market would not offer the domestic industry a return sufficient to enable it to continue at a level which would ensure adequate supplies of oil in time of a sudden increase in demand. Presumably, such an increase would occur in the event of war.

The argument in its simplest form runs: National security require replacement of domestic reserves. Replacement of reserves requires a high level of exploration. A high level of exploration requires a special government incentive. Specifically, a tax incentive is required. The special provisions provide the necessary tax incentive.

This study does not undertake an analysis of the reserves required by the national security. It does, however, seem pertinent to point out that, in the event of a sudden increase in demand for finished petroleum products, pipeline and refinery capacity would be the bottleneck. Crude oil productive capacity, on the other hand, presently stands at 39% above normal production.* Further, the oft-quoted "12 years reserve-life" figure is not an estimate of what could be recovered by known methods from known fields. Such a definition would, rather, indicate a reserve life on the order of 36 years. Moreover, improved recovery methods are expected to double even this figure.

The second argument, that replacement of reserves requires exploration, has been discussed in Section IV. B. Exploration has in the past been the major source of reserve replacement, but will not necessarily be so in the future.

It is not within the scope of this study to determine whether

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*See footnote, p. 4.25.

government policy directed at increasing exploration requires a tax incentive rather than, or in addition to, other policy measures. Such would require analysis of all alternative government policies, while this study limits itself to the effects of tax provisions.

The question of how responsive is the industry as a whole to tax incentives in its exploration activity must be examined in the light of the determinants of exploration activity. It is quite possible that the industry can absorb a tax increase by shifting it forward to the consumer or back to its suppliers, or simply by cutting costs. Tax changes, if they are not absorbed, have an immediate effect on total profits, but total profits are not necessarily the major determinants of exploration. These questions are taken up in Chapter VI.

The fifth part of the national security argument is the concern of this chapter. If a tax incentive is necessary for exploration to continue at a high level, how far does the present tax structure succeed in increasing domestic exploration? This chapter discusses the magnitude and incidence of the special provisions which is a necessary preliminary to analyzing what they do.

B. Magnitude of the Benefits

While there are several sources of data for production, reserves, wells, costs and so on, there is little financial data except that provided by the Internal Revenue Service. The IRS is also the only direct source of data on the depletion allowance and the expensing provision.

It is almost impossible to obtain a time series of data showing the incidence of oil and gas depletion, but evidence may be gleaned from a momentary cross-section contained in the Treasury survey of depletion claims for 1958-1960,* and the published Statistics of Income Supplemental Report of depletion claims for 1960 only.** The Depletion Survey covers major claimants of depletion in all industrial divisions, but although it covers 99% of depletion claims for the refining industry, and 80% for the crude industry, it does not cover exploration deductions to the same extent.

The percentage depletion provision allows deductions over the producing life of a well which far exceed the initial investment; and, since a large part of the investment is written off for tax purposes as soon as the well begins to produce, percentage depletion exceeds allowable amortization of the remaining investment by an amount estimated between 80 and 97.5 percent of tax relief claimed. These estimates will be discussed in more detail below. The magnitude of the special

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*Depletion Survey 1958-1960, Treasury Department, February 6, 1963 (mimeo).

**Statistics of Income, 1960, Supplemental Report, Depletion Allowances for Mineral Production Reported on U.S. Tax Returns, Washington, D.C., 1966.

provisions can be indicated thus: If 80% of percentage depletion claimed for 1960 were "excess depletion" then the size of the excess depletion claimed would be approximately $2.3 billion,* giving a cash allowance to the industry of approximately $1.2 billion, against a gross declared income from oil and gas production of $10.7 billion.

The value of permission to expense rather than amortize expenditures derives from the value of deferring tax liability into the future. The size of the benefit is partly dependent on the estimated life of a well and partly on the rate of return used to estimate the present value of alternative time patterns of cash flows. A low estimate, taking the life of a well as 10 years and rate of return as 4% and allowing for a three-year gestation period, gives a present value for the deduction of $101 per $1000. A high estimate, although not at all an unrealistic one, taking the life of a well as 25 years and the rate of return as 9%, gives a present value for the deduction of $277 per $1000. (See Table 5.1)

If the whole of exploration and development expenditure is considered an investment, then the relevant source of the benefit is that part

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*Tax deduction	= $2.843 billion
Excess deduction	= .80 x $2.843 billion = $2.274 billion
Tax rate 52%	
Cash allowance	= $1.180 billion

of exploration and development expenditure which is deducted as a curr expense. The figures for 1960 are in Table 5.1. The value of expensin domestic dry holes is on a low estimate $79 million and on a high estimate $214 million. The value of expensing domestic intangible drilling costs is $119 million or $324 million. The total value of all expensed exploration and development expenditures, domestic and foreign, is at a low estimate $211 million and at a high estimate $572 million.

Table 5.2 shows the major claimants of depletion at the 27-1/2% rate, that is, oil and gas depletion in 1960. The total for active corporations, column 9, includes income and deductions for all industries; although included in this total, agriculture, construction and services are not shown separately since they account for a small amount of the income from oil and gas. The table (columns 10 and 11) also shows the individual and partnership returns with claims for depletion on oil and gas. The total depletion claimed in 1960 amounted to $2.8 billion.

Before discussing the implications of these figures, two concepts used in the discussion of depletion should be clarified. They are excess depletion, and the net income limitation.

1. Excess Depletion

The extent to which percentage depletion permits tax deductions to be taken in excess of amortization on original investment has not been

TABLE 5.1

HIGH & LOW ESTIMATES OF BENEFIT OF EXPENSING INVESTMENT IN OIL AND GAS *, 1960

Tax Rate 52%

High Estimate: Expenditures expensed in year undertaken. Rate of discount 9%. Average life of well 25 years.

Low Estimate: Expenditures expensed 3 years after undertaken. Rate of discount 4%. Average life of well 10 years.

	High	Low
DISCOUNT VALUES		
1. Present Value of $1,000 depreciated over life of asset	$394.2	$697.1
2. Present Value of $1,000 expensed	$917.2	$892.1
3. Difference (2.-1.)	$523.0	$195.0
4. Tax Benefit at tax rate of 52% per $1,000 Expenditure (52% of 3)	$276.6	$101.8
EXPENDITURES	$ Million	
5. Total Domestic & Foreign expensed investment (Sample)	2,068**	
6. Dry Hole costs, 1960 Domestic	774*	
7. Intangible Drilling Costs, 1960 Domestic	1,173*	
DISCOUNTED VALUE OF TAX BENEFITS		
8. Value of expensing Exploration & Development, Domestic & Foreign (5.x4.)	572	211
9. Value of Tax provisions, Domestic only:		
a. Dry Holes (6.x4.)	214	79
b. Intangible Costs (7.x4.)	324	119
c. Total Dry holes & Intangible Costs	538	198

* Source: Joint Association Surveys, 1960

** Treasury Depletion Survey of Large Companies covers 90% of depletion claimed and an unknown proportion of expenditures for oil and gas.

TABLE 5.2

SELECTED INCOME AND DEDUCTION ITEMS 1960, FOR INCOME TAX RETURNS WITH DEPLETION FOR OIL AND GAS

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	TOTAL ALL RETURNS WITH DEPLETION ON OIL AND GAS	ACTIVE CORPORATION RETURNS WITH DEPLETION									
		(1) By Industrial Division				(2) By Type of Interest					
		Manufacturing	Mining	Transportation, Electric, Gas etc.	Finance, Insurance and Real Estate	Operating Interest Only	Non-operating Interest Only	Both Operating and Non-operating Interest	TOTAL ACTIVE CORPORATION RETURNS	ACTIVE PARTNERSHIP RETURNS WITH DEPLETION	INDIVIDUAL RETURNS WITH DEPLETIONS
Number of Returns		465	3,086	200	12,569	2,742	13,153	1,288	7,183	8,793	
	MILLION OF DOLLARS										
Gross Income from Mineral Properties	10,[illegible]	[illegible],372	[illegible],200	528	276	1,929	199	7,305	9,434	331	886
Deductions exclusive Depletion Total	5,[illegible]70	3,[illegible]	895	306	47	836	15	3,475	4,327	198	646
Development	1,324	735	203	8[illegible]	7				1,037	48	240
Dry Hole deductions	166	121	15	[illegible]5	(.58)				141	4	20
Depreciation	[illegible]16	66	95	11	3				180	32	104
Operating Expense	[illegible],[illegible]31	1,993	41[illegible]	171	15				2,603	70	158
Taxes	130	38	[illegible]2	9	2				83	12	35
Overhead & Other	402	92	138	29	18				283	31	88
Net income less loss before Depletion	5,480	3,3[illegible]	1,304	222	230	1,093	184	3,830	5,107	134	240
Percentage Depletion at Statutory Rate	2,92[illegible]	1,752	605	145	76	531	55	2,009	2,594	91	244
Allowable Depletion Total	2,843	1,675	565	110	165	464	141	1,925	2,530	100	213
Percentage Depletion	2,506	1,590	528	86	35	419	18	1,814	2,251	65	190
Cost Depletion	336	85	37	24	131	45	123	111	279	34	24
Deductions on Non-producing Properties	1,610	1,095	266	85	10	187		1,278	1,465		[illegible]65

Source: Corporation Tax Returns, Depletion Study - 1960 definitively measured. This is important, for if percentage depletion were to be reduced or abolished, cost depletion would presumably be claimed instead.

The Treasury Depletion Survey gives estimates of excess depletion (see Table 5.3) derived from responses to the tax form for depletion claims, which requests estimates for two concepts: adjusted basis depletion and true cost depletion. No estimate of true cost depletion appears in the survey; the figures in Table 5.3 represent excess depletion over adjusted basis depletion.

Adjusted basis depletion in any year is the cost depletion which could have been claimed in that year. This is calculated as described in Section IV.C and represents amortization of the remaining cost base, which may have been adjusted for previous percentage depletion claims. True cost depletion is the cost depletion which could have been claimed if only cost depletion had been claimed since the well was drilled.

This distinction does not, however, take into account the acquisition costs paid for producing properties, which represent discovery value rather than amortizable exploration costs. A distinction should be made between "exploration cost depletion," including acquisition costs for non-producing properties, and "acquisition cost depletion," including acquisition costs for producing properties. For this reason, the authors question the figure presented as "excess depletion over adjusted basis

TABLE 5.3

SELECT PERCENTAGES, BY INDUSTRIAL GROUPS OF REPORTING CORPORATIONS IN OIL AND GAS PRODUCTION, 1958 - 1960.

Industrial Group and Year	Depletion Claimed on Tax Return as % of: Taxpayers Gross Income Subject to Depletion	Depletion Claimed on Tax Return as % of: Net Income from Properties Before Depletion	Excess Depletion Claimed Over Adjusted Basis Depletion as a % of Depletion Claimed on Tax Return
All Industrial Groups			
1958	26.2	47.2	92.0
1959	26.2	49.2	90.6
1960	26.8	48.2	90.9
Crude Petroleum and Natural Gas			
1958	26.2	39.6	95.3
1959	26.4	40.3	94.2
1960	26.7	39.4	94.6
Petroleum Refining			
1958	25.9	48.2	93.5
1959	25.5	50.9	92.8
1960	26.2	49.7	93.0
Holding & Other Investment Companies			
1958	64.6	90.8	9.4
1959	69.0	92.8	6.1
1960	68.8	97.2	6.0
Transportation, Electric & Gas			
1958	23.2	68.7	82.7
1959	24.1	68.4	77.1
1960	24.6	63.5	75.8

Source: Treasury Depletion Survey, Table 4,5,6;

[redacted]

depletion as a percent of total depletion claimed." As an estimate of the excess over true cost depletion, it is likely to be too high; and, because of the acquisition costs for producing properties, the excess over adjusted base is likely to be too low.

To confirm that the global figure of 90.9% excess depletion is just such a hybrid, consider the spread between producing industries, where excess depletion is nearer 95%, and non-producing industries, where excess depletion is nearer 6%. This shows that cost depletion does in fact have two different meanings, and that the Treasury figure does not give a genuine estimate.

The study's estimate of excess of depletion claimed over adjusted basis depletion based on exploratory costs is 97%, and, over true cost depletion, is 87%. This compares with the 80% used by Stigler,* and based on a small sample of companies. McDonald** quotes an estimate of the "sacrifice of cost depletion" as 2.9% of gross income, which gives excess-depletion estimates of 88%. The contexts suggest that the estimates correspond to "true cost depletion," in the Treasury sense.

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*Stigler, G., Capital and Rates of Return in Manufacturing Industry, National Bureau of Economic Research, Princeton, New Jersey, 1963.

**McDonald, Stephen L., Federal Tax Treatment of Income from Oil and Gas, The Brookings Institution, Washington, D.C., 1963.

The following calculation of excess depletion is based on data derived from Joint Association Surveys and American Petroleum Institute publications. No IRS data was used at all.

The ratio of proved reserves to production has remained virtually constant at 1:12 for 20 years. If 1/12 of remaining reserves (roughly 8%) is removed each year from each well, there is a declining production curve for each well, and the well will be reduced to 10% of its original reserve in place after 30 years.

The 1959 cohort of exploratory wells will be traced through its expected life assuming:

1) price constant at $2.90 per barrel,

2) depletion rate equals 27-1/2%,

3) 8% of remaining reserves are drawn from each well each year.

The domestic geological, geophysical and acquisition costs undertaken in 1959 equalled $1,191,000,000.* Of all exploratory wells, 19.82% were successful.** Therefore, the net addition to the depletable asset account is taken as $236 million. This is the amortizable cost

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*Joint Association Survey, 1959.

**See Table A.19.

base for the expected life of the 1959 cohort of exploratory wells. The true cost depletion over the life of the well would equal this sum.

It is assumed that, in 1960, the development expenditures on the 1959 exploratory wells were high enough to push percentage depletion so low (by the net income limitation) that cost depletion was taken. Thereafter, it is assumed that the net income limitation did not come into play, and that 27-1/2% was taken throughout the life of the well.

It is further assumed that development will increase the initial estimate of reserves discovered in 1960 to 6 times the original figure (6 x 369,362,000 = 2,216,172,000 bbls).

This method of derivation gives a picture of a time series for a single cohort of wells under a constant price; if the price rises during the life of a well, excess depletion will be higher. Results are shown in Table 5.4.

2. Net Income Limitation

Figure 5.1 shows the effect of the net income limitation. The upper line shows the effective tax rate for different cost/income levels. The effective tax rate for a corporation paying tax at 50% with no operating cost is 36-1/4%. This effective rate declines until its lower level is set at 25% by the net income limitation. All producers with a high ratio of deduction/income pay tax at this rate. The lower line shows

TABLE 5.4

CALCULATION OF EXCESS DEPLETION, 1959 COHORT OF EXPLORATION WELLS

Depletable cost base (see text) $236,056,200
Original reserves (see text) 2,216,172,000 barrels

Year	(1) Reserves remaining end of year	(2) Production = 8% of remaining reserves	(3) Value of production at $2.90 per bbl	(4) Percentage depletion at 27 1/2%	(5) Remaining cost base, beginning of year (adjusted each year by depletion actually claimed)	(6) Allowable Adjusted Base Depletion (5) x (2)/(1)	(7) Cost Base, if only cost depletion taken (adjusted by 8% of itself each year)	(8) Allowable True Cost Depletion (7) x (2)/(1)
	Millions bbls	Millions bbls	$ Millions	$ Millions	$ Millions	$ Millions	$ Millions	$ Millions
1959	2,216							
1960	2,039	177.3	514.1	141.4	236.1	* 18.9	236.1	18.9
1961	1,876	163.1	473.0	* 130.1	217.2	17.4	217.2	17.4
1962	1,726	150.1	435.2	* 119.7	87.1	7.0	199.8	15.0
1963	1,588	138.1	380.1	* 104.5	0	0	183.8	14.7
⋮								
Total over life		2216.2	6427.0	1767.4		43.2		236.1

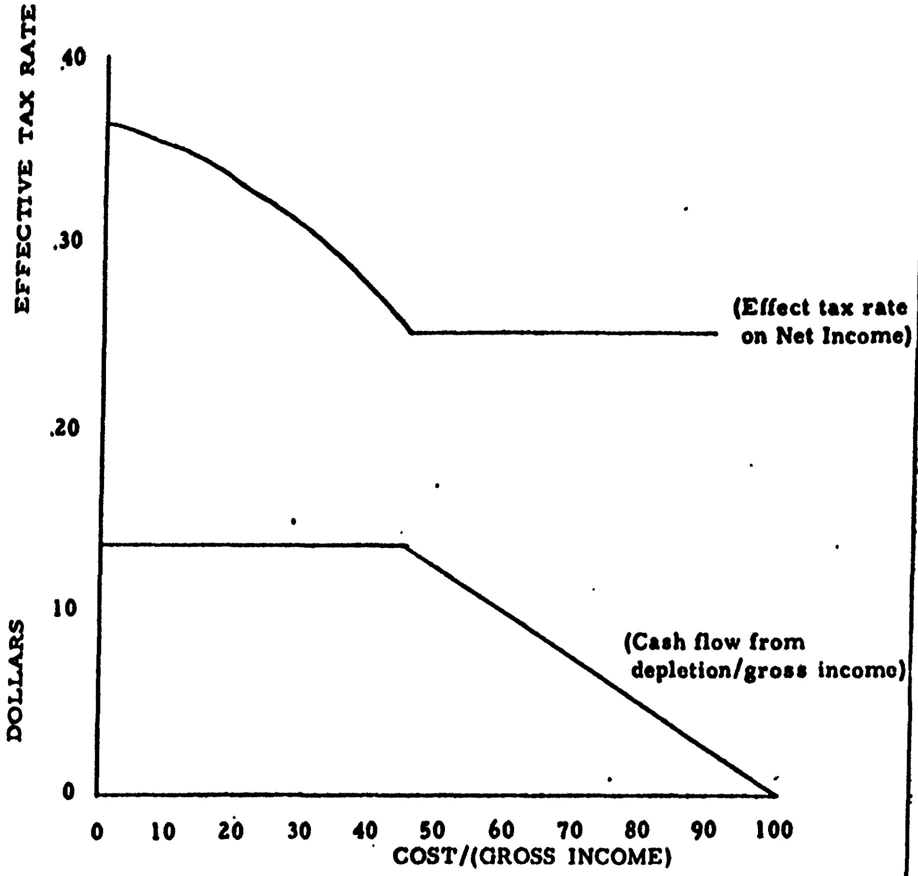
Depletion actually claimed

Depletion actually claimed over life of well	= 1767.4 - (141.4 - 18.9) = $1644.9 million
Allowable true cost depletion over life of well	= 236.1
Allowable adjusted base depletion over life of well	43.2
Excess over true cost depletion	= 1408.8 = 85.6%
Excess over adjusted base depletion	= 1601.7 = 97.4%

FIGURE 5.1

BENEFITS OF DEPLETION AT DIFFERENT LEVELS OF COST/GROSS INCOME: THE EFFECT OF THE NET INCOME LIMITATION

Tax rate 50%



the benefit of the depletion provision in terms of effective cash flow per $100 gross income from oil and gas. This is constant at $13.75 up to the net income limitation, whereafter it declines linearily as costs rise. It can be seen that those operators whose high expenses put them well above the 50% limitation derive less tax benefit for each barrel of oil they produce than do the lower-cost producers and the non-operating interests. It is possible, however, to avoid the net income limitation by carrying expensing forward five years or back for two. Despite all these means of avoiding the limitation, the sample included in the Treasury survey of the years 1958-60 showed that in 1960, approximately 19% of domestic percentage depletion was claimed under the net income limitation, while foreign operators claimed only 3.5% under the limitation. This reduced percentage depletion claims to below the standard 27-1/2% level. The incidence of the limitation is difficult to measure,* for aggregate measures of income and deductions include figures for companies which made a loss. Percentage depletion is claimed only on producing

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*The 1958-1960 U.S. Treasury Study presents a table showing the percentage distribution of percentage depletion claimed by the ratio of percentage depletion to positive net income. This cannot, however, be used to measure the effect of the net income limitation since it represents an aggregation of claims for each company, and not a distribution by individual properties. This can be seen from the fact that the distribution table shows only 2% of depletion claimed under the net income limitation whereas other data in the Survey shows 19% claimed in this way.

properties showing a net profit, so that the ratio of aggregate depletion to aggregate net income may rise above 50%. Further, since cost depletion is an option, it is impossible to tell how much of the depletion loss from the net income limitation is compensated for by cost depletion claims.

One rough measure of the distributional effects of the net income limitation is the change in the ratio of depletion claimed to gross income, by asset size, as reported in Statistics of Income Source Books. This suffers from all the deficiencies mentioned above, with the additional deficiency that not all gross income of all producing companies is derived from mineral production. In the refining companies, this factor is so large that comparison is valueless. In the crude oil industry, however, it is possible to make a rough comparison.

Table 5.5 shows the ratio of depletion claimed to gross income by asset size for four years. The ratio increases up to the $100,000 asset firms and declines for the two larger groups. This is probably because the larger firms are diversifying and the gross income figure is therefore inflated. The mean figure is well below the figures given in the Statistics of Income Supplemental Report, which also suggests that the reported income is from sources other than oil and gas products. The table is not, however, conclusive.

TABLE 5.5

DEPLETION ALLOWED AS PERCENT OF GROSS RECEIPT

CRUDE OIL INDUSTRY BY ASSET SIZE: REFINING INDUSTRY TOTAL

	CRUDE OIL RETURNS WITH NET INCOME													TOTAL REFINING
	0 50	50 100	100 < 500	500< 1,000	1. < 2,500	2.5< 5000	5 < 10,000	10 < 25,000	25 < 50,000	50 < 100,000	100< 250,000	More than 250,000	Total	
1958	9.8	20.8	16.5	11.9	22.4	18.4	21.0	11.0	21.8	15.5	18.0	16.4	17.0	4.8
1959	17.3	14.9	15.4	17.1	16.1	16.1	14.6	12.9	19.9	22.1	15.3	16.2	16.6	6.3
1960	15.3	15.1	15.7	20.6	18.2	18.9	17.4	13.1	22.6	28.1	15.0	14.9	16.5	4.7
1961	16.5	19.2	11.0	13.0	20.9	20.5	17.6	15.2	22.6	40.6	12.2	14.9	15.9	4.9
Mean 1958-61	14.6	17.5	14.6	15.6	19.4	18.4	17.6	13.0	21.7	26.5	15.1	15.6	16.5	5.1

Source: Corporation Tax Returns; prepared by Simon M. Simon

C. Incidence of Benefits

1. Foreign Properties

American-based companies producing abroad claim depletion on foreign properties. Since foreign wellhead prices are lower, depletion is a smaller sum per barrel but it amounted to a total of $655,000,000 in 1960 for the companies covered in the Treasury Depletion Survey. This represents 23% of all depletion claimed.* (See Table 5.6)

2. Non-Operating Interests - Royalties

Non-operating interests receive income from production by means of production payments or in-oil payments from royalties, rentals, lease bonuses and various other devices. This income is subject to percentage depletion. The operating interests who make the payment deduct the payments from their gross income before calculating depletion allowances.

Although there is no data on royalties, it is generally believed that royalties on private lands amount to about 1/8 of the value of production. On Federal lands, they amount to more than this. Some landowners apparently receive 50% or more. The Joint Association Survey uses the figure of 15% to adjust production figures for the amount accruing

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*Assuming that those companies, partnerships and individuals not included in the Survey are entirely engaged in domestic production. For companies included in the Survey, 29% of all depletion is claimed on foreign properties.

TABLE 5.6

DOMESTIC AND FOREIGN ACTIVITIES
DEDUCTIONS AND RELATIVE RETURNS TO PRODUCTION

	DOMESTIC PROPERTIES			FOREIGN PROPERTIES		
	1958	1959	1960	1958	1959	1960
	MILLION DOLLARS					
Number of Companies	182	187	185	60	63	63
Gross Income from Oil and Gas Production	5,571	5,809	6,073	2,373	2,286	2,388
Less: Deductions on Producing Properties[a]	952	1,000	923	213	223	172
Other Deductions[b]	1,804	2,007	2,062	443	437	467
Equals: Net Income Before Depletion	2,815	2,802	3,088	1,717	1,626	1,749
Less: Total Depletion Claimed	1,440	1,506	1,613	642	613	655
Based on Gross Income Rate	1,139	1,143	1,209	618	558	618
Based on Net Income	211	250	267	10	35	22
Adjusted Basis (Cost Depletion)	90	112	137	14	19	15
Less: Deductions on Non-producing Properties[a]	1,125	1,171	1,188	243	275	352
Equals:[b]	250	125	287	832	738	742
Tax at mean 52% =	130	65	149	433	434	386
Income after tax =	120	60	138	398	354	356
Income after tax + 80% Percentage depletion claimed =	1,200	1,174	1,318	900	828	868
Profit per $100 Gross Income	21.5%	20.2%	21.7%	37.9%	36.2%	36.3%

June 30, 1966

a This figure slightly understates the total of deductions in this category since 3 percent of the total deductions were not allocated between producing and non-producing properties in the Treasury Depletion Survey. Other deductions are correspondingly overstated.

b Derived as a residual from other data in the table in royalties. Since royalty owners have no operating expenses, they do not encounter the net income limitation and take the full 27-1/2% allowance.

3. Non-Operating Interests - Cost Depletion

When the depletion figures are examined more closely, a remarkable discrepancy appears. Table 5.3 shows excess depletion claimed* over adjusted cost basis depletion for all properties claiming depletion of 27-1/2% (this rate applies only to oil and gas). For 1960, it appears that excess depletion was 90.9% of total depletion claimed. This suggests that what could have been claimed as adjusted basis depletion was 9.1% of total depletion that was claimed, or approximately $200 million.

Now, since allowable adjusted basis depletion represents the remaining cost base times the fraction of the physical base removed, it should be possible to estimate the cost base, given that the proportion removed was somewhere between 1/12 (crude oil) and 1/18 (natural gas). This gives an adjusted cost base of between $2,400 million and $3,600 million. However, the 1960 additions to the depletable assets account

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*Excess depletion = $\frac{\text{total depletion claimed - adjusted basis depletion}}{\text{total depletion claimed}}$

This figure includes claims for domestic and foreign properties, but as has been discussed, it is a plausible estimate. Figures following have been adjusted to show only domestic properties. Unless otherwise indicated, figures are from the Depletion Survey for 1958-60.

from domestic geological and geophysical, lease bonuses, etc., totalled $177 million by the Treasury estimate, or $320 million by the Industry estimate. Of these, about 20% resulted in successful wells, so that the net addition to the cost base from geological expenditures and rentals for 1960 would have been at the very most $65 million. At that rate, it would have required more than 40 years without depletion to acquire a cost base so large. Further, an exploratory well driller will generally charge cost depletion only in the initial stage because of the net income limitation. Almost as soon as he begins to charge percentage depletion, the cost base will be eroded and there will be 100% excess depletion over most of the life of the well.

How, then, can the apparently large cost base be explained? First, the depletable assets account also includes acquisition costs, which amounted to an additional $718 million* in 1960. If these also represented exploratory expenditures, the net addition to the depletable assets account would be an extra $145 million, but this still does not account for the size of the cost base. If the acquisition costs represent both exploratory and development expenditures, the overall success ratio of 60% would give an addition of $430 million. Even in the outside limit

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*Joint Association Survey estimate $626 million.

case, the cost base would represent 4-6 years undepleted additions. Since percentage depletion claimed each year is approximately the same size as the cost base, it is evident that cost and percentage depletion are taken on different types of property.

Part of the answer appears in Table 5.3. The excess depletion for the petroleum industry is considerably higher than 90.9%. In 1960, it was 94.6% in crude petroleum and 93.0% in refining. But, in the "holding and other investment companies," it is only 6%, indicating that almost all depletion taken by the holding companies is taken as cost depletion.

Again, depletion claimed by holding and investment companies has risen from 0.6% of all depletion claimed in 1952, to 3.9%, or $130 million in 1960. Table 5.3 also shows why cost depletion is taken, since it has permitted holding and investment companies (which are a major part of the financial sector) to claim 97.2% of net income from mineral properties as a tax deduction. This percentage has been increasing rapidly; the net income limitation does not apply to cost depletion.

Evidently, this enormous tax deduction does not arise from the sudden interest of the holding and investment companies in exploration for, in 1960 while they claimed 3.9% of all depletion, they expended less than 0.19% of exploration expenditures and 0.25% of development costs, and were able to deduct more than 93% of these as current expenditures. The finance industry as a whole claimed 6.7% of all depletion in 1960.

The curious position of the finance industry derives from a 1958 court ruling* that effectively allowed both cost depletion and percentage depletion to be taken on the same property by means of a transaction known as the ABC deal. The apparently large cost base is derived from acquisition costs for successful wells, which are recouped on a long-term basis, in addition to percentage depletion.

The implications of this are only incidental to this report, since 3.9% is perhaps marginal. However, the increasing importance of the finance companies to the oil industry in the period from 1958 to 1960 leads one to suppose that, in the seven years for which data are not yet available, this transaction has assumed a greater importance. Further, in the absence of percentage depletion, the device of realizing the discovery value by inter-company sales of property and thus establishing a new acquisition base on which to take for cost depletion might compensate for the lost tax benefit. The limiting factors would be the

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*Commissioner v P.G. Lake, Inc., 356 U.S. 260 (1958). For a full discussion of the legal principles and practical effects of various devices employed for maximizing tax benefits, see Galvin, Charles, "The 'Ought' and 'Is' of Oil and Gas Taxation," Harvard Law Review, June, 1960.

expected present value of the tax benefit to be gained over the life of the well, compared with the capital gains tax to be paid immediately to such a transaction. This would in turn depend on the expected life of the well and the relevant discount rate.

Depletion allowed on foreign properties and to non-operating interests in domestic properties evidently has no direct effect on domestic exploration, yet accounts for more than half of all depletion claimed. Attention is now turned to domestic explorer-producers (who claim depletion) to see how the subsidy is divided among them and to compare, where possible, the tax benefit with the cost.

4. Distribution of Depletion by Industrial Sector

Table 5.2 shows income, deduction and depletion items for several industries claiming depletion. Agriculture, construction and services are not shown separately, although they are included in the total, since they account for so small a proportion of all claims.

Table 5.2 unfortunately gives no figure for deductions related to exploration: These are presumably included in the development deduction in the case of successful wells, and in the deductions for non-producing properties in the case of unsuccessful wells. Taking this latter figure for deductions on non-producing properties as an indicator of how far each industrial sector is engaged in exploration, it is possible to compare the depletion benefits with the supposed risk of exploration. Mining claims 25% of gross income from oil and gas as depletion, and dry-hole costs account for 12.1% of gross income. In manufacturing, the percentages are 26.3% and 17.2%; in finance, 59.8% and 3.6%; and, in transportation and utilities, 20.6% and 16.1%.

Table 5.2 also shows the relative importance of cost depletion to the industrial sectors. Cost depletion, it will be recalled, may be claimed by high-cost operators or, more importantly, by non-operating interests. In manufacturing, which is mainly represented by petroleum refining, cost depletion is a very small proportion of depletion claimed (5.1%). In mining, it is slightly higher (6.5%). It is difficult to know whether this reflects a higher incidence of amortization of exploration costs, or acquisition costs for producing properties, but the fact that depletion is a smaller percentage of gross income suggests that the former explanation is the correct one. The finance industry claims 60% of its income as depletion, which it is able to do because it claims 79% of its depletion as cost depletion, presumably via the ABC deal. Transportation, electricity and gas claim 21% of depletion as cost depletion, a high proportion compared with manufacturing or mining. However, that 20% of its gross income is claimed as depletion, suggests the diversity of this industry. On inspection of the 1958-1960 Depletion

Survey, this proves to be the case, with the transportation sector behaving as the finance industry, and claiming high cost depletion and a high percentage of gross income, while the gas and electricity industry behaves more, although not yet entirely, as an operating interest, with a lower proportion of gross income claimed in depletion, and a small incidence of cost depletion.

5. Distribution of Depletion by Size of Company

The information on the distribution of depletion by size of company is derived indirectly. Since percentage depletion is based on production, it is likely that production figures would be an indication of the amount of depletion claimed, unless royalties differ systematically or unless some producers systematically encounter the net income limitation. It was argued earlier that the net income limitation is likely to affect the smaller producers. Initially, the effect of the net income limitation will be ignored and production will be taken as a proxy for depletion.

The data which relates production and exploration expenditures to companies is sparse but informative. In 1965, the first five companies account for 25% of domestic production of crude oil and natural gas liquids, the first 20 companies for 50%, and the first 35 companies for 60%. In 1960, the five largest companies accounted for 23% of domestic production; the first 20 again for 50%, and the first 35 for 55%. There has been a tendency toward concentration which is not uniform, since it partly represents an increase in market share for the top five at the expense of the medium-sized organizations. However, the shift of 5% of market shares into the top 35 firms is a significant loss to the smaller firms who, in absolute terms, are producing less crude and natural gas liquids than they did in 1960.

The ranking of firms, by number of wells drilled domestically, shows a distinct difference. The first 65 companies drilled only 30% of the wells in 1965 and 28% of them in 1960. In 1963, the 200 largest companies drilled 40% of all wells.*

However, number of wells drilled is perhaps not the best measure of exploratory effort, since larger companies dig deeper and spend more per well. There are no indications of individual companys' expenditures, but it is known, for example, that the share of expenditures accounted for by the Chase Manhattan group of 30 companies has risen from 52% to 68%.**

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*See Tables A.23, A.28 and A.29.

**See Table A.9.

6. Effects of the Provision to Expense Exploration and Development Cost

The provision to expense exploration and development costs results, unlike the depletion provision, in a direct benefit to those who undertake exploration and development. It is, however, to some extent competitive with the depletion allowance, since the cash flow from depletion decreases as soon as expenses on producing properties exceed 45% of gross income. This may retard development expenditure for those small companies which are only marginally engaged in production, and who are not able to avoid the net income limitation.

For the companies which are not in danger of encountering the net income limitation, the provision to expense most of exploration and development expenditures may encourage over-drilling. For these companies, for every extra dollar of expenditure, half is effectively paid by the government with no waiting period. However, half is still paid by the company, so that there is a limit on how much will be risked on relatively unlikely prospects. The powerful incentive to drill comes from state regulations which limit production on each well but allow some production from every well. A development well is more risk-free than an exploratory well and achieves the required result of increasing allowable production. Since the incremental cost of a development well, taking into account the probability of finding a dry hole and the average depth of wells, is relatively small, state regulations are more likely to encourage over-development than excess exploration. On the other hand, deductions for unsuccessful exploratory wells are not included in computing the net income limitation, which may encourage excessive exploration. The depletion allowance on production also adds to the incentive to over-develop, since it exaggerates the expected return to production and provides a margin within which wasteful excess expenditure can be absorbed.

Of the two factors relevant to domestic over-development, it is believed that the state regulations are the greater. The evidence for this is derived from a comparison of tax deductions for exploration and for development claimed by United States companies with both domestic and foreign operations. Assume that there is some optimum ratio of development to exploratory wells. Since both domestic and foreign operations are subject to the same tax provision, the difference in ratio between development and exploration expenditures should give some indication of the effect of state regulations. Foreign operations may be influenced by the tax provisions to over-development but the fields are generally subject to extremely wide single-company concessions, with no "allowables." Hence, there is no other incentive to drill more wells than are strictly necessary.

Table 5.7 shows that a smaller proportion of gross income is invested in exploration abroad than domestically, which may reflect greater ease of finding. However, the ratio of development expenditure abroad to exploration expenditures is between 1.3 to 1 and 1.5 to 1 in the years 1958-60, while the corresponding domestic ratio is between 2.6 to 1 and 3.2 to 1, suggesting that approximately half of domestic development expenditure is in excess of basic requirements. Since development wells are shallower and therefore less costly, it is likely that more than half of development wells drilled, or some 17,500 per year, are in fact superfluous to normal production. At the end of 1965, there were 588,000 wells in production and an excess capacity of 39%, so that the order of magnitude of this estimate is plausible.*

A further modification should be made to this argument, for if there is an optimum ratio between exploration and development, it is more likely to be the ratio of successful exploratory wells to development wells. The domestic and foreign exploration/development ratios would then have to be divided by the success rate for exploratory wells to give a true comparison bearing on over-development. The 50% figure for over-development assumes equal exploratory success rates. However,

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*See Table A.19.

TABLE 5.7

DOMESTIC AND FOREIGN ACTIVITIES 1960
EXPLORATION AND DEVELOPMENT EXPENSES

	Domestic Properties			Foreign Properties		
	1958	1959	1960	1958	1959	1960
			(MILLION DOLLARS)			
Gross Income, Gas & Oil Production	5,571	5,809	6,073	2,373	2,286	2,388
Exploration Expenses	892	914	918	297	310	269
Development Expenses	1,522	1,632	1,600	374	343	306
Other Acquisition Costs	418	645	718	65	59	34
Percent of Gross Income Expended						
for exploration	16.0	15.8	15.1	12.5	13.5	11.3
for development	34.7	39.2	38.2	18.5	17.5	14.3
for exploration & development	50.7	55.0	53.3	31.0	31.0	25.6

Source: Treasury Department Survey; 1962 if exploratory drilling had a higher success rate abroad, the estimated figure for domestic over-development would be higher. The proportionally lower exploration costs and the tendency of large companies to produce abroad suggest that at least as much success in exploration abroad as domestically. However, no firm data exist on this point. It has been argued by Harberger and Steiner* that the special provisions lead to a wasteful misallocation of capital to the oil and gas industry, a position which has been disputed by McDonald,** who holds that a standard rate of corporation tax is not necessarily neutral in its effects on resource allocation and that, if the rate of capital turnover in each industry is taken into account, the depletion allowance may be found to be a neutralizing rather than a non-neutralizing factor.

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*Tax Revision Compendium, papers presented to the Committee on Ways and Means, U.S. House of Representatives, November, 1959.

**See, for example, "Percentage Depletion and the Allocation of Resources: The Case of Oil and Gas," National Tax Journal, Vol. XIV.

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VI. MODELS OF THE DETERMINATION OF RESERVE LEVELS

This chapter discusses the determinants of reserve levels, as related to incentives to invest in exploration and development. It discusses possible methods for predicting the effects on reserve levels of tax policy.

Three basically different approaches are presented. Two of these are aimed at evaluating industry reactions to policy changes, while the third is aimed at evaluating the reaction of individual firms.

A. Exploration and Development Expenditures

Reserve levels are a stock which is reduced as crude (or natural gas) is produced and sold and which is increased by the discovery of new reserves through exploration and development. This section discusses the possible determinants of investment in exploration and development from a theoretical viewpoint, examines their appropriateness in the present context, and finally considers the recent history of exploration in the light of the preceding discussion. In order to develop a model which adequately predicts the levels of reserves in the petroleum industry, it is necessary to consider in detail the determinants of exploration and development effort.

1. Theory of Investment

Exploration and development in the petroleum industry is a type of investment in capital assets. Consequently, it seems appropriate to investigate classical economic theory related to capital-asset investment and holding as a starting point for determination of the factors affecting reserve levels. Much of the literature analyzing the determinants of investment rests upon the assumption that businessmen try to maximize their profits. They invest in those projects which promise the best rate of return.

Alternative to this classical theory is that of the "profit satisfier," which holds that investment will take place in an industry as long as profits are, by some definition, "satisfactory," so that investors do not continually search for better investment opportunities but, rather, maintain existing patterns of investment within wide variations in returns.

Previous empirical work has followed two alternative paths. One has been to relate changes in such explanatory variables as rate of return, cash flow, or demand to changes in investment. This approach is basically empirical in nature, although the explanatory relationships typically do have some theoretical basis. The other has been to utilize the conditions of economic equilibrium (primarily marginal conditions) to determine the relative weights of basic variables in determining the levels of capital stock. Both of these are subject to criticism, but, as yet, no clearly preferable approach has been presented.

The purpose of this study required that the investment hypothesis chosen meet two criteria -- first, that data be available to calibrate it, and, second, that it include as determining variables the magnitude which would change with changes in tax provisions.

B. Application to the Oil Industry

Investment analysis, as developed for manufacturing, is best applied with caution to the oil industry. First, the theoretical background sketched above applies to the behavior of a single firm in a competitive industry which is neither growing very rapidly nor declining. The oil industry, and particularly its exploration sector, has, so far as it is possible to tell from the sparse financial data available, been passing from a period of high and increasing demand and high profits to a period of more stable demand and lower profits. As Marion H. Stekoll, President of the Stekoll Petroleum Company put it in a 1961 seminar paper to the International Oil and Gas Education Center:

> The basic problem of the U.S. oil industry is the necessity to realize fully its present status. This is a difficult problem to comprehend fully, as we have been in a highly profitable industry a long time: not in terms of history, but in terms of our own lifetimes. It is hard, perhaps impossible for many, to realize that the "good old days" have gone the way of the buggy whip and the

> ravaging of national forests. Like nearly all people of wealth, many oil operators spent freely in the past, knowing that more wealth was available by drilling more wells. A complete realization, from company owner or president to pumper and roustabout, of the present and future condition of oil and gas production is perhaps the most basic requirement of the industry today. This is not a suggestion of pessimism, but one of facing facts fully and boldly.*

In the same seminar, this was underlined by a petroleum consultant, D. M. E. McLarty, who said:

> In the post World War II "Golden Age of Exploration," cost was not a consideration in finding oil. If an operator found any appreciable amount of oil it was automatically profitable. Exploration men knew costs were rising. They knew their rapidly growing operations were inefficient and wasteful. But if expansion was halted long enough to eliminate waste and restore efficiency, then profitable opportunities would be lost and the operator would fall behind in the oil-finding race.
>
> In the good years, the object of exploration was simply to find oil -- nothing more. And every effort was concentrated on achieving this object to the exclusion of all other considerations.**

The immediate past may well have been a period of readjustment for the industry, during which exploration policies were examined and costs and technology reconsidered; and extrapolation from this period

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*Economics of Petroleum Exploration Development and Property Evaluation, New Jersey, 1961, p. 130.

**Op. cit., p. 78.

may thus not be entirely relevant to the future of the industry.

Second, the behavior of an entire industry is more difficult to explain than that of a single firm, particularly since, in dealing with average figures for a number of firms, little information is usually available about the distribution. There is evidence that smaller companies have been leaving the industry or merging. However, there is no reason to suppose that there has been a net outflow of assets. Both crude oil and petroleum refining appear to have held their own with manufacturing industry in asset increase as reported in Corporation Tax Returns. The overall figure may, however, mask a shift abroad or into refining rather than domestic oil and gas production.

The third difference between oil and the other industries is that the oil industry does not invest in quite the same way as other industries do. Normally, investment is considered to be the purchase of durable assets which increase productive capacity, with "durable" taken for tax purposes to mean having a life of more than one year. In this case, the increase in assets recorded in the balance sheet (net of depreciation) is equal to the amount of net investment undertaken beyond replacements. The decisions made in the board room are reflected in the asset account.

In the case of oil and gas production, the decision is made to explore; and, if oil is found, the asset account may increase by many times the initial expenditure. Further, a large part of exploration and development expenditure has, in the period under study, been considered for tax purposes as current expenditure, which means that it has not tied up company assets to the same extent as manufacturing investment. This may be taken to indicate that capital has been relatively more free to move in and out of exploration and can, therefore, be sensitive to expected profit; or it may suggest that, since it is easier to "pull out," there is less need to be sensitive to small fluctuations in expected profits, as measured by realized profits in the previous period.

It must also be recognized that the oil and gas industry includes a variety of different types of operator. Thirty companies account for 60% of domestic crude oil production and 68% of exploration and development expenditures.* Typically, these large firms have considerable investments in oil production abroad, and are integrated from exploration through the final petroleum products. Larger firms dig deeper wells and find fewer dry holes.** In other words, they are more efficient than small firms. They are also likely to be subject to different influences on their investment behavior. Small firms are less likely to have either free access to capital or to consider foreign exploration as a relevant alternative to domestic exploration. Consequently,

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*See Tables A.1 and A.9.
**See Table A.23.

industry aggregate data may obscure some of the underlying behavior of the individual firms.

It is believed, although the data available again does not prove or disprove this hypothesis, that the small exploration companies are largely financed by the large integrated companies, directly or by purchase or by contract. If such is the case, pressures on the integrated companies will indirectly affect the small exploration companies and it may be that the latter will be the first to feel the financial pressures.

The large integrated company has not only to consider profits on oil and gas production. Refineries are expensive but profitable capital assets, and expenditures for exploration form a small, although not insignificant, part of the yearly budget. This is not, however, comparable to the chemical industry's expenditure for research and development because a continuing supply of crude oil is the *sine qua non* of a large and profitable refining industry. For large companies, it is probably true that, so long as it is profitable to remain in the industry, it is also profitable to seek new sources of oil, although not necessarily through exploration. New oil may also be "sought" through better recovery methods or purchase of reserves in the ground.

1. Erosion of the Resource Base

The over-riding determinant of domestic exploration activity may be the expectation of finding oil. This expectation would not, of course, respond to tax policy, but it should be investigated.

If a rational producer were faced with a series of investment decisions yielding different expected returns, he would take the prospect with the highest expected yield and work his way down the inventory of prospects. Thus, the more investment he undertakes, the lower the expected yield on the last project.

How far is this applicable to the oil industry? Is it true that oil is becoming more and more difficult to find? If so, what implications does this have for the future of exploration, and for the future availability of reserves?

First, the oil industry is not at any one time in possession of all relevant knowledge about the ranking of prospective fields. The effective inventory at any time consists of those areas for which adequate geological and geophysical preparations have taken place. Taking year-to-year changes in the overall success ratio, Fisher* found that, in years when a large increase in wildcat drilling took place, the success

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*Franklin M. Fisher, Supply and Costs in the U.S. Petroleum Industry: Two Economic Studies, Resources for the Future, Inc., The John Hopkins Press, Baltimore, Maryland, 1964.

ratio dropped slightly, a fact which he attributed to working down the list of prospects. However, since the success rate for wildcat drilling shows a remarkable constancy over time, it cannot necessarily be assumed that some overall inventory of potential possibilities is being systematically eroded. New possibilities must be joining the inventory each year as geological and geophysical surveys cover more potential oil ground. However, one would expect there to be some ordering in the choices of areas for geological and geophysical surveying, so that the success rate should show a tendency to diminish over time, and its consistency for the past 20 years can presumably be attributed to two effects: One is the progress made in geological technology, and particularly in geophysics; the second is the fact that new techniques permit the drilling of deeper wells. The inventory of prospects has been expanded so that, although the easier prospects are gone, there may still be large fields awaiting discoveries.

The statistics for wildcat drilling, therefore, give no indication as to whether the resource base has been systematically eroded, i.e., whether the same amount of exploratory effort is producing fewer reserves. A beginning has been made at estimating the factor. The series in Table 6.1 shows estimates of size of fields discovered in various years, estimated six years from the date of discovery of the field. The second part of the table shows each size category as a

TABLE 6.1

SIZE DISTRIBUTION OF NEW FIELDS

Estimated total ultimate recoverable reserves after six years of development history, oil and gas reserves, new field wildcats, 17 states only.

Size / Year	over 50m	25-50m	10-25m	1-10m	less than 1m	Unprofitable	Total new field discoveries
	barrels of oil or equivalent gas, or comb.						
1943	7	9	17	69	200	25	327
1944	6	3	27	67	141	36	280
45	6	3	23	77	139	52	300
46	3	3	17	72	149	44	288
47	8	12	15	82	164	67	348
48	5	5	16	92	276	52	446
49	17	11	17	99	215	90	449
50	7	14	23	97	327	75	543
51	11	5	23	112	402	77	630
52	12	9	18	114	426	105	684
53	4	9	23	128	372	152	688
54	6	4	24	133	412	218	797
55	4	8	24	128	436	221	821
56	2	6	7	144	425	150	734
57	10	6	22	133	444	216	831

Year	Percentage Distribution over 50m	25-50m	10-25m	1-10m	less than 1m	Unprofitable	Total
1943	2.14	2.75	5.2	21.1	61.2	7.65	100
1944	2.14	1.07	9.6	23.9	50.35	12.86	100
45	2.00	1.00	7.67	25.66	46.33	17.32	100
46	1.04	1.04	5.90	25.00	51.73	15.28	100
47	2.30	3.45	4.31	23.57	47.13	19.26	100
48	1.12	1.12	3.59	20.63	61.88	11.67	100
49	3.79	2.45	3.79	22.04	47.88	20.04	100
50	1.29	2.58	4.23	17.85	60.20	13.81	100
51	1.75	0.79	3.65	17.77	63.80	12.22	100
52	1.75	1.32	2.63	16.67	62.28	15.35	100
53	0.58	1.31	3.34	18.60	54.06	22.08	100
54	0.75	0.50	3.01	16.68	51.71	27.36	100
55	0.49	1.97	2.92	15.59	53.10	26.92	100
56	0.27	0.82	0.95	19.61	57.89	20.43	100
57	1.20	0.72	2.65	16.00	53.42	25.98	100
average	1.28	1.63	4.23	19.84	54.86	17.88	

Year	3 Year Moving Average of Percentage over 50m	25-50m	10-25m	1-10m	less than 1m	Unprofitable
1943						
1944	2.09	1.61	7.48	23.54	52.62	12.61
45	1.72	1.04	7.72	24.84	49.47	15.15
46	1.78	1.83	5.95	24.73	48.39	17.23
47	1.49	1.87	4.60	23.06	53.58	15.49
48	2.40	2.34	3.89	22.03	52.29	16.99
49	2.06	2.05	3.87	20.17	56.65	15.17
50	2.27	1.94	3.89	19.22	57.29	15.35
51	1.59	1.56	3.50	17.43	62.09	13.79
52	1.36	1.14	3.20	17.68	60.09	16.55
53	1.02	1.04	2.99	16.48	56.91	21.69
54	0.61	1.26	3.09	16.12	52.95	25.45
55	0.50	1.10	2.29	16.44	54.23	24.90
56	0.65	1.17	2.17	17.06	54.89	24.44
57						

Source: J. Ben Carsey & M.S. Robert
Bulletin of the American Association of Petroleum Geologists, June 1963.

percentage of wildcat wells drilled in 17 states in the year. Since this shows no definite trend, the percentages were averaged over three years (part 3 of the table). It is difficult to detect a trend. There is stability in the shape of the distribution, rather than stability of individual parameters. The percentage of unprofitable and smaller wells has increased, although the incidence of the real bonanza wells (over 50 million barrels) seems as erratic as it ever was.

A tentative conclusion from this is that the resource base has been systematically eroded by past exploration. Technological improvements may keep the success rate high or push it higher, but this requires deeper wells, which are more costly than shallower ones, and the percentage of smaller size fields may be increasing, reducing the potential yield.

C. The Equilibrium Approach

In applying the equilibrium approach, it is assumed that businessmen, as rational profit maximizers, will maintain stocks of capital which maximize the overall profitability of their firms. This means that additional profit earned from buying an additional input of capital must be at least equal to the return from spending the same amount on any other input. This leads to the conclusion that the stock of capital maintained will be such that the marginal productivity of the capital input will be equal to the quantity:

$$\frac{\text{"user" cost of capital stock}}{\text{price of output}}.$$

The term "user" cost of capital refers to the implicit price the firm must pay in return for one unit of capital services. Under competitive conditions, a firm will adjust its stock of capital as conditions change so as to maintain this marginal equality. The relationship between the stock of capital held at various points and the values of price, user cost of capital, and production level imply the quantitative importance of each of the latter factors in influencing the stock of capital. This approach was here pursued, utilizing the annual figures for reserve stocks for the United States and Canada, average field prices in constant dollars, Aaa bond rates, and estimated finding costs.*

The problems in developing quantitative estimates are numerous. First, and perhaps most important, rational operators are basing decisions not on past values of variables, but on their expectations of future values. There is considerable evidence, of course, that historical data is commonly used as the basis for forming expectations of what future values will be; but, in trying to develop quantitative results, one must explicitly consider just how these expectations might be formed.

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*Petroleum Outlook, September, 1964, p. 158.

Another potential problem in utilizing empirical data is that the observations may represent transient, rather than equilibrium, conditions. This is particularly true if changes in the causal variables have been frequent, since subsequent changes may have occurred prior to restoration of equilibrium following these original changes. Consider, as a particular example, the case of a change in the field price (in real terms) of crude. The long-run reaction to a price increase (that is, a true price increase, which must represent a permanent shift in the demand schedule, since otherwise a price increase would cause a decrease in demand) would be an increase in reserve stocks, due to increased profitability; but the immediate reaction would be a decrease in reserves, since a price increase would serve as an incentive to increase current output.

The final major problem in this approach, one common to all time-series analyses, is the question of the stability of technology during the period studied. If, in fact, the quantity of reserves technologically necessary to support a certain level of output has changed during the period of study, it will cause errors in the quantitative relationships estimated. While there is evidence that such a change occurred, there exists some evidence as to the direction and magnitude of that change, thus making it possible to at least estimate its effect on the relationships.

1. Data Utilized

The relationships determined here were based on combined United States and Canadian reserves and production. The justification for this is based on both logical reasoning and circumstantial evidence. Figure A. 5 presents part of the circumstantial evidence. Examination of the United States-only reserve/production ratio indicates that it has been gradually declining, while the Canada-only ratio has been rising. For both of these to be due to rational decisions on the part of firms, either the expectation must be that Canadian production will be rising much more rapidly than United States production, or the firms involved consider the United States and Canada as a single market. The latter seems intuitively more plausible, particularly in light of the fact that United States firms control much of the Canadian reserves.

The individual producing firm should want to hold its reserves wherever holding them is least expensive, since the United States market can be supplied as readily from, say, Venezuelan crude as from domestic crude. Since the evidence indicates that foreign crude can be delivered to a United States coastal refinery at about $1.25 less than domestic crude, an individual producer might <u>prefer</u> holding foreign reserves to holding domestic reserves, since (all other things being equal) the expected return from foreign reserves will exceed that from domestic reserves. But import restrictions imposed by the Mandatory

Oil Import Control Program on March 10, 1959, effectively limit crude imports to 12.2% of domestic crude production. Thus, a firm with both domestic and foreign reserve holdings cannot anticipate supplying more than 12.2% of its share of United States domestic market demands from its foreign crude holdings. It is therefore unlikely that producers will consider foreign reserves as perfect substitutes for domestic reserves, even though in terms of total operations they may favor development of foreign reserves to development of domestic reserves because of the greater profitability associated with the former.

This situation would logically lead to an increase in the relative importance of the foreign operations of those United States producers whose size and economic strength permit them to operate freely in foreign countries. In terms of evaluating reserve levels, however, the import restrictions effectively prevent foreign reserves from "supporting" United States domestic demands. On the other hand, if domestic production were to be unavoidably restricted at some point, import restrictions would probably be eased; and the large producers may well be considering this possibility in making their decisions as to where to expend exploration and development effort.

Canadian (and Mexican) crude, however, is exempt from the allocation and licensing requirements of the Oil Import Control Program and, consequently, can serve as a substitute for domestic reserves for the individual producer.

For natural gas, the question of relevant markets seems even clearer. Canada supplies approximately 3% of United States consumption and the volume of these imports is growing, while the only other imports are a small amount from Mexico. Because there are no direct import restrictions on natural gas, the above-described problem does not arise.

Crude prices were taken from API data published in Petroleum Facts and Figures* and adjusted to constant 1965 dollars using the wholesale price index for all commodities other than farm and food. Natural gas prices are based on U.S. Bureau of Mines data, adjusted to 1965 dollars.

The basic data on finding costs is that presented in a summary statement in Petroleum Outlook, September, 1964. The time series presented here was extended to include 1964 and 1965 by computing the reserves found per dollar spent for exploration and development from the JAS survey data and API reserve figures.

The definition of finding cost is perhaps the most ambiguous area in the data in this study. There are three primary reasons for this.

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*"Average Price Per Barrel of Crude Oil at the Well," based, in turn, on Bureau of Mines reports.

First is the question discussed in Section IV.B concerning the measurement of reserves actually discovered. Although the API definition of reserves is used consistently throughout this study, it seems obvious that any producer, in making decisions to explore, is contemplating a discovery of reserves in excess of the API-defined reserves. In the type of model here proposed, the relevant variable is the operator's expectation.

Second is the relatively poor data available on actual costs of exploration and development activity. Such data have been collected only sporadically, with little breakdown by category of expenditure.

The third reason is that a discovery is of itself a random event, and the barrels found per dollar may be expected to fluctuate considerably from period to period in the absence of any real change in the efficiency or cost of exploration. It is hardly plausible, then, that operators would use, for example, the most recent experience as the basis for estimating the finding costs that will be incurred from current operations. High observed values of finding cost represent, at least partly, a period of comparative lack of success in exploration activity, and low observed values represent a period of relative success. Consequently, an operator's expectation of finding costs for his current operations should be represented by some averaging of recent costs.

Production figures used were obtained from API reports based on Bureau of Mines summary statistics for United States data and from Canadian Petroleum Association reports for Canadian data. The raw data for these values are quite reliable, but there is again some question as to how the expectations of operators might be related to reported production figures. The production level observed in any one year is subjec to some random fluctuations and is not necessarily a good forecast of what future production levels will be. The demand for crude in particula although rising by 40% from 1953 to 1966 (an average annual increase of 2.6%), has risen by as much as 8.1% and has decreased by as much as 6.8% from one year to the next. In this situation, it seems again reasonable to utilize some sort of averaging to forecast future production requirements.

D. The Simulation Approach

Another general approach to determination of reserve responses to tax-policy changes is to (a) identify significant variables which, theory would indicate, affect reserves and (b) determine the effect of tax-policy changes on these variables. This approach requires no assumptions that operators are true profit maximizers but, rather, depends on empirical observations to determine operators' responses to changes in the variables. Models of this class take the observed state of the world as given, and then develop empirically observed relationships which indicate expected responses to changes in certain variables. In contrast to neoclassical economic models, the explanatory variables in such a model may be those which bring about effects only indirectly, since no attempt is made to provide a complete theoretical foundation for the model. Such models have been increasingly popular in recent years, primarily due to their success in explaining anomalies in observed behavior which are clearly inconsistent with economic theory.

Previous investment models of this type have frequently used the preceding year's rate-of-return as a determining variable in explaining investment. Leaving aside for the moment the question of correctly measuring a rate of profit, this possibility will be discussed.

For any businessman, it is the expectation of future profits which guides investment. This suggests that businessmen may be more influenced by their long-term view of the place of their industry in society than by last year's or the previous years' profit rates. The armaments manufacturer who sees an armistice approaching will not be guided by high wartime profit in determining his level of investment in the coming period of peace. Similarly, if the oil industry becomes convinced that the long-term prospects in oil are poor, expansion may slow down and retraction may occur. Since investment involves tying up assets over a long period, to induce a change in investment policy is likely to require a longer-term trend than would be reflected in a single year's realized profit rate.

In neoclassical economic theory, the rate of profit is not a determinant of investment, but a result of investment. Thus, any industry which has a current rate of return higher than that for investment in general is suffering from under-investment, with the reverse true for industries offering less than market rates. Under-investment or over-investment may have resulted from a shift in demand and/or from the existence of market imperfections which restrict free entry and exit.

On the other hand, there are plausible reasons why the rate of profit of the previous period could be considered a determining variable for investment. For an industry which has an established and fairly stable demand, the present rate of profit is perhaps a good estimate of the future rate of profit, and it is likely to be the figure on which expectations are based. A good current rate of profit will also indicate that funds are available for investment, both because outside capital can be attracted to profitable companies and because high profit generally leads to high net cash flow. Whether the internally generated cash flow available to a company through retained earnings and tax allowances is a significant factor in investment will depend on how far the company is able to take advantage of the capital market. Very small companies may find the market unwilling to lend, while very large companies may find themselves in a position where the extent of their demand for borrowed funds raises the rate of interest against them. In either of these cases, internally generated funds would have a lower supply price than funds borrowed on the market.

Another explanatory variable is change in demand. The technological rationale for this is that, if demand for a product increases during any period, increased production may strain plant and equipment to capacity, and costs may begin to rise. In such a case, investment is required to bring the labor and capital inputs back into balance, particularly if the higher demand is taken to be permanent. Empirical work on investment in manufacturing industry suggests that change in demand may be at least as significant as the rate of profit in determining investment. Stigler* derives a multiple correlation between investment and the previous period's profit rate and change in demand, using data for 98 industries and eight years. The results suggest that demand is the more important variable. However, when there is introduced a correction factor for price changes, the importance of the profit rate increases, suggesting that demand and investment are subject to the same inflationary factors.

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*G. J. Stigler, Capital and Rates of Return in Manufacturing Industry, National Bureau of Economic Research, Princeton, New Jersey, 1963.

Still another variable suggested as a determinant of investment is internal cash flow. The rationale for this is the firms' investment budgets are based on the funds available, and that there is general unwillingness on the part of managers to resort to outside financing, due perhaps both to the effort involved (particularly for the smaller firm) and to the possibility of sacrifice of control which outside financing entails. A number of studies have been made in which these factors were significant.*

E. Quantitative Analysis of Expenditures for Exploration and Development

In order to develop a function to estimate expenditures for exploration and development, it was necessary to examine in as much detail as possible the patterns of these expenditures over the past years and to relate these patterns to the patterns of possible determinants of expenditures such as demand or profit.

The longest series of data on expenditures is published by Chase Manhattan Bank and is available for consecutive years from 1946-1965. The data divides the domestic United States petroleum industry into two groups: The Chase group, which is composed of between 30 and 33

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*E.g., W. Heller, "The Anatomy of Investment Decisions," Harvard Business Review, 29, No. 2, March, 1951.

large, integrated companies, and the Other group, which is a heterogeneous collection including some large integrated firms as well as individual operators. The Chase Manhattan data does not give separate estimates of exploration and development expenditures, nor is it a true division by size of company. The Chase group varies slightly in composition, but it may be assumed to be representative of the largest companies. The heterogeneous nature of the Other group makes any generalizations about its behavior subject to several qualifications. The pattern of expenditure for each group and the total industry will be considered first, then the related patterns of production and several rate-of-return measures.

1. Expenditures for Exploration and Development

The expenditures for exploration and development for each group and for the total industry are shown in Table A. 9 and Figure 6. 1. Figure 6. 1 gives a clear picture of the pattern of these expenditures over the past twenty years. The expenditures for exploration and development for each group and for the total rose sharply from 1948 to 1957. At this point in time, there is a definite break and the two groups diverge to distinctly separate paths. After an initial but sharp drop in 1958, the Chase group continues a general path of rising expenditures for exploration and development. The Other group, after a similar

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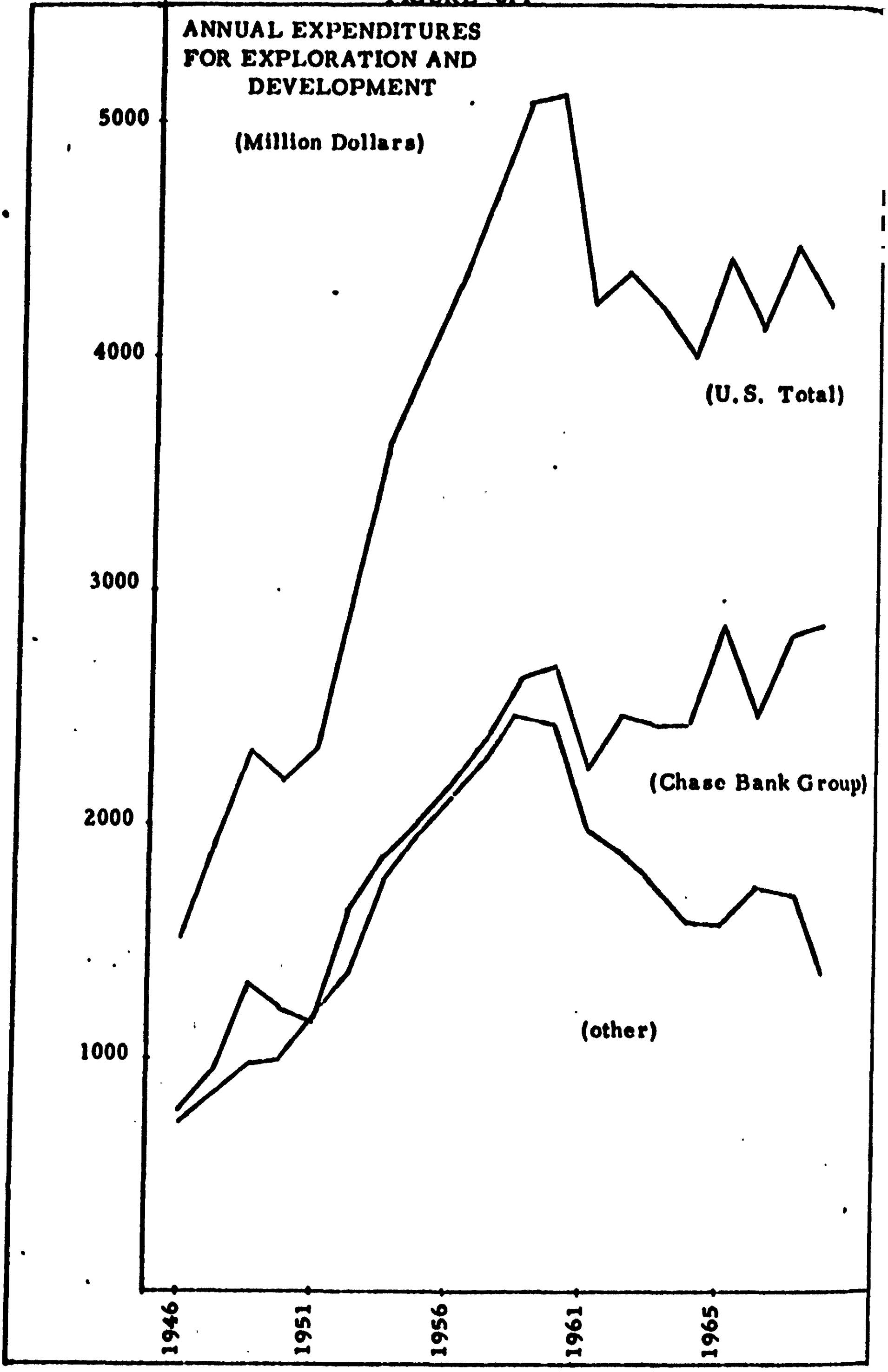
FIGURE 6.1


ANNUAL EXPENDITURES
FOR EXPLORATION AND
DEVELOPMENT
(Million Dollars)
5000
4000
3000
2000
1000
(U.S. Total)
(Chase Bank Group)
(other)
1946
1951
1956
1961
1965

sharp drop in 1958, does not by contrast recover, and enters a steady but continuing period of decline in exploration and development expenditures. The decline in the expenditures for the Other group is severe enough to affect the total industry, which shows a decrease from 1957 to 1965.

In summary, the annual expenditures by the Chase group started at $775 million in 1946, rose to a peak of $2673 million in 1957, declined for the next few years, but finally more than recovered, reaching $2817 and $2847 million in 1964 and 1965, respectively. The Other group had expenditures of $740 million in 1946; these rose to a peak about 1957 when they reached $2427 million, and then declined steadily to a low in 1965 to $1363 million. The total expenditures for the industry followed somewhat the same pattern: expenditures of $1515 million in 1946; a peak of $5100 million in 1957; a decline and partial recovery to $4450 million and $4210 million in 1964 and 1965, respectively. Two points are obvious from these data. First, the industry structure and pattern of expenditures changed in 1957 or thereabouts, with one pattern being exhibited prior to this time, and a second totally different pattern between exhibited after 1957. Second, there are at least two distinct segments of the industry with quite different patterns of expenditures for exploration and development. These facts will make it hazardous to use the past behavior of the total industry (over the last twenty years) to judge possible behavior of the industry in the future.

The relevant patterns of expenditures can be more readily seen in Figure 6.2, which is derived from Table A.15. The expenditures for each group and for the total industry were summed over an eight-year period to synthesize an asset base for the industry. From the graph (Figure 6.2), it can easily be seen that the assets in exploration and development increased for both groups from 1953 to approximately 1958 or 1959. After this time, the Other group decreased such expenditures at a steady rate, while the Chase group continued to increase theirs but at a slower rate. The total industry reflects the decline experienced by the Other group.

2. Production and Gross Income

The output and gross income of the groups are shown in Figures 6.3 and 6.4, and in Tables A.1 and A.8. Again, two distinct patterns occur. The Chase group begins in 1946 with an annual production of 1270 million barrels and increases its production to a temporary peak in 1957 of 1637 million. The production then declines for about two years and finally increases to 1923 million barrels in 1965. The Other group starts at 749 million barrels in 1946, increases to 1004 million in 1956, and then declines to a low of 925 million barrels in 1965.

FIGURE 6.2

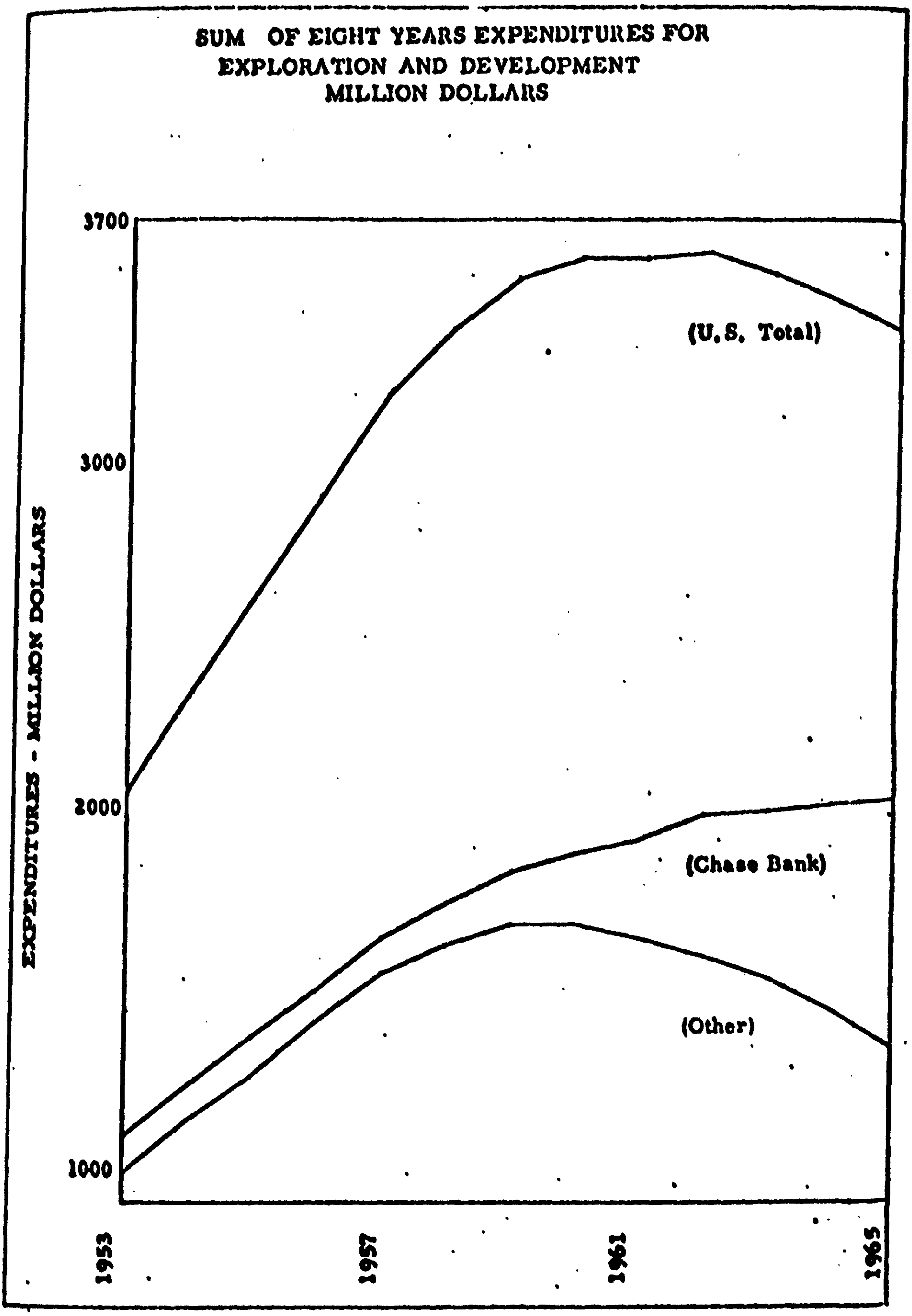

SUM OF EIGHT YEARS EXPENDITURES FOR
EXPLORATION AND DEVELOPMENT
MILLION DOLLARS
3700
3000
2000
1000
EXPENDITURES - MILLION DOLLARS
(U.S. Total)
(Chase Bank)
(Other)
1953
1957
1961
1965

FIGURE 6.3

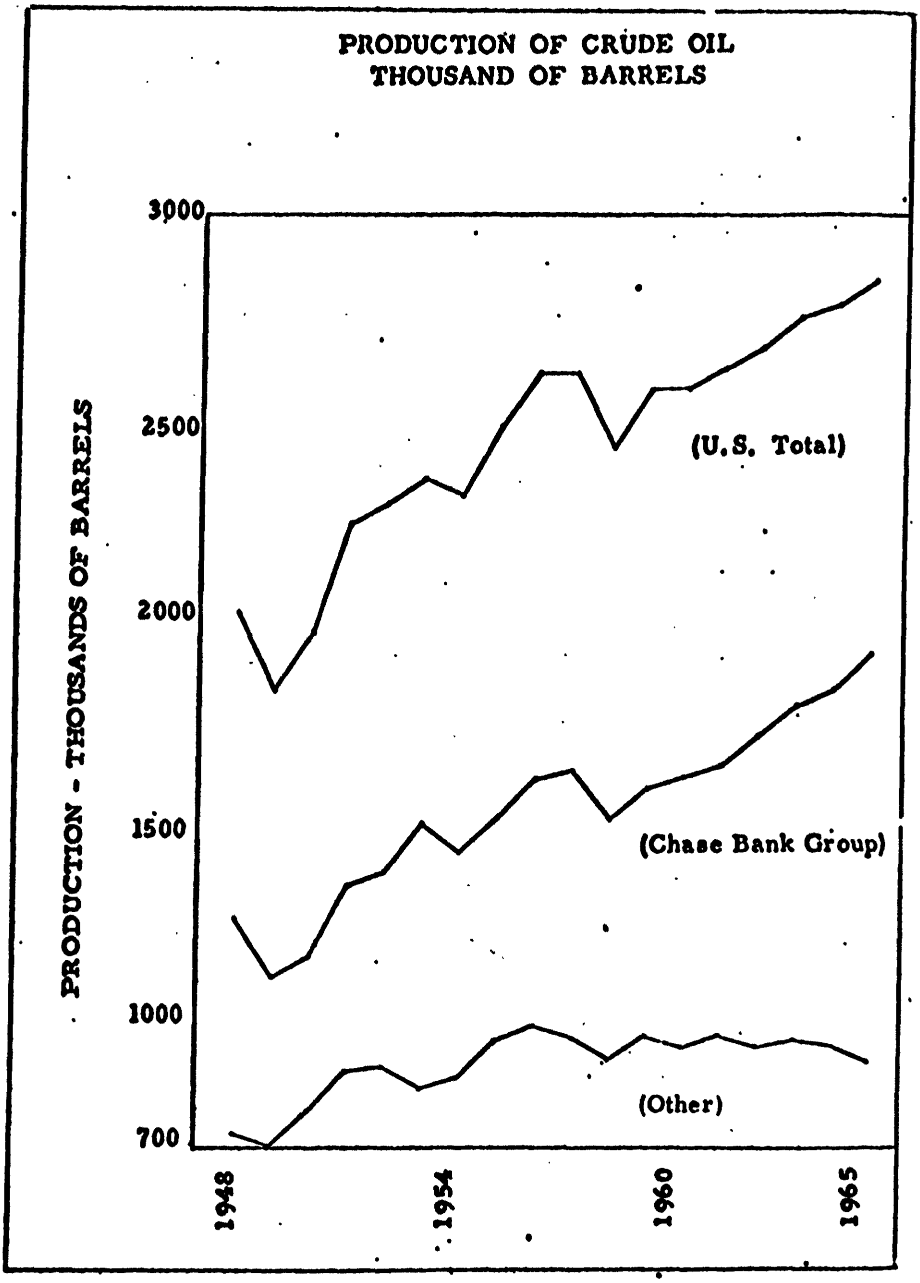
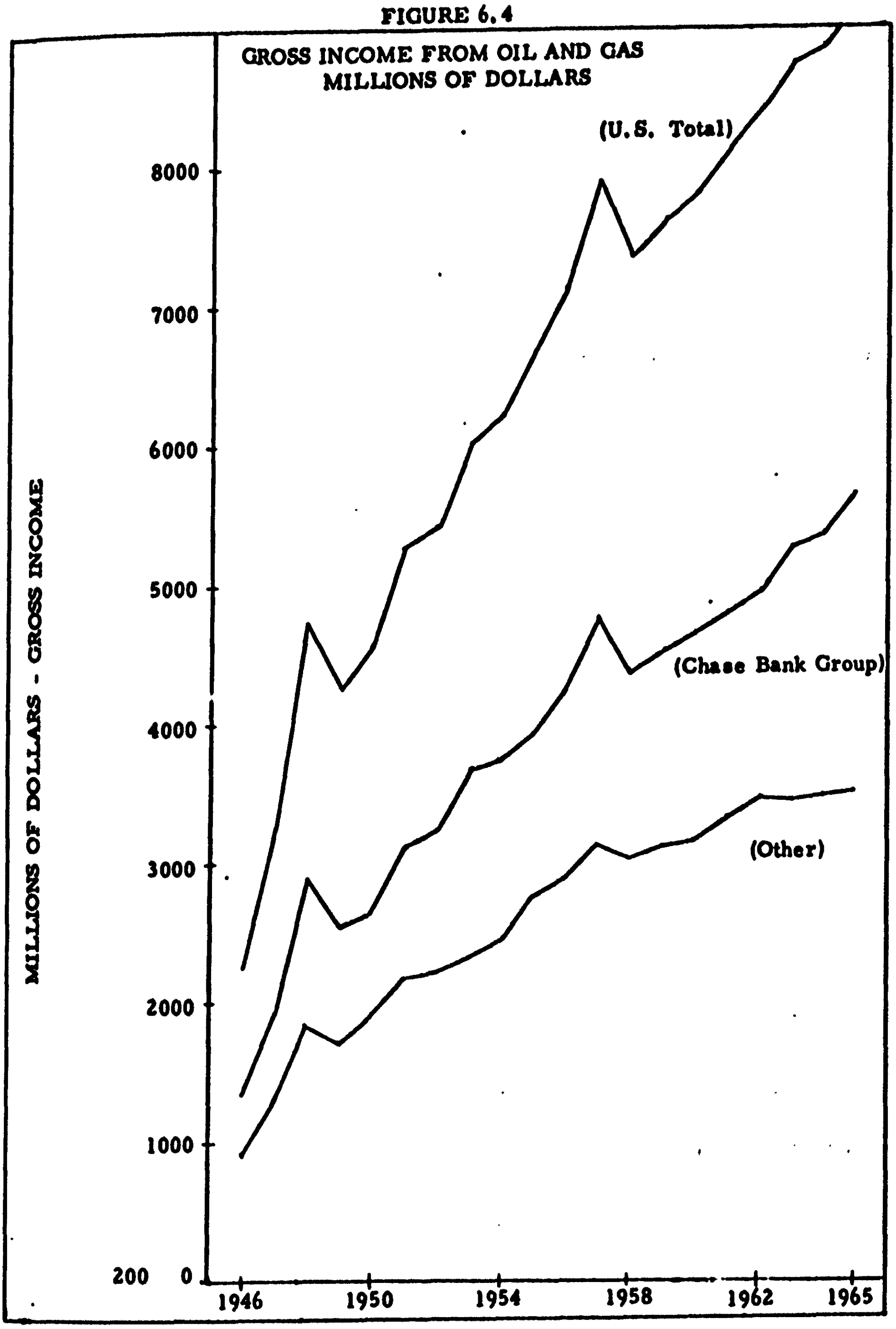

PRODUCTION OF CRUDE OIL
THOUSAND OF BARRELS
PRODUCTION - THOUSANDS OF BARRELS
3000
2500
2000
1500
1000
700
(U.S. Total)
(Chase Bank Group)
(Other)
1948
1954
1960
1965

FIGURE 6.4


GROSS INCOME FROM OIL AND GAS
MILLIONS OF DOLLARS
(U.S. Total)
(Chase Bank Group)
(Other)
MILLIONS OF DOLLARS - GROSS INCOME
8000
7000
6000
5000
4000
3000
2000
1000
200
0
1946
1950
1954
1958
1962
1965

The increased production in 1956 and 1957 are probably due to the increase in demand caused by the Suez Crisis. The industry appears to have successfully met this increased demand without an apparent change in the pattern of expenditures.

The important pattern to note here is that the Chase group has absorbed all the increase in demand in the years since 1959, while the Other group has experienced a steady but (apparently) slowly decreasing production level, particularly in the last two or three years.

The wellhead value of oil and gas production (minus fifteen percent for royalties) is used as a measure of gross income for the two groups. This measure has shown a steady increase for both groups since 1946, with few exceptions, notably the drops after the Korean War and the Suez Crisis. Table A.1 and Figure 6.4 show a slower rise in gross income for the Other group than for the Cahse group, especially since 1958. During this latter period, gross income for Chase rose by 29% while gross income for the Other group rose by 17%.

A more interesting question is how the Other group managed to increase income while reducing expenditures for exploration and development. There appear to be two reasons for this. First, the Other group has managed to keep production fairly high. While, from 1957 to 1965, the Other group reduced expenditures for exploration and development by 44%, production during the same period declined by only 13%. This process is reasonable. While it may be not profitable to explore or develop <u>more</u> oil, it may well be profitable to continue to produce from presently owned wells. A producing oil well is an extremely durable asset, one with an average life of about 25 years, and the initial estimates of recoverable oil from some wells are still being revised as long as 40 years after discovery. Thus, production might decline fairly slowly for some years after exploration and development effort was reduced.

A second reason may lie in the portion of gross income which does not come from crude oil production but, rather, from gas production, lease revenue, and royalty payments received. These sources, particularly lease and royalty payments, could be forming a larger portion of the gross income of the Other group.

3. Estimates of Rates of Return and Expenditures

In principle, the simulation model aimed to base predictions on past responses to realized rates of return. This is the function of the modeling approach, and considerable effort was expended in developing a workable estimate of rate of return.

The only published source available for estimating rate of return to assets is Corporation Tax Returns,* but it does not indicate the return to assets in domestic production of crude oil and natural gas because:

(1) No distinction is made between domestic and foreign activities.

(2) No distinction is made between assets used in refining and those used in crude oil production; nor is gross income so divided.

(3) Calculation of an asset base is further confused because:

(a) Depreciation allowances no longer reflect in principle the consumption of capital.

(b) Depletable assets reflect not discovery value, but the remaining depletable assets account.

(c) The special provision to expense exploration and development expenditures underestimates the asset base.

Mr. Simon M. Simon of New York University kindly made available his calculation of rate of return on assets in the crude oil and petroleum refining industries for 1946-1961. These estimates attempt to correct for all the factors listed under (3), following the practice of Stigler.** These are shown in Table A.17.

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*Statistics of Income, U.S. Treasury Department.

**Stigler, G., Capital and Rates of Return in Manufacturing Industry, National Bureau of Economic Research, Princeton, New Jersey, 1963.

The table also shows Stigler's own estimates for rate of return to petroleum refining and estimates prepared from data on a sample of large firms published by the First National City Bank. These estimates all include foreign returns. This is not a negligible factor, since there has been a shift to foreign production which, as far as can be ascertained, is more profitable than domestic production.

The estimates all follow a roughly similar path, but the disparity of magnitude is considerable. Table A. 18 gives comparative data from the same sources for rate of return to various other industries.

It was evident that these rates of return would not serve as predictors for the model, and it became necessary to develop a variable to satisfy the needs of this study. The first requisite of such a variable was that it is predictable, i.e., that it be constructed from other known or previously predicted measures in the model. Second, it was necessary that it predict expenditures reliably.

A commonly used rate-of-return formulation is gross income minus operating expenditures divided by assets, as follows:

$$\frac{\text{Gross Income} - \text{Operating Expenditure}}{\text{Assets}}$$

Not all these variables are known for the portion of the industry which finds, develops, and produces crude oil. Hence, some had to be estimated.

Gross income was defined as gross income from the sale of oil and gas minus 15% royalties plus small amounts from lease revenue and royalties received. Operating expenditures were estimated from production and the price of crude oil. *

Since assets result from past expenditures, an initial estimate of the assets committed to crude oil production activity was obtained by summing three years' expenditures for exploration and development (the past two years' and the present year's). The data for these variables is shown in Table A.2.

Using these variables, a rate of return was computed according to the following equation:

$$\text{Rate of Return}(t) = \frac{\text{Gross Income}(t) - \text{Operating Expenditures}(t)}{\text{Sum of Three Years' Expenditures for Exploration and Development } (t, t-1, t-2)}$$

This rate of return was calculated for the Chase group, the Other group, and the total industry. The results can be seen in Table A.3 and in Figure 6.5.

For both sections of the industry, the rates of return drop sharply from a high in 1948 to a low point in 1958. However, there are major differences in the total patterns over the entire twenty years.

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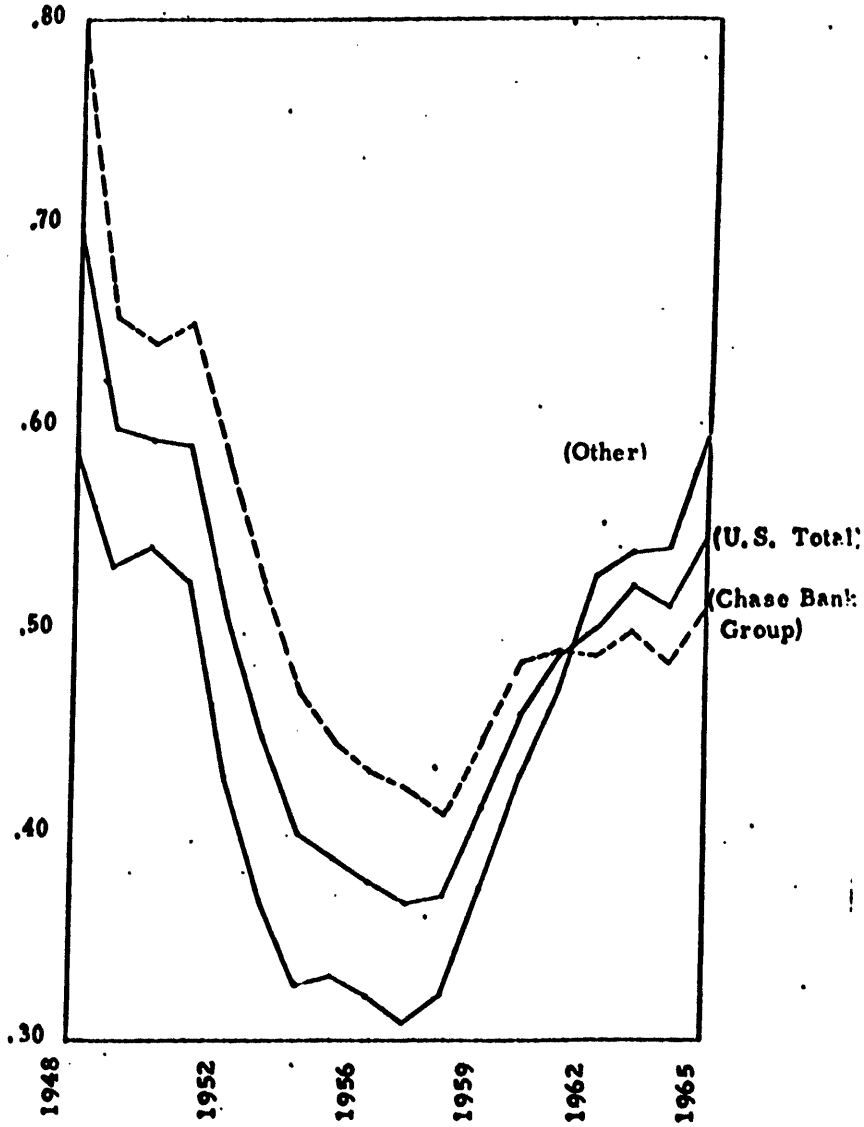
*See page C.15.

FIGURE 6.5
RATE OF RETURN BASED ON SUM OF THREE YEARS EXPENDITURES FOR EXPLORATION AND DEVELOPMENT



The rate of return for Chase drops to its low in 1958. After this, it increases again until 1962 when it shows a tendency to increase but with an ascillating pattern.

The Other group drops from the 1948 high into a low period starting about 1954 and continuing to 1958. After 1958 the rate of return for the Other group rises sharply. The apparent reason for this is their reduced expenditures for exploration and development. (This point will be discussed in more detail below.)

It should be noted that, in the 1948 to 1957 period when both rates were falling, the rate of return to the Other group was considerably lower than for the Chase group.

The purpose of computing this rate of return was to determine whether this measure could be used as a determining variable from which to estimate expenditures for exploration and development. It can be seen from the data that these two measures do not follow any similar pattern. In fact, they appear to follow opposite trends. This can be seen most clearly in Figures 6.6, 6.7, and 6.8, where this estimate of rate of return and expenditures for exploration and development are shown together.

These patterns are open to several interpretations. Since expenditures for both groups have risen in the face of falling profit rates, it

FIGURE 6.6
U.S. DOMESTIC PETROLEUM INDUSTRY
U.S. TOTAL

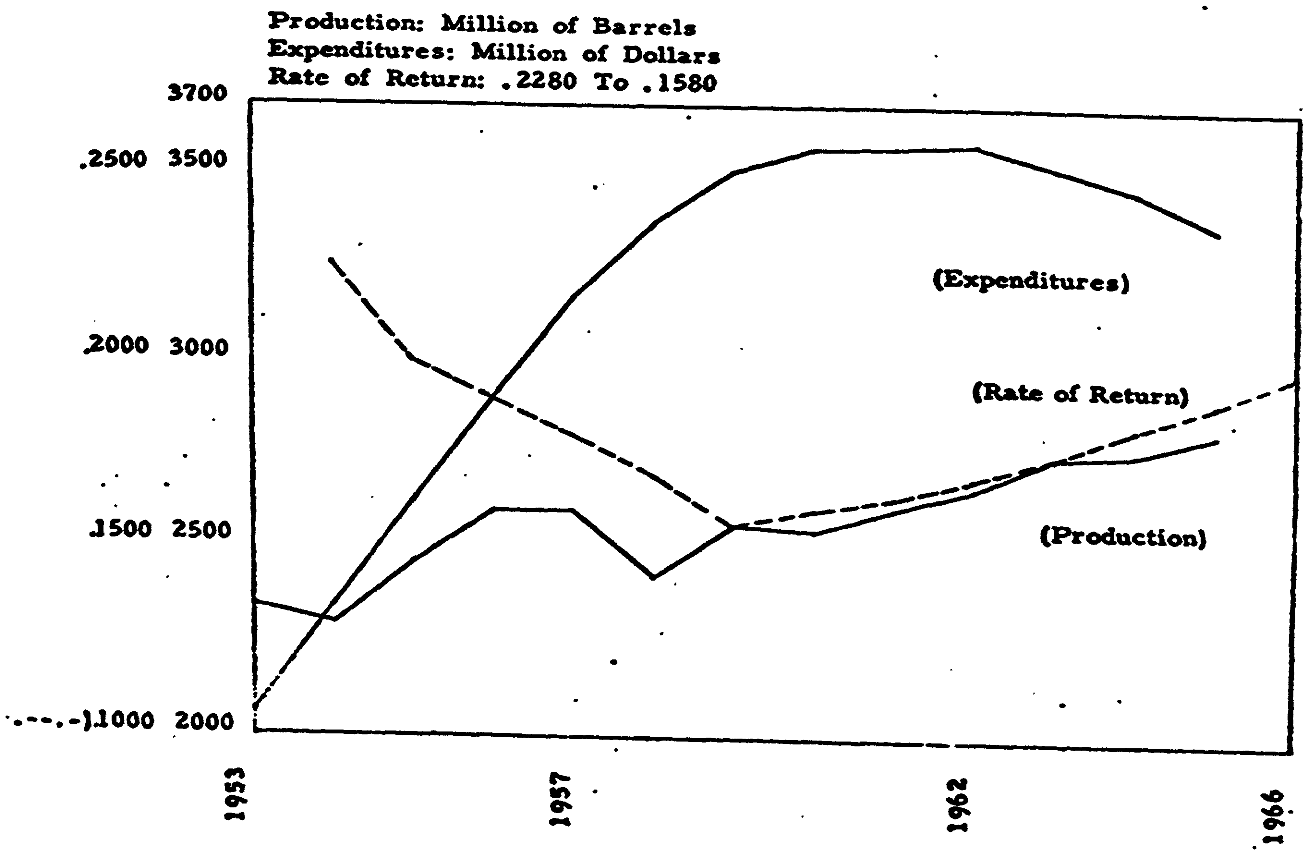


FIGURE 6.7

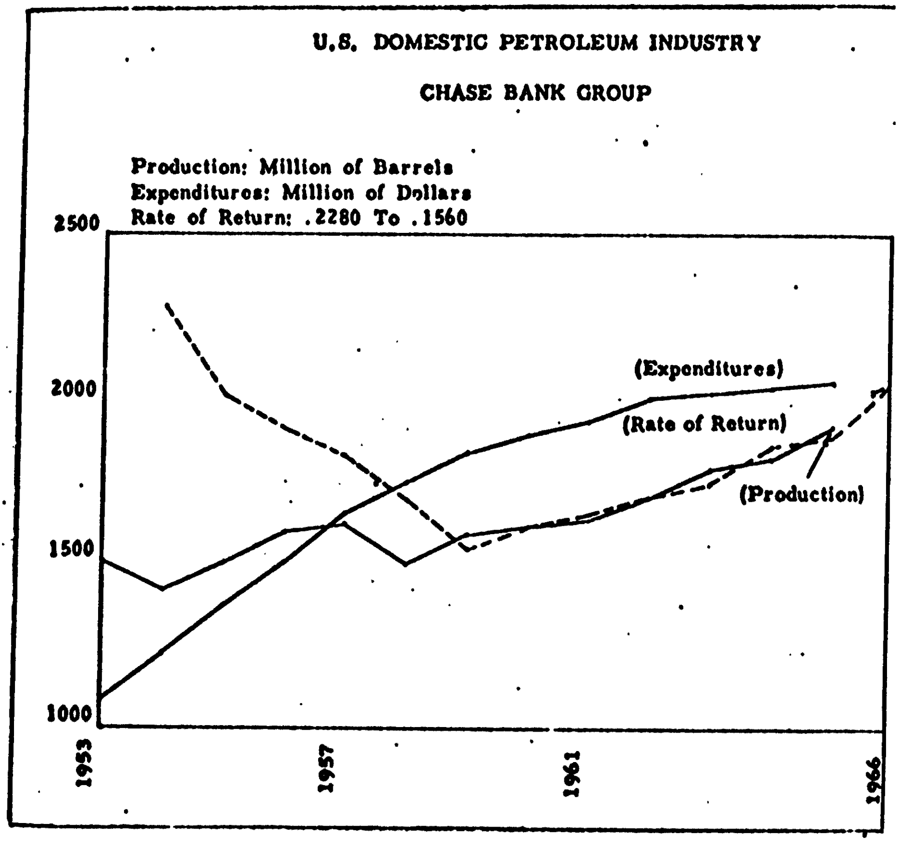
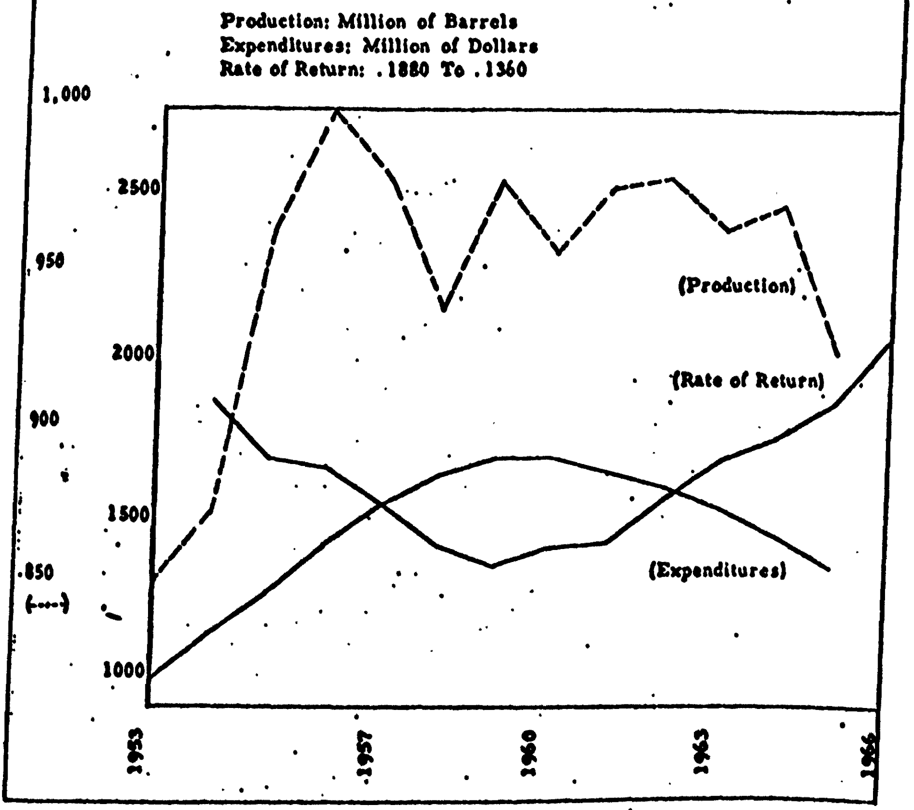

U.S. DOMESTIC PETROLEUM INDUSTRY
CHASE BANK GROUP
Production: Million of Barrels
Expenditures: Million of Dollars
Rate of Return: .2280 To .1560
2500
2000
1500
1000
(Expenditures)
(Rate of Return)
(Production)
1953
1957
1961
1966

FIGURE 6.8

U.S. DOMESTIC PETROLEUM INDUSTRY

OTHER GROUP



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is possible that the industry was making excess profits, either because of market imperfections and entry restrictions, or because the rate of return was still tending to long term equilibrium. It would be expected that the rate of return would continue to fall until it reached an equilibrium level in competition with other industries, when marginal produce would leave the industry or at least not expand. (See Figure 6.5)

This appears to be the path followed by the Other group. The rate of return declined for several years until it stabilized at its lowest value for a period of about five years. At the end of this sustained period, the Other group began reducing expenditures for exploration and developmen but continued to receive income from past expenditures because the average life of an oil well is fairly long, at least as long as the period in which the Other group had been reducing investment in exploration and development.

The Chase group also experienced a decline in the rate of return from 1948 to 1958, but their rate never reached the low levels that the Other group experienced. There was also no stabilizing period, since the rate of return reversed its trend and started to rise from 1958 to 1965.

It could thus tentatively be concluded that for the Other group, which is heterogeneous group composed of small operators and companies, as well as a few large firms, the industry has already passed the point where marginal explorers have preferred to leave. In fact, this point occurred about ten years ago.

These conclusions were stated as tentative because several objections could be raised. It could be argued, first, that investment is a function of a lagged rate of return; second, that investment is not a function of the rate of return but of the absolute return (that is, absolute profit); or third, that it is not valid to expect expenditures to be a function of the rate of return when the industry in a period of readjustment and, therefore, that only a portion of the twenty-year period should be used. These possibilities were investigated.

The levels of expenditure for exploration and development were estimated as a function of the lagged rate of return for up to five years. (The lagged variables were tried individually as well as all five lagged variables together.) This was done for the Chase group, the Other group, and the Total. Equations in logs of all the variables were also calibrated. This effort produced no useful results. When the variables were used singly, the correlations were either negative or produced R^2's in the neighborhood of .02. When the lagged variables were used together, the R^2's were in the neighborhood of .40 but the standard errors of the coefficients were more than twice the values of the coefficients, indicating that the latter are not reliable.

The estimating equations that were tried are listed below:

Let RoR = Rate of Return (as defined above)

TEP = Expenditures for Exploration and Development

GIN = Gross Income

EPPR = Production Expenditures

STEP = Sum of Three Years Expenditures for Exploration and Development

then
$$RoR(t) = \frac{GIN(t) - EPPR(t)}{STEP(t)}$$

The equations used in the analysis are:

$$TEP(t) = a_1\ RoR(t-1)$$

$$TEP(t) = a_1\ RoR(t-2)$$

$$TEP(t) = a_1\ RoR(t-3)$$

$$TEP(t) = a_1\ RoR(t-4)$$

$$TEP(t) = a_1\ RoR(t-5)$$

$$TEP(t) = a_1\ RoR(t-1) + a_2\ RoR(t-2) + a_3\ RoR(t-3) + a_4\ RoR(t-4) + a_5\ RoR(t-5)$$

$$\log_{10} TEP(t) = a_1 \log_{10} RoR(t-1)$$

$$\log_{10} TEP(t) = a_1 \log_{10} RoR(t-2)$$

$$\log_{10} TEP(t) = a_1 \log_{10} RoR(t-3)$$

$$\log_{10} TEP(t) = a_1 \log_{10} RoR(t-4)$$

$$\log_{10} TEP(t) = a_1 \log_{10} RoR(t-5)$$

$$\log_{10} TEP(t) = a_1 \log_{10} RoR(t-1) + a_2 \log_{10} RoR(t-2) + a_3 \log_{10} RoR(t-3) + a_4 \log_{10} RoR(t-4) + a_5 \log_{10} RoR(t-5)$$

The next estimating equation analyzed was based on the theory that expenditures for exploration and development were a function of the absolute profit or return, rather than the rate of profit. Therefore, the following equation was used:

$$TEP(t) = a_1 (GIN(t-1) - EPPR(t-1))$$

This equation was estimated using the nineteen-year data for each of the three groups: Chase, Other, and Total. The results produced, when the absolute return was used as the determining variable for exploration and development expenditures, were the same as for the above equations, that is, either negative or statistically unreliable. This was true for all three groups.

4. Estimating Equations Based on the Period 1957-1965

Finally, several alternative measures were tried for the Chase and Total groups for 1957-1965, a period felt to reflect present trends. (It is obvious that there is no reason to attempt any further analysis for the Other group for this period.)

For this period (1957-1965), the expenditures were estimated as a function of rate of return, return only (that is, absolute profit), and rate of return based on annual expenditures, as opposed to the sum of three years expenditures. These profit measures were all lagged by one year.

The analysis of the Total group revealed no significant relationships between the level of expenditures for exploration and development and any of the three return measures. The analysis on the data regarding the Chase group revealed that some weak relationship may exist between the expenditures for exploration and development and some of the measures of return. The expenditures estimated from the rate of return based on the sum of three years expenditures yielded an R^2 = 0.3776; based on return only (absolute profit) R^2 = 0.5420. The logs of the variable produced R^2's in the same range. The standard errors of the coefficients of the variables were less than one half their value. When expenditures are estimated on the basis of a rate of return computed on annual expenditures, the results are improved. The R^2 for this equation is 0.5685 and the coefficients of the variables are more reliable.

The equations used were:

$$TEP(t) = a_1 \, RoR(t-1)$$

$$TEP(t) = a_1 \, (GIN(t-1) - EPPR(t-1))$$

$$TEP(t) = a_1 \, RoR(t-1)$$

where the rate of return is computed using annual expenditures for exploration and development rather than the sum of three years expenditures for expenditures for exploration and development.

In summary, the data, graphs, and analysis indicate two major points:

(1) The industry has undergone major changes in its pattern of expenditure for exploration and development and its rate of return in the past twenty years.

(2) Over this twenty-year period, there is not a measurable relationship between the rate of return and the level of expenditures.

Analysis on the data for the period from 1957 to 1965 shows that there may be some relationship between the rate of return and expenditures for exploration and development for the Chase group. There is no similar relationship between expenditures and the rate of return for the entire industry.

An alternative source of data is the annual survey published by the Joint Association Survey. This organization collected data for the entire industry on expenditures for domestic exploration, development, and production separately. This data allows separate estimates to be made of expenditures for exploration and expenditures for development.

There are two difficulties in using the Joint Association Survey data. First, the breakout between exploration and development expenditures appears not to be precise. All expenditures resulting in successful wells are classified as development expenditures. All expenditures which resulted in dry holes are classified as exploratory costs. Since approximately twenty percent of development wells result in dry holes, some of the dry-hole cost should logically be allocated to development expenditures; a similar proportion of exploratory wells are successful and their costs should be allocated to exploratory expenditures. However while the classification of expenditures and their titles (that is, exploration and development) is perhaps unfortunate, it is not a serious problem if they are to be used as variables in an estimating equation. In other words, it is not important what the variables are labeled. What is important for this study is whether the use of the variables yields a reliable estimate.

The second problem is that the data is available consecutively only from 1959 to 1965 and for the years 1953, 1955, and 1956. This limits the number of points that can be used in any function, especially if the variables are lagged by time period. While this is inconvenient, especially for the missing years 1957 and 1958, the previous analysis has shown that it is the more recent years which should be most closely modeled, because of the apparent period of adjustment during the 1950's and because the later years are the only period indicating any sensitivity of expenditures to rate of return.

The estimating functions developed separately for expenditures for exploration and for development were based on the theory that continued expenditures in either exploration or development would depend upon:

(1) The profitability of total expenditures,

(2) The relative profitability of the particular kind of expenditures, that is, mainly exploration or development,

(3) The need to replace previous investment being currently consumed.

On this basis, the following functions were defined:

$$\text{(6.1)} \qquad EPEL(t) = a_1 \left(\frac{NP(t-1)}{TEP7}\right)^{a_2} \left(\frac{NRE(t-1)\ PR(t-1)}{EPEL(t-1)}\right)^{a_3}$$

$$\text{(6.2)} \qquad EPDV(t) = a_1 + a_2\ EPEL(t) + a_3 \left(\frac{NRE(t-1)\ PR(t-1)}{EPEL(t-1)}\right)$$

where EPEL = expenditures (mainly exploratory),

EPDV = expenditures (mainly development),

NRE = new reserves from exploration,

PR = price,

TEP7 = seven-year exponential moving average of total expenditures for exploration and development,

NP = net profit.

The first term, in both equations, is the ratio of the net profit to the total expenditures for exploration and development. The second term, in the case of the exploration equation, is the barrels of new reserves discovered through exploratory effort times the current price of crude oil, or a measure of the return from exploratory effort. This product is then divided by the expenditures which are mainly for exploratory purposes. Thus, the total ratio is a measure of the return from exploratory effort or the inverse of the finding cost of reserves.

The equation to estimate development expenditures is based on the best fit found, and bases development expenditure on exploration expenditure and the success factor of previous exploration expenditure. The fit of such an equation was significantly better than one based on the same factors as the exploration equation. The explanation may be simply that the availability of developable properties is a function of exploration. (In the calibration, the lagged exploration success accounts for $R^2 = 0.7159$ out of a total R^2 of 0.7329.

As noted previously, the breakout of expenditures between "exploration" and "development" is not to be regarded a precise allocation. Since expenditures resulting in successful wells are classified as "development expenditure" and expenditures which resulted in dry holes are classified as "exploratory expenditure," the ratio of values in the second terms of the estimating equations cannot be strictly interpreted as a return from exploration or development expenditures but only as a return from exploration or development effort if, indeed, any economic interpretation should be attached to them at all.

Net profit is defined as the difference between receipts from oil (and gas) production and expenditures for finding, developing, and producing oil (and gas), divided by the expenditures. The receipts include income from leases and royalty payments but exclude royalty payments made to others. The receipts from (oil and gas) production are determined from the gross value of all production after deducting fifteen percent for royalty payments. This variable is therefore an attempt to approximate the profit from finding and developing crude oil (and gas) without using data which involve profits resulting from refining or foreign properties. It is not, of course, a perfect measure, since not all costs or expenditures are included in the data available. The expenditures do not include income taxes, interest charges, and returns to investors.

Although it was felt that one of the final set of equations described above would yield satisfactory estimates, additional estimating functions were formulated. These were based solely on receipts which approximate demand.

These functions are:

$$EPEL(t) = a_1 + a_2 \, GIN(t)$$

$$EPDV(t) = a_1 + a_2 \, GIN(t)$$

In any of the above functions, the change in expenditures for exploration and development due to changes in the depletion allowance can be estimated by reducing the income or receipts by the amount of additional taxes which must be paid. The effect of changes in royalties can also be estimated by the same procedure. Thus, these functions could be used to determine if a change in depletion allowances might be compensated for by a change in royalty payments.

The operation of the model rests on the assumption that it is necessary to determine the profitability of expenditures in crude oil under alternative tax policies only with respect to its former conditions and that it is not necessary to determine its relative profitability with respect to all other industries.

It would, of course, be useful to determine its position relative to all industries, but substantial difficulties prevent the making of any meaningful comparisons. Only the most aggregate comparison between the entire petroleum industry (including refining and foreign) and other industries can be made, and even these comparisons are subject to criticism on several points.

A regression analysis was performed on the last two sets of investment functions described above, using data from the Joint Association Survey for the years, 1955, 1956, and 1959-1963. The statistical measures of the analysis (F ratios, standard error of the coefficients, and so forth) are presented in Appendix C. The regression program used provided a step-wise option which entered the variables in order of their explanatory power. In most cases, equations using the logs of the variables were also calibrated by regression analysis.

As would be expected from the theory discussed earlier, expenditures for exploration are more sensitive to the rate of profit than are expenditures for development, since exploration expenditures are more "postponable" than development expenditures. This result was true for all forms of the equations.

In summary, the analysis revealed that, over the twenty-year period from 1946 to 1965, no statistical evidence was found which would indicate any significant relationship between the numerous measures of rate of return calculated and total expenditures for exploration and development for the domestic crude petroleum industry. In addition, no relationship was found to exist when the industry was analyzed as two separate groups, namely, the Chase group and all Others.

Analysis over the more recent past (from 1958 to 1965) revealed no significant relationship between the rate-of-return measures and expenditures for exploration and development for either the total industry or the Other group. For the Chase group, the analysis showed at most a weak relationship between the measures of return and expenditures.

The analysis based on the breakout of expenditures for exploration and development into two classes and use of a measure of the value of the reserves discovered and a rate-of-return measure yielded no significant relationships between these variables and the level of expenditures.

Consequently, the development of a model of this type was determined to be infeasible at the present time.

F. Models of the Individual Firm

As a supplement to the industry models described above, a model of a "representative" firm was developed. The output of this model is not an estimate of industry reaction to policy changes, since no attempt is made to aggregate the reactions of "representative firms. The objectives of developing this model were (1) to develop a better understanding of the mechanism by which the aggregate reserve level changes, since it is the decisions of individual operators which cause any observed changes, and (2) to permit examination of the time pattern of reactions to policy changes.

The model is a simulation model in which the profitability of the firm is determined as a function of the exploration and development program which it follows over a period of 10 years. The firm is then assumed to choose that program which maximizes its profitability.

The outputs of this model cannot serve as quantitative estimates of the effects of tax policy changes on total reserve levels, but can only serve to support or refute the quantitative estimates generated by the industry model.

That is, if the industry model predict a 10% reserve decrease as a function of a certain policy change, the model of the firm would be expected to show a decrease of, perhaps, 2% to 25%. If the model of the firm indicated, say, no change or a 50% decrease as a result of the same policy change, this would tend to refute the results of the industry model.

The lack of quantitative significance of the firm model is due in part to the lack of data on which to base it. It consists of a detailed picture of the actions and decisions of an individual firm in exploring, developing, and producing crude oil. The firm takes its environment as fixed in making these decisions, and, in general, attempts to maximise its long-run profitability. The critical parameters in the model involve items such as the expected life of a well, the expected reserves found with a successful well, the success ratios for different types of wells, the costs of drilling, the costs of well operation, etc. Estimates of all these quantities are available based in industry aggregate data, but these industry averages mask considerable variability in individual values.

The concept of using a "representative" firm to analyze the effects of economic variables was developed by Marshall.* It would, in principle, be possible to extend this model to develop quantitative estimates of industry reactions, but such an extension is impossible with presently available data.

The model constructed for this study does have certain desirable general features, however. Among these are the manner of entering values of significant parameters and policy variables. The values of all these can be reset by the analyst at any time. This means that if better data becomes available in the future, the model can be immediately modified to utilize it. It also means that the model has potential for evaluating a number of other policy factors than the changes in depletion and intangible expensing that were the primary factors in the present study. For example, the effects of changes in changes in import policy, or allowable production days, or the combination of such changes with depletion changes, can be examined.

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*Marshall, Alfred, Principles of Economics, 8th edition, New York, The Macmillan Co., 1924.

VII. INDUSTRY RESERVE-REACTION FORECASTING MODEL

This chapter discusses a neoclassical approach to estimating the effects of certain tax policy changes on the levels of reserves held by the petroleum industry. The basic approach is to develop equations which incorporate those variables which should, according to economic theory, determine the level of reserves; to fit those equations to empirical data, and then to determine the effects of tax-policy changes on the independent variables.

The first portion of the chapter develops the theoretical structure by which reserve levels should be determined.

The latter part of the chapter discusses the problems of obtaining measurements of the variables in the model and the statistical calibration of the model.

A. Reserves Viewed as a Capital Stock

The basic approach of the study was to consider reserves as a capital stock necessary to support the production of liquid petroleum and natural gas. The optimal level of capital stock for a firm to hold is that level for which the marginal productivity of the stock is equal to the ratio:

$$\frac{\text{user cost of capital stock*}}{\text{price of output}}$$

The "user" cost of capital is the implicit rental price that the capital stock must earn to pay for itself and is, in general, a function of the price of the stock, the cost of capital funds to the firm, and any special tax treatment accorded to capital stock. The price of output is assumed to equal the after-tax marginal revenue at the specified level of capital stock, a condition which holds under competitive conditions.

If stocks are any higher than the level specified by this relationship, the output obtainable with the stock in excess of this level will not provide a revenue as large as the user cost of the additional capital, which means that cost of the excess capital will never be recovered.

If stocks are lower than the level specified by the relationship, then it would be profitable to add more capital, since the revenue from the output obtainable with the added capital will more than pay for the cost of the capital.

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*For a complete development, see, e.g., Jorgenson, Dale W., "Anticipations and Investment Behavior," in J.S. Duesenberry, G. Fromm, L.R. Klein, and E. Kuh, eds., The Brookings Quarterly Econometric Model of the United States, Chicago, Illinois, 1965, pp. 35-95.

It is clear that crude petroleum and natural gas reserves are a type of capital stock, and not simply an inventory, in that there is a definite technological relationship (represented by the MER) between the stocks held and the level of production. This limits the amount that can be produced from a given level of stocks, and requires a producer to maintain certain levels of stock to meet certain levels of production. Due to the MER, no more than a certain percentage of the total reserves can be produced during a year.

In order to utilize this marginal relationship, it is necessary to specify the production function which governs the relationship between capital stock and output, or at least determine the marginal productivity function for capital stock. If, for example, we were to assume a Cobb-Douglas type production function:

$$P = A K^{\beta} L^{a}$$

then the marginal productivity function would be,

$$\frac{\delta P}{\delta K} = \beta \frac{P}{K}$$

which then gives the optimum quantity of capital stock as

$$\hat{K} = \frac{SP}{C}$$

where $\hat{K}$ = optimum quantity of capital stock,

S = price of output,

C = user cost of capital stock,

P = quantity of output.

This relationship indicates that capital stock has a unit elasticity with respect to each of the independent variables. There are, of course, an infinite number of possible similar marginal productivity functions with other-than-unit elasticity.

1. Possible Production Functions

Considerable work has been published on using econometric models to evaluate the effects of tax changes on investment. Although there is certainly a lack of agreement as to the appropriateness of the many possible forms of production functions, much of the previous empirical work has been based on an assumption of constant elasticity of substitution (CES) production functions. It must be noted that a considerable portion of previous work* has dealt with attempts to determine the lag function appropriate to investment in capital goods, based on quarterly investment data. The approach taken here is somewhat different for two reasons. One is that the data for most of the variables of interest is available only on an annual basis. The other is that the primary objective of the study is an estimation of the long run effects of certain policy changes, and in view of the paucity of data available, it seems advisable not to attempt the estimation of an excessive number of

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*Jorgensen's, in particular.

parameters.

Lags have a number of different possible interpretations, and on the basis of these variations, there are a variety of ways to treat them. Jorgensen conceptualizes lags as arising from the physical aspects of investment in equipment. That is, the decision to invest is made on the basis of current values of the determining variables, but implementation of this decision occurs bit by bit over a number of quarters. This concept certainly appears appropriate in many phases of manufacturing, where the decision to invest may be followed by months of engineering, drawing, building construction, and machine installation. Such a concept of lags leads naturally to the conclusion that in empirical testing all independent variables have the same lag.

If the conceptual basis for the lag structure is taken not as the result of the physical time span of investment in capital goods, but rather as a resultant of reasonable patterns of expectation formation, then the variables need not exhibit the same lag structure.

The physical investment process which results in additions to proved reserves is the drilling of a well. Although this activity must be preceded by a chain of other activities, such as geological exploration and land acquisition, no change in proved reserves (or productive capacity) takes place until the well is essentially ready to produce. The elapsed time required to bring a well into production (once the decision to drill is made) is quite short -- as little as two months may be sufficient.

The annual drilling program of a large firm may consist of fifty wells or more and is typically decided on an annual basis. The program covers wells in a number of different areas and is subject to alteration during the year, based on the drilling results as the period progresses. Thus, the capital expenditure program for well drilling consists of a number of separate expenditures which do not have a technologically invariant relationship to each other, as do many capital expenditure programs in manufacturing industries. It would appear that the industry can make significant adjustments in its rate of adding new reserves within a year, and thus the concept of a rigid lag function when dealing with annual data seems perhaps unjustifiable.

Consequently, the model is based on the assumption that adjustments in reserves are largely accomplished within each year.*

With this assumption, it is possible to determine the relationship between the stock of reserves at the end of each period and the variables

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*Support for such an assumption is given by S. Almon's finding that capital investment in petroleum and coal showed the shortest lag of any SIC industry group, with over 95% of investment occurring within one year of authorization. S. Almon, "The Distributed Lag Between Capital Appropriations and Expenditures," Econometrica, 33, 1965, pp. 178-196.

which should determine the desired level of stock. The desired stock level represents, of course, a desired productive capacity, and this desired productive capacity should be a function of the expected levels of production, the expected cost of using the capital stock, and the expected revenue from selling the output produced with the capital stock.

The exact relationship to be expected depends on the form of the production function which applies to the industry, and on this there is comparatively little evidence. Due to lack of strong evidence to the contrary, a first-degree constant elasticity of substitution production function was assumed, where,

$$\hat{K} = \beta \left(\frac{S}{C}\right)^{\gamma} P* \tag{7.1}$$

With the optimal quantity defined, the problem becomes one of determining data values for the independent variables, S, C, P.

It should be noted that although the assumption of a CES production function is common in the literature, and is reasonable on its face, the implicit assumption of constant returns is not supported (nor made suspect) by any empirical evidence. Consequently, it seemed appropriate to calibrate a CES function of degree $V > 1$, which gives a desired stock level of

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*See, e.g., Eisner, R. and Nadiri, M.I., "On Investment Behavior and Neoclassical Theory," The Review of Economics and Statistics, 50, No. 3, pp. 369-382.

$$(7.2) \qquad \hat{K} = \beta \left(\frac{S}{C}\right)^{\gamma} P^{\delta}$$

where $\qquad \delta = \gamma + \frac{1 - \gamma}{V} < 1$ *

Because of the lack of information concerning the form of the function to be fitted, additional relationships were calibrated during the study, primarily in such linear forms as

$$(7.3) \qquad \hat{K} = a_1 + a_2 S + a_3 P + a_4 C$$

In the final evaluation of the appropriate forms to use for predicting the effects of tax policy changes, a number of factors were considered. These included theoretical considerations, the observed patterns of the residuals from the statistical calibrations, and the sensitivity of the results to errors in the data. Although a linear relationships is a close approximation for any relationship over a relatively small range, one of the objectives of the study was to predict the effects of changes which exceeded the range of the calibration data. The residuals for the calibration runs were examined for evidence of autocorrelation and other unusual patterns, and the multiplicative models showed no evidence of patterns, whereas many of the linear models did.

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*See, e.g., Eisner, P., "Tax Policy and Investment Behavior: Comment," American Economic Review (submitted).

Another possible advantage of the multiplicative models is that consistent percentage errors in the variables do not affect the estimates. As will be discussed in more detail in the subsequent section, the measurement problems involved in the study are likely to create percentage errors in the data.

2. The Single-Equation Model

The choice of a single-equation model over a multiple-equation model was based on the paucity of data available for model calibration and on evidence that, due largely to external restrictions on the industry and market, past values of the independent variables in the single-equation model had not been significantly interacting.

The historical data on reserves and production for the United States domestic industry are available from 1947 through 1966. Complete data on Canadian reserves and production are available from 1951 for liquids and from 1954 for natural gas. This means that a maximum of 20 data points are available for calibrating the models. If the models calibrated contain a large number of parameters to be estimated, the estimates of these parameters will, ipso facto, have large variances, thus increasing the uncertainty (or possible error) in projections based on them.

The other relevant consideration is whether the parameter estimates based on a multiple-equation model would differ greatly from those of a single-equation model. For the model here, the question is whether any of the independent variables in the capital stock equation are in fact dependent on other variables in the system. It might be proposed, for example, that the observed production values are functions of price, or that the current cost of new capital stock is a function of the existing quantity of capital stock. If this is true, then the single-equation model will produce biased estimates of the parameters. For example, if the observed production in t were actually a function of price, say $P_t = a_1 + a_2 S_t + e_t$, then P_t will be correlated with the error term in the equation determining reserves, and, as a result, the parameter estimates will be biased. On the other hand, the bias may be small (e.g., if, in fact, S_t has a very small effect on P_t) and the variances of the parameter estimates in the single-equation model will usually be lower than these determined by other methods.

The qualitative evidence on the variables in the single-equation model supports the usefulness of this approach. There is clear evidence that excess capacity existed during the entire period studied and that the observed production figures were the result of the demands of a fairly inelastic market. In fact, it has been suggested by some authors that observed crude petroleum production levels are the result of state prorationing controls based on forecasts of industry-wide demand.* If this is the case, then it appears that the industry would be willing to supply substantial additional production at the current price, so that price was not a determinant of the observed levels of production.

The production levels of natural gas also appear to be largely demand determined, and price (at least since 1954) has been regulated on a public utility basis and so was not demand determined during the period here examined.

As far as crude oil is concerned, price appears to be an "administered" price, one not determined by market demand.

The independent (single-equation) variable which might be affected by other independent variables is the user cost, which is a function of finding cost and which does vary inversely with total new reserves added. This variability, however, is due primarily to the variations in success rather than to a structural relationship. In other words, discoveries for a given total level of effort in a "good" year are high and, consequently, average finding cost is low, and the reverse is true in "bad" years.**

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*Lovejoy, Wallace F. and Homan, Paul T., Economic Aspects of Oil Conservation Regulation, Baltimore, Maryland, The John Hopkins Press, 1966.

**F. M. Fisher provides evidence regarding the factors which produce the year-to-year variations in finding cost.

it, the possible parameter bias it might cause.

B. Data Used for Calibration

The appropriate measurement of the quantities was one of the more difficult problems in the study. For any economic model such as this, the appropriate values of the explanatory variables are those representing the expectations of the individuals making the relevant decisions. Obtaining data on current expectations is fraught with problems, and obtaining historical data on expectations was essentially impossible. Consequently, the approach used here, as in all other studies of this nature, was to use some variable for which data was available and which might reasonably be assumed to reflect the expectations which existed at the time in the past when decisions which determined the values of the dependent variables were being made.

1. Reserves

For reserves, the official American Petroleum Institute and Canadian Petroleum Association estimates of proved reserves were used. Based on a specific and limited definition of reserves recoverable with present technology from existing wells, these figures have consistently been lower than actual recovery. These estimates do not reflect the reasonable expectations of the industry concerning the amount of oil that may ultimately be recovered from known fields but, more probably, represent a reasonably stable fraction of this. Although individual firms typically estimate their own reserves, there are no data available for these, and the proved reserve figures of the API and CPA are the only consistent estimates of reserves. These data are available on an annual basis, nominally the value of reserves as of December 31 of each year, in series beginning in 1947 for United States reserves and in 1951 for Canadian reserves.

There is a question here as to whether proved reserves are an appropriate measure of capital stock. It may be that the appropriate measure of capital stock is not the reserve level but, rather, the production capacity that this reverse level "supports." If so, then the dependent variable in the model should be a measure of capacity. The results of the analysis, however, would differ only if the relationship between productive capacity and reserves varies over the time span studied.

Whether such a variation exists is difficult to determine. The ratio between reported production capacity and reserves has risen steadily since 1948. On the other hand, state production restrictions ("allowables") have risen at a comparable rate, so that the effective production capacity has not risen relative to reserves. The question is, which concept is in the minds of the producers making decisions to drill for additional reserves? Since allowables are based on expected demand, and are well publicized, it seems doubtful that producers are contemplating that the productive capacity to be obtained from a drilling program will be in excess of that currently allowed by state restrictions. Unfortunately, the state restriction patterns are so complex and varied that it does not appear practical to construct a time series representing "effective" productive capacity. The data most closely reflecting effective productive capacity is production itself, since actual production has been at the maximum rate possible under the restrictions.

2. Price

For a price measurement, the average field price during the previous year was used. The average field prices of crude and natural gas were based on the published Bureau of Mines summaries. These prices were adjusted to constant 1965 dollars using the wholesale price index (excluding food and farm products). These constant dollar prices were then adjusted to reflect the tax adjustment based on the percentage depletion allowance. Table 7.1 presents the calculation of the series used.

Because of the unique nature of petroleum and natural gas reserves, the appropriate measure of price is particularly difficult to determine. Because the relationship between output and this particular type of capital stock (reserves) is not technologically fixed in the short run

TABLE 7.1

CALCULATION OF EFFECTIVE CRUDE PRICES

Year	Average Field Price	Price in 1965 Dollars	Price Plus Net Depletion Allowance Per Barrel
1950	2.51	3.10	3.439
1951	2.53	2.83	3.203
1952	2.53	2.90	3.292
1953	2.68	3.05	3.462
1954	2.78	3.15	3.576
1955	2.77	3.07	3.485
1956	2.79	2.96	3.360
1957	3.09	3.19	3.621
1958	3.01	3.10	3.519
1959	2.90	2.93	3.326
1960	2.88	2.91	3.303
1961	2.89	2.94	3.337
1962	2.90	2.95	3.349
1963	2.89	2.94	3.337
1964	2.88	2.92	3.300
1965	2.86	2.86	3.217

(in particular, production can be reduced rather quickly by shutting down wells), short-run reactions to price changes may be opposite in direction to longer-run reactions. For example, a price decline would be expected in the long run to lead to lower reserve stocks. In the short run, however it might result in a cutback in production which would increase reserve stocks above planned levels, since the planned depletion of reserves would not occur. The reverse could happen in the event of a price increase, if excess capacity existed.

The other problem with the price variable is that the marginal model is based on the assumption of competition, so that the price of output is the after-tax marginal revenue. In using price as the variable in the regression analysis, the implicit assumption is made that the after-tax marginal revenue is proportional to price during the period.

In calibrating the model, as was noted previously, a consistent percentage error in a variable will not affect the values of the parameter associated with this variable. On the other hand, in projecting changes in the independent variables caused by changes in tax policy, it is important to determine the correct percentage change in the variable as a result of the tax change. In this event, the distinction between marginal after-tax treatment revenue and price may be critical.

3. User Cost

Measurement of user cost presented the most difficult data problem in the study. User cost is the implicit rental price which must be earned by the capital stock in order to fully recover its true cost during its lifetime. Thus, it must take into account the interest charges on the investment in the asset, the true deterioration of the asset, and any special tax provisions which affect the net cost to the producer of a unit of capital stock. The formulation for user cost in this study is that presented by Coen:*

$$C = q\left[\frac{(r + \delta)(1 - u\,B)}{1 - u}\right] \qquad (7.4)$$

where B = the discounted value of depreciation charges stemming from a current dollar of capital expenditure,

δ = rate of true deterioration per year,

u = tax rate of business income,

r = interest rate,

q = the price of capital stock.

For the oil and gas industry, the formulation here must be extended, since a substantial portion of the finding cost is recoverable (for tax

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*Coen, Robert M., "Effects of Tax Policy on Investment in Manufacturing," American Economic Review, 58, No. 2, May, 1968, pp. 200-211.

purposes) immediately, through expensing rather than through depreciation, and another portion is recoverable only through cost depletion.

The estimates of the percentages of finding cost in each category (see Table 7.2) are based on the 1960 Depletion Survey and the 1959 and 1960 JAS surveys. Although there is no more recent comprehensive data available, the later JAS surveys show no evidence that the mix has changed appreciably.

TABLE 7.2

COMPONENTS OF FINDING COST

Depreciable Items	.121
Depletable Items	.223
Intangibles	.467
Dry Hole Costs	.189

The values for q were obtained from data on discovery-development cost for the period 1947-1963 presented in Petroleum Outlook, September, 1964. The history of corporate tax rates during the period studied were:

1946-49	38%
1950	42%
1951	50-3/4%
1952-63	52%
1964	56%
1965-67	48%

For r, the corporate Aaa bond rate was used. The true annual deterioration was estimated at 0.04, based on an average well life of twenty-five years. Since most of the expenses which make up finding cost can be taken as immediate tax deductions, and most of the remainder is recoverable only through depletion, the depreciable portion amounts to about 12.1% of the total, and changes in depreciation methods for tax purposes permitted only slight changes in finding cost.

The value of B used here is based on the present value of the four major components of finding cost. The dry hole and intangible drilling costs are recoverable immediately and consequently their actual value is also their present value. The present value of the depreciable items is based on Table 5.1. Three percent of the actual value of the depletable items is taken as present value, since that portion of these items recovered through cost depletion is typically recovered the year the expenses are incurred. The remainder is never recovered directly through cost depletion. *

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*A detailed discussion of the significance of this distinction is presented in Section VII.D. For example, the value of B for 1960 is computed as:

$$\begin{aligned} 0.121 \times 0.72677 &= 0.088 \text{ (depreciable)} \\ 0.656 \times 1.0 &= 0.656 \text{ (dry hole and intangible)} \\ 0.030 \times 1.0 &= \underline{0.030} \text{ (depletable)} \\ & 0.774 \end{aligned}$$

The series of finding cost shows considerable year-to-year fluctuation. The primary cause of the fluctuation is not changes in the factor costs of finding and developing oil and gas fields but, rather, is the year-to-year variation in the success rate and reserves per well. In a situation such as this, it would not seem reasonable for producers to base decisions on the scope of drilling programs on the observed recent costs of finding new reserves. It would seem reasonable instead for them to view high cost as the result of a "bad year," and actually expect their results during the next year to be better (i.e., their discovery-development costs per barrel to be lower). The reverse would apply to expectations after observation of a low-cost figure.

Consequently, first-order exponentially weighted moving averages were used to represent producers' expectations. Such averages reflect behavior that considers each observation to be composed of a permanent and a transitory component, where a deviation from the average value of the variable in the past is given some fractional weighting in computing the expected future value of that variable. The longer the averaging period, the lower the weight given to the most recent value of the data.*

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*See, e.g., Brown, Robert G., Statistical Forecasting for Inventory Control, McGraw-Hill, New York, 1959; Cox, D.R., "Predictions by Exponentially-Weighted Moving Averages and Related Methods," Journal of the Royal Statistical Society (Series B), 23, 1961, pp. 414-422; Winters, Peter R., "Forecasting Sales by Exponentially-Weighted Moving Averages," Management Science, 6, April, 1960, pp. 324-342.

These averages were then considered to be the expectations of q for each time period. To determine C, adjustments were made to reflect the changes in depreciation which occurred in 1954 and 1962. Since depreciable assets make up such a small part of this cost, adjustment is not large. The series was then adjusted by multiplying by the sum of the interest rate and the deterioration rate and dividing by one minus the tax rate to determine the user cost.

There are questions as to the accuracy with which this time series represents the user cost of capital. It is based on the reported proved reserves which, as noted previously, are very conservative estimates. If, however, the proved reserves represent a consistent fraction of the reserves estimated by producers, the C values presented here will be a constant multiple of the true C values. This would have no affect on the parameters estimated if the function to be fitted is of the forms shown in equations (7.1) and (7.2), or any form where the independent variables all appear in a multiplicative relationship.

The relevant changes in depreciation accounting occurred in 1954 and 1962 -- sum-of-the-years digits depreciation in 1954 and investment credit and guidelines depreciation in 1962. The effect of each of these was to produce a small reduction in user cost, and this adjustment has been made in the expectations variables, using Coen's* approach. The

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*Coen, Robert M., op. cit.

1954 change in depreciation was estimated on the basis of the comparison presented in Table 4.3, which amounts to an approximate 9% increase in the value of depreciation charges.

The computation of C_t is summarized in Table 7.3.

4. Production

Output data was based on API annual figures, which are adjusted estimates of the Bureau of Mines data, and on Canadian Petroleum Association data. Several data series were tested as representations of output expectations. The simplest form of expectation is the lagged value of output, but this value is not particularly reasonable in a situation where output shows a long-term secular trend, as is evident for both crude and natural gas. There was thus adopted the variable $P_{t-1} + \Delta P_{t-1}$, or the output observed the past year plus the change observed between two years previous and the past year. For a perfect linear trend, of course, this will provide a perfect prediction. In a uniformly fluctuating series, an expectation of $P_{t-1} - \Delta P_{t-1}$ will give a perfect prediction.

In calibrating simple linear equations of the form of equation (7.3), using $P_t + \Delta P_{t-1}$ as the expectation of output, it was clear that $P_t - \Delta P_{t-1}$ was a better fit to the data for crude oil, but not for natural gas. This indicated that the fluctuations in the time series were stronger

TABLE 7.3

FINDING COSTS AND USER COST OF CAPITAL

Year	Discovery-Development Cost per Barrel (Current Dollars)	Discovery-Development Cost per Barrel (1957-59 Dollars)	Expectation Based on Exponential Average (q)			Adjustment for Depreciation Tax Rate $\frac{(1-uB)/(1-k)}{1-u}$	$r_{t-1}+\delta$	C_t (Dollars per Barrel)		
			3 year	4 year	5 year			3 year	4 year	5 year
1947	.72	.956								
1948	.51	[illegible]								
1949	.65	.812								
1950	.72	.868	.8217							
1951	.60	.655	.8448	.8332		[illegible]	.0662	.068827	.067882	
1952	1.08	1.208	[illegible]	.7619	[illegible]	[illegible]	.0686	.064596	.065629	.068704
1953	.98	1.087	[illegible]	.9404	[illegible]	[illegible]	.0696	.085551	.082186	.081644
1954	1.45	1.603	1.0329	.9902	.9489	1.24483	.0720	.092577	.088749	.085048
1955	1.27	1.374	1.3179	[illegible]	1.1907	1.24483	.0690	.113198	.106559	.102273
1956	1.23	1.274	1.3454	1.2940	1.2516	1.24483	.0706	.118240	.113723	.109997
1957	1.78	1.794	1.3097	1.2860	1.2589	1.24483	.0736	.115103	.113020	.110638
1958	1.16	1.165	[illegible]	1.4892	[illegible]	1.24483	.0789	.152413	.146265	.141138
1959	.99	.977	1.3584	1.3595	1.3461	1.24483	.0779	.131727	.131833	.130534
1960	1.36	1.342	1.1677	1.2065	1.2229	1.24483	.0838	.121811	.125858	.127569
1961	1.20	1.190	[illegible]	1.2607	[illegible]	1.24483	.0841	.131365	.131983	.132150
1962	1.41	1.398	[illegible]	[illegible]	[illegible]	[illegible]	.0835	.126702	.127738	.128319
1963	1.14	1.132	[illegible]	1.2986	1.2911	[illegible]	.0833	.135477	.134278	.133502
1964	1.264	1.249	[illegible]	1.2320	1.2378	[illegible]	.0826	.123269	.124369	.124955
1965	1.018	.993	[illegible]	1.2388	1.2413	[illegible]	.0840	.124949	.125333	.125586
1966			1.1140	1.1405	1.1583	1.20444	.0849	.112707	.115388	.117189

than the underlying trend. As an approach to dealing with both these phenomena, it was assumed that the operators' expectations could be approximated by a second-order exponential moving average of the recorded production figures. Calibrations were run using two-, three-, four-, and five-year moving averages. The four- and five-year averages gave the best results for liquid reserves, as measured by R^2 and standard errors of parameter estimates, with four-year averages superior by a very small margin.

C. Calibration Results

The final calibrations were run on three basic models, all for liquid reserves and natural gas reserves, using combined United States and Canadian reserves and production, and using three-, four-, and five-year lags for production and finding cost in various combinations. The results are tabulated in Tables 7.4 and 7.5.

1. Liquid Reserves

There is no significant difference between the correlation coefficients or the price elasticities of reserves for the various time-lags when the output-elasticity is allowed to vary (equations 1, 2, 3, 4, 6, 7, 9, and 10 in Table 7.4). The R^2's range from 0.9005 to 0.9312, the price-elasticities from 0.020 to 0.173, and the output-elasticities from

TABLE 7.4

REGRESSION RESULTS FOR LIQUID RESERVES UNITED STATES AND CANADA

Dependent Variable	Constant Term	Production Lag	Production Elasticity	Relative Price Lag	Relative Price Elasticity	Degrees of Freedom	R^2	Durbin-Watson
(1) K_t	73.083	3 yr.	.883 (.113)	3 yr.	.020 (.063)	12	.9309	1.445
(2) $K_t+P_t-\overset{\Delta}{P}_t$	63.853	3 yr.	.891 (.120)	3 yr.	.028 (.067)	12	.9224	1.506
(3) K_t	68.847	4 yr.	.870 (.128)	4 yr.	.098 (.081)	12	.9312	1.182
(4) $K_t+P_t-\overset{\Delta}{P}_t$	57.366	4 yr.	.879 (.114)	4 yr.	.114 (.086)	12	.9205	1.244
(5) K_t	7.7673	4 yr.	1.0[a]	4 yr.	.171 (.036)	13	.6273	1.325
(6) K_t	156.10	5 yr.	.813 (.109)	5 yr.	.109 (.099)	11	.9136	1.136
(7) $K_t+P_t-\overset{\Delta}{P}_t$	133.29	5 yr.	.820 (.143)	5 yr.	.127 (.105)	11	.9005	.8547
(8) K_t	6.4405	5 yr.	1.0[a]	5 yr.	.229 (.048)	12	.6527	1.379
(9) K_t	77.37	5 yr.	.851 (.118)	4 yr.	.153 (.092)	11	.9232	1.296
(10) $K_t+P_t-\overset{\Delta}{P}_t$	64.464	5 yr.	.859 (.125)	4 yr.	.173 (.097)	11	.9124	1.382

[a]By assumption.

TABLE 7.5

REGRESSION RESULTS FOR NATURAL GAS RESERVES
UNITED STATES AND CANADA

Dependent Variable	Constant Term	Production		Relative Price		Degrees of Freedom	R^2	Durbin-Watson
		Lag	Elasticity	Lag	Elasticity			
(1) K_t	3.816	3 yr.	.663 (.032)	3 yr.	-.134 (.047)	11	.9810	1.0634
(2) $K_t+P_t-\hat{P}_t$	3.819	3 yr.	.662 (.033)	3 yr.	-.131 (.048)	11	.9801	1.7738
(3) K_t	4.190	4 yr.	.608 (.024)	4 yr.	-.107 (.041)	11	.9858	1.8620
(4) $K_t+P_t-\hat{P}_t$	4.208	4 yr.	.606 (.025)	4 yr.	-.101 (.042)	11	.9849	1.9152
(5) K_t	1.570	4 yr.	1.0[a]	4 yr.	-.421 (.173)	12	.3315	.395
(6) K_t	4.711	5 yr.	.533 (.020)	5 yr.	-.065 (.040)	11	.9861	1.8260
(7) $K_t+P_t-\hat{P}_t$	4.753	5 yr.	.526 (.021)	5 yr.	-.057 (.042)	11	.9846	1.8645
(8) K_t	1.570	5 yr.	1.0[a]	5 yr.	-.398 (.258)	12	.1657	.225
(9) K_t	4.69961	5 yr.	.534 (.021)	5 yr.	-.053 (.041)	11	.9851	1.8176
(10) $K_t+P_t-\hat{P}_t$	4.746	5 yr.	.527 (.022)	4 yr.	-.045 (.042)	11	.9836	1.8489

[a]By assumption.

0.820 to 0.891. For purposes of this study, the largest elasticity was chosen, so that the estimates of change derived would be on the high side. To add a further conservative bias, the elasticity value chosen for computation of reserve changes was set at one standard deviation above the computed parameter, a value of 0.270.

2. Natural Gas Reserves

The calibrations for natural gas reserves over the fourteen-year period from 1953 through 1966 gave somewhat anomalous results, showing a negative price-elasticity of reserves. The probable explanation of this result is that natural gas changed status during this period, going from a by-product of crude production to a product developed for its own value. The reserve level at the beginning of this period existed, not as a result of the economic decisions of producers, but rather because it had been created in the process of developing crude reserves. While the precise point at which "directionality"* became a significant factor in exploration is difficult to determine, it may be noted that the number of new gas fields found between 1947 and 1956 was about one-third the number of new oil fields found, but that, during the period 1957 to 1966, this proportion increased to one-half.

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*The exercise of a distinct choice as to whether to explore for oil or for gas.

As a consequence, the reserve figures do not represent desired reserve levels, and there is no way of factoring the gas reserves to obtain an independent estimate of desired reserve levels. The natural gas reserve-production ratio has declined steadily during this period, and prices and demand have advanced steadily. The indication is that actual reserves have not as yet reached the desired level (which may be as low as the twelve-to-one ratio observed for crude oil).

It is thus impossible at this time and in this way to determine a valid estimate for the relative price elasticity of natural gas reserves, and to predict the effect of a tax change.

D. Projection of Reserve Impact

In order to estimate the effects of changes in depletion and expensing provisions on oil reserves, it is necessary to predict the effects of such changes on the independent variables in the model.

1. Percentage Depletion

Percentage depletion is based on production and is unrelated to the cost of the exploration and development necessary to attain that production. Cost depletion, however, requires establishment, capitalization, and expensing of the costs of exploration and development.

As percentage depletion is reduced, the amount of cost depletion taken will rise. Elimination of percentage depletion will force all producers to claim cost depletion. The change to cost depletion will result in a change in the tax deduction created from a given expenditure on exploration and development.

At present, a number of exploration and development costs, such as lease-acquisition and geophysical costs, may be recovered (for tax purposes) only by capitalization and depletion over the life of the asset. Most of these expenses are effectively non-recoverable under present tax laws. Under percentage depletion, the allowed deduction is the same whether these expenses are incurred or not (as it is based on a fixed percentage of depletion). If these expenditures were recovered through cost depletion, the allowable deduction would be a function of the funds actually expended on exploration and development. Thus, the reduction of percentage depletion and the concomitant switch to cost depletion would reduce the direct after-tax cost of exploration and development and, hence, of finding new reserves.

Based on the 1959-1960 JAS surveys, 22.3% of exploration and development costs are those items which are capitalized and recovered through some form of depletion.* The portion of exploration and development expenditure currently being claimed as cost depletion is

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*Based on the total of 1959 and 1960 costs, or $\frac{874 + 1007}{8452} = 0.22255$.

estimated as 3.0%.*

As percentage depletion is reduced, the fraction of exploration and development which is actually claimed and recovered as cost depletion would rise until all the expenses in this classification would be claimed as cost depletion. The point at which essentially all depletion is claimed as cost depletion would be that point at which the allowable deductions for cost and percentage depletion are equal. Based on an estimate that percentage depletion at the current rate allows 85.6% excess depletion over true cost depletion,** this "break-even point" would occur when percentage depletion was 14.4% of the current rate or 4% (= 0.144 x 27.5%).

Assuming a fairly uniform distribution of properties, the fraction of these depletion expenses on new properties claimed as cost depletion would vary in linear fashion from the current level to 100% as allowable percent depletion varied from the current 27-1/2% to 4%.

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*Based on 1960 tax returns, taking the cost depletion claimed by mining and manufacturing firms (which should represent most of the cost depletion based on exploration and development, as contrasted with cost depletion based on acquisition costs of producing properties). This cost depletion of $122 million represents 3.0% of total exploration and development costs of $4127 million (JAS survey data).

**See Table 5.4.

This, then, gives the percentage of finding cost which is capitalized and recovered through cost depletion (PDCDD) as,

$$PFCDD = 25.6 - 0.82\ (PCDEP),$$

for percent depletion (PCDEP) between 27-1/2% and 4%.

$$PFCDD = 22.3, \text{ for } PCDEP < 4\%$$

With percent depletion below 4%, essentially all expenditures would be recovered through cost depletion.

Another side of this change is that the number of properties on which percentage depletion is claimed will drop as the allowable percentage is reduced. This means that the average percentage depletion claimed will diverge more and more from the allowable rate. To estimate this, it is assumed that the fraction (percentage depletion claimed/ percentage depletion allowable) will vary from its present level to zero as the percentage depletion rate varies from 27-1/2% to 4%. Using the 1960 depletion survey data, the present fraction is 0.8986.* Under these assumptions, the effective percent depletion (EFDEP) is given by

$$EFDEP = -4.2 + 1.05\ (PCDEP), \quad 4 \leq PCDEP \leq 27\text{-}1/2$$

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*Based on depletion claimed by mining and manufacturing, Table 5.2, $\frac{1590 + 528}{1752 + 605}$. Although these figures include claims on both foreign and domestic properties, cross checks based on percentage depletion actually claimed versus 27-1/2% of gross income for foreign and domestic properties indicate that the effective percentage depletion does not differ appreciably between foreign and domestic operations. See Table 5.6.

$EFDEP = 0 \quad PCDEP < 4$

The effective price per barrel (PRICE) as a function of field price and tax policy is

$$PRICE = FPRIC\ (1.0 + EFDEP \times \text{Tax Rate})$$

That is, the effective price is the field price plus the tax subsidy.

As noted above, the after-tax finding cost will be reduced by a reduction in percentage depletion, since the fraction of finding cost which is actually taken as a deduction against income will increase. The appropriate treatment of expenses which must be capitalized and recovered through depletion is identical to that of those which are capitalized and recovered through depreciation.

To determine the total effect of a depletion change, then, the effect of the change on the effective price and the user cost must be computed, and these revised values then substituted into the equation for determining the desired reserve level. For the multiplicative forms of the equation, the ratio of desired reserves under the existing tax structure to those under a revised structure can be computed directly as a function of the changed variables only, since all other variables will cancel if they remained unchanged.

The tax benefit generated by a change to cost depletion is a time stream of tax savings over the life of the well. For uniform rate of physical depletion, the present value of this time stream may be computed by assuming an interest rate and then discounting each of the future flows to its present value. For example, at a discount rate of 4%, the present value of a $1.00 expenditure to be recovered through cost depletion deductions would be $.70. Similarly, at a discount rate of 10%, the same expenditure would be equivalent to a current deduction of $.46; and, at 20%, the value would be $.31.*

The net effect on after-tax finding cost must be determined by computing a revised value of B in equation (7.4).**

Table 7.6 summarizes a calculation of the projected results of elimination of percentage depletion using 1966 data as a base.

2. Expensing of Intangibles

The tax provisions that permit the expensing of intangible drilling costs provide a benefit by allowing deduction against current income of certain expenses which, for most taxpayers, must be deducted over the

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*These values were computed on the basis of a thirty-year well life with output each year equal to 8% of remaining reserves.

**As an example, the 1960 value, assuming a 10% discount rate and elimination of percentage depletion would be

$$\begin{aligned}
0.121 \times 0.72677 &= 0.088 \text{ (depreciable)}\\
0.189 \times 1.0 &= 0.189 \text{ (dry holes)}\\
0.467 \times 1.0 &= 0.467 \text{ (intangibles)}\\
0.223 \times 0.46 &= \underline{0.103} \text{ (depletable)}\\
& 0.847
\end{aligned}$$

This gives a total tax adjustment factor of 1.13759, compared to the actual value of 1.20444, or a decrease of 5.6%.

TABLE 7.6

CALCULATION OF EFFECTS OF A TAX CHANGE

1966 Effective Price	=	2.93 (1.0 + 0.2471 · 0.48)
	=	3.2775
New Effective Price		
Assuming No Percentage Depletion	=	2.93
1966 Tax Adjustment Factor	=	1.20444
Revised Tax Adjustment Factor	=	1.13759
1966 User Cost (4 year exponential average)	=	0.115388
New User Cost	=	0.108984
1966 Relative Price	=	28.404
Revised Relative Price	=	26.885
$\dfrac{\text{New Reserve Level}}{\text{Present Desired Level}}$	=	$\left(\dfrac{26.885}{28.404}\right)^{.270}$
	=	0.985

useful life of the asset. The result of this tax treatment is to lower the effective finding cost, and the result of eliminating this treatment would be to increase the effective finding (and user) cost.

The amount of the effective increase must be estimated by determining the present value of the expense deduction under alternative tax policies, since the difference is not in the total deduction allowed, as with percentage depletion, but is only in the timing of the deduction. Under the assumptions (1) of a 10% discount rate, (2) that the items presently expensed would be capitalized and recovered over a 25-year period through depreciation charges and (3) that the tax change would not apply to the cost of dry holes, the present value of $1.00 of intangible expense would be $.539. Since these intangibles are approximately 46.7% of finding cost, this change would increase the effective after-tax finding cost by decreasing the present value of the tax deductions (the value of B in equation 7.4).* This, in turn, would result in an increase in user cost. Using 1966 as a base, the value of B is 0.553, compared

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*For example, the value of B for 1960 under a policy of not expensing intangibles would be

$$\begin{aligned}
0.121 \times 0.72677 &= 0.088 \text{ (depreciable)}\\
0.189 \times 1.0 &= 0.189 \text{ (dry holes)}\\
0.467 \times 0.539 &= 0.252 \text{ (intangible)}\\
0.030 \times 1.0 &= \underline{0.030} \text{ (depletable)}\\
& 0.559
\end{aligned}$$

to 0.768 under current tax laws. The total adjustment for depreciation and tax rate is then 1.40131, an increase of 16% over the present value.

To determine the effect on reserves, the revised user cost is computed and the ratio of new desired reserve level to existing desired reserve level is computed, in the same manner as was illustrated for depletion changes.

The evaluation of the effects of the various possible combinations of changes is summarized in the following chapter.

VIII. RESULTS OF RESERVE REACTION FORECASTING MODEL

This chapter summarizes the predicted impacts on reserves of various possible changes in the percentage depletion allowance and in the option to expense intangibles.

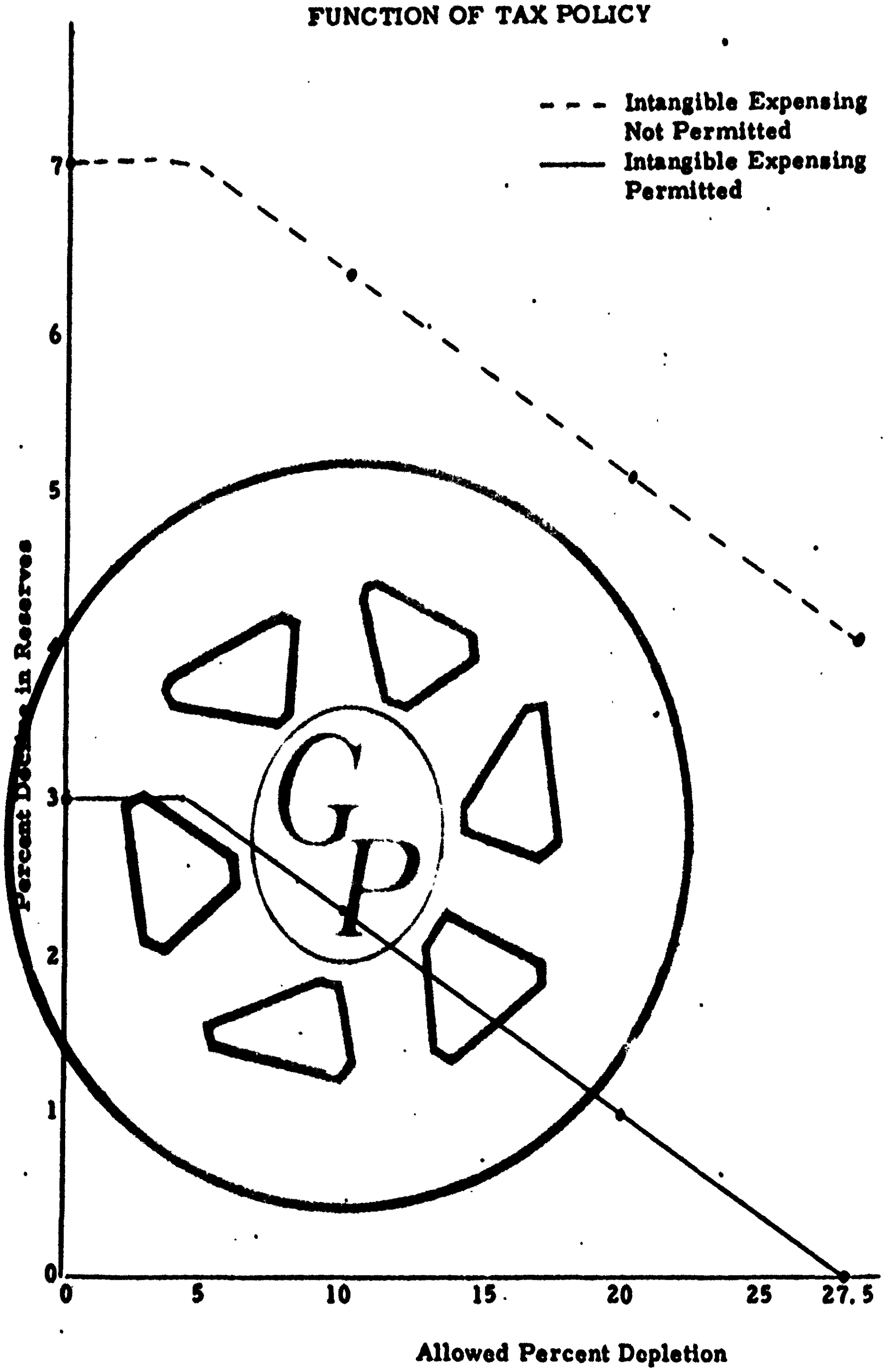
The impacts have intentionally been estimated at maximum levels, so that probable impacts would, in actual cases, be less than those presented here.

A. Impact of Tax Policy Changes on Liquid Reserves

The percentage declines in liquid reserves which would result from reductions in percentage depletion were calculated for various levels of that depletion between 25% and zero. The results are presented in Figure 8.1. The computations were made by the methodology presented in Section VII.D, utilizing a relative price elasticity of 0.270. In making these computations, and in keeping with the objective of deriving a pessimistically biased estimate, it was assumed that posted prices do not represent marginal after-tax revenue, i.e., that production is below the equilibrium level. This means that the marginal production has a cost less than its selling price, so that part of the marginal revenue is subject to tax.

FIGURE 8.1

PREDICTED RESERVE DECLINES AS A FUNCTION OF TAX POLICY



To estimate marginal revenue, the operating costs of marginal wells from Adelman* were subtracted from the constant dollar price. Since there is available no time series for lifting costs, Adelman's estimate, which represents the period around 1960, was used. Again, the use of such a figure will cause an upward bias, if any, in the impact estimates, since the higher the lifting cost, the closer are price and marginal revenue to equality, and since current lifting costs would be, if anything, higher than the figure used.

At a constant dollar price of \$2.93 and a lifting cost of \$.68, the marginal after-tax revenue is

$$\underset{\text{Price less income tax}}{\$2.93 - (\$2.93 - \$.68)\,.48} + \underset{\text{plus depletion subsidy}}{\$.3775} = \$2.1975$$

The marginal after-tax revenue subsequent to elimination of depletion would then be \$1.85.

Carrying through the remaining calculations in the manner illustrated in Section VII.D, the estimated percentage declines in liquid reserves as a function of percentage depletion rates and intangible expensing are summarized in Figure 8.1.

The result of elimination of percentage depletion would be a 3.1% reserve decline. The result of eliminating intangible expensing would

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*Adelman, M. A., "Oil Production Costs in Four Areas," Proceedings, Council of Economics, AIME, 1966.

be a 4.0% decline in reserve levels, and the result of both would be a 7.1% decline.*

B. Impact of Tax Policy Changes on Natural Gas Reserves

Due to the problems discussed in Section VII.C, no estimate was made of the impact of tax policy changes on natural gas reserves. It should be noted that the natural gas situation differs from the crude situation in a number of ways. As a major difference, the rate-setting procedures for natural gas would likely result in the passing-on of the tax increase from any change in depletion rates to consumers as a price increase.

This would then imply no change in the relative price variable to the firm and no effect on reserves. The net effect would be the elimination of the subsidization of natural gas consumers by all taxpayers, which is a reasonable enough change.

In any event, it seems doubtful that the true sensitivity of natural gas reserves to the tax changes investigated in this study would be appreciably higher than the sensitivity of liquid reserves.

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*These results were obtained by calculating the effects of each change and each combination of changes separately. The apparent additivity of results is accidental, and results from rounding to the nearest 0.1%.

C. Implications of the Results

Perhaps the most interesting result of the analysis is the comparatively larger effect on reserve levels of the option to expense intangibles. This is reasonable in that the expensing of intangibles directly reduces the costs of exploration and development, while the percentage depletion allowance provides benefits only to actual production. Extension of this expensing privilege to all exploration and development costs might, in fact, more than offset the decline in exploration and development (and, hence, reserve levels) that would result from elimination of percentage depletion. As tax revenues gained through elimination of percentage depletion would exceed those lost through extending the expensing option, the net result might be increased total revenues with unchanged (or even increased) reserve levels.

This trade-off can be estimated only roughly; but, based on the 1959-1960 figures, elimination of percentage depletion would increase tax revenues (in the long run) by $1200 million per year, while expensing of all other items would create a one-time tax loss of $720 million.*

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*The estimated tax revenue increase is 48% of the estimated annual excess depletion (85% of $2500 million). The one-time loss is created by expensing of $1500 million of annual exploration and development that are currently capitalized and recovered through depreciation and depletion, based on an estimate that only 5% of this is currently charged during the year of actual expenditure.

The size of the effect of elimination of intangible expensing depends critically on what alternative tax treatment will be available for recovery of this investment, and on what discount rate should be applied to future flows of funds. The computations in this study were based on the assumption that the available alternative would be recovery over a twenty-five year period through depreciation on a sum-of-the years digits method, and on a discount rate of 10%.

A discount rate lower than 10% would decrease the effect of the tax change, while a larger discount rate would increase it. Since the funds being discounted are future tax benefits and thus are not "risky" flows, the 10% rate used is, if anything, high.

If recovery were permitted over, say a ten-year period, rather than twenty-five years, the impact of the change would be sharply lowered. The discounted present value of a dollar recovered through ten year sum-of-the-years digits depreciation is \$.792, compared to the \$.539 for recovery of the same dollar over a twenty-five year period. If this were the relevant tax alternative to intangible expensing, the estimated decline in reserves based on 1966 data would be 1.9% rather than 4.0%.*

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*This gives a B value of 0.671, and a total tax adjustment factor of 1.293262, compared to a tax adjustment factor of 1.401315 for twenty-five year recovery.

These predicted impacts are based on the assumption that any loss of tax benefits would be borne entirely by producers. As noted earlier, this is unlikely to happen in the case of natural gas. It is also unlikely to happen in the case of liquid hydrocarbons. To the extent that the loss in tax benefits is shifted, either forward (as is likely to happen with natural gas) or backward to landowners, the profitability of production will remain unchanged and there will be little effect on reserves.

If, for political reasons, the price of crude is held constant, the problem of shifting becomes one of reducing costs. It is believed that this is possible, at least in the long run. Even as wells have gone deeper, the average drilling cost per foot has remained constant, so that foot for foot cost has declined. So long as the industry is profit-satisfying, costs are not reduced as much as possible; but, if it becomes necessary, the potential for further economies apparently is there.

Perhaps more importantly there is the question of royalty payments to landowners. A firm which is repeating the full cash flow from percentage depletion receives $13.75 per $100 production, and is paying between 12-1/2% and 15% of its income as royalties.* Since land is an absolutely fixed supply, its price is in principle determined by competition

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*Some firms operating abroad pay up to approximately 70% in royalties. The standard domestic royalty is 1/8 although many are higher.

among buyers, so that is buyers bid less, the price would have to fall. Of course, if depletion were removed in a single step, it would not be possible to reduce royalties simultaneously, since leases are agreed to for long periods of time; but over a period of 10 years or so, it should be possible to shift taxes at least in part to owners.

If the depletion allowance were to be removed in a single step, the impact on profits would be considerable, for it is generally considered that tax shifting is very difficult in the short run.

The impact on exploration might not be nearly as large, however, since as was shown in Section VI. E, the rate of exploration in the past has shown little relationship to profits.

The efficiency of percentage depletion in encouraging exploration is questionable as well. The results of the investigation of the incidence of depletion may be summarized thus:

Approximately 15%	accrues to lease owners as royalties,
Approximately 4%	accrues to other non-operating interests,
Approximately 23%	accrues to foreign activities,
Approximately 60%	of domestic depletion accrues to the 35 largest firms.

The evidence points to a tendency of all these percentages to increase over time. Hence, if the subsidy being paid to the industry has as its purpose the maintenance of domestic reserves through encouragement of the small independent explorer/operator, it seems a highly inefficient means of support. The amount which actually accrues to the small explorer directly must be less than one-fifth of the total, and is likely to be considerably less than that; percentage depletion, it must be emphasized, applies only to production, and the small explorer has no production during the critical period when he must finance his drilling. He has not the benefit of property aggregation to spread his deductions and avoid the net income limitation, and, as has been shown, he reaches this limitation and loses his cash flow from depletion very quickly.

If the small operator benefits from depletion, it is by the courtesy of the larger firms which finance him, either directly or by bottom-hole or dry-hole contributions or the practice of "farm-outs." Evidently, the larger firms are sharing these benefits less and less over time, however, since larger firms account for an increasing share of expenditures on domestic exploration and development, and yet, at the same time, produce more abroad.

In view of these facts, it seems unlikely that the presence or absence of the depletion allowance would have a significant effect on exploration. The apparent decline in domestic exploration activity is almost entirely in the smaller companies, while the leveling off of exploration expenditures among the larger companies is as likely to be attributable to the leveling off of demand, the excess capacity in the industry, and the greater attraction of foreign operations, as it might be to the changes in profits. All the measures which the study has examined suggest that the industry has a very weak response to profit changes, above a certain minimum level. (That is, as long as sufficient reserves are found <u>and</u> profits remain above a minimum level, there exists a weak response to changes in the profit level.) The decline of the smaller companies as they fall below this minimum level reflects the increasing dependence on technological changes to offset the costs of drilling deeper. It may also reflect the increasing difficulty of finding reserves by exploration. Since it is the smaller companies whose profit rate is low enough to be sensitive to year-to-year changes, a change in the depletion provisions would probably affect these small companies. However, their income from depletion appears to be very low compared with their exploratory outlays, and a subsidy which aids small explorers in so erratic a fashion appears to be unlikely to reverse the trend to concentration of exploratory expenditures in the industry.

The removal of percentage depletion is likely to have another side effect, one of which the impact is difficult to measure. There is reason to suspect that the elimination of percentage depletion as an option may lead to a decline in posted wellhead prices, since the integrated major producers would no longer benefit from high posted prices. This, then, would probably lead to the demise of many smaller producers, either through merger or through being bought out by the large, integrated firms.

There is another method of tax avoidance which would certainly occur to some extent if percentage depletion were eliminated, but which is not related to intangible expensing. This would be the inter-firm sale of proved properties so that the discovery profit would be taxed at capital-gains rates instead of as ordinary income. This behavior would reduce the impact of depletion reductions unless the gains from such sales were taxed as ordinary income.

In conclusion, it may be estimated that elimination of percentage depletion and elimination of the option to expense intangibles might result in a reserve decline of as much as 7%. Since the analysis was based on combined United States-Canada data, the implied reserve decline would be split between the United States and Canada. The relative decline in each country would depend on whether the tax changes implemented in Canada were the same as those implemented in the United States. If Canada made no changes, then there could be a shift of exploratory activity to Canada by firms capable of operating in either country, unless the United States tax laws governing profits of foreign subsidiaries were modified to eliminate any tax benefit from Canadian production, or

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the import restrictions were modified to make the United States a totally closed market.

IX. A SIMULATION MODEL OF THE FIRM

This chapter presents a detailed simulation model of a single producer-refiner of crude. The purpose of this model is to provide supporting information for the industry models and also to provide information as to the time pattern of reactions to policy changes.

The initial portion of the chapter provides a flow chart and description of the operation of the model. The latter part is a description of how the model is used to determine reactions to policy changes.

A. Model Description

The purpose of the model was to simulate the operation of a crude producer and refiner under alternative tax policies regarding the rate of percentage depletion and the option to expense intangible drilling costs. The model simulates three basic decisions of the operator -- (1) the exploration program, (2) the development program, and (3) the amount of crude produced. The overall program compares the long-run profitability of the firm under each of a group of alternative ten-year exploration and development programs, and selects from among them the one with the greatest profitability.

To determine the effects of tax policy changes, the program must first be run with the tax policies currently in effect, and then rerun with the revised tax policies in effect. The predicted effect of the policy change is then determined by comparing the reserve changes during the ten-year simulation period (for the producer's most profitable program) under current tax policies to the reserve changes (also for the producer's most profitable program) under revised tax policies.

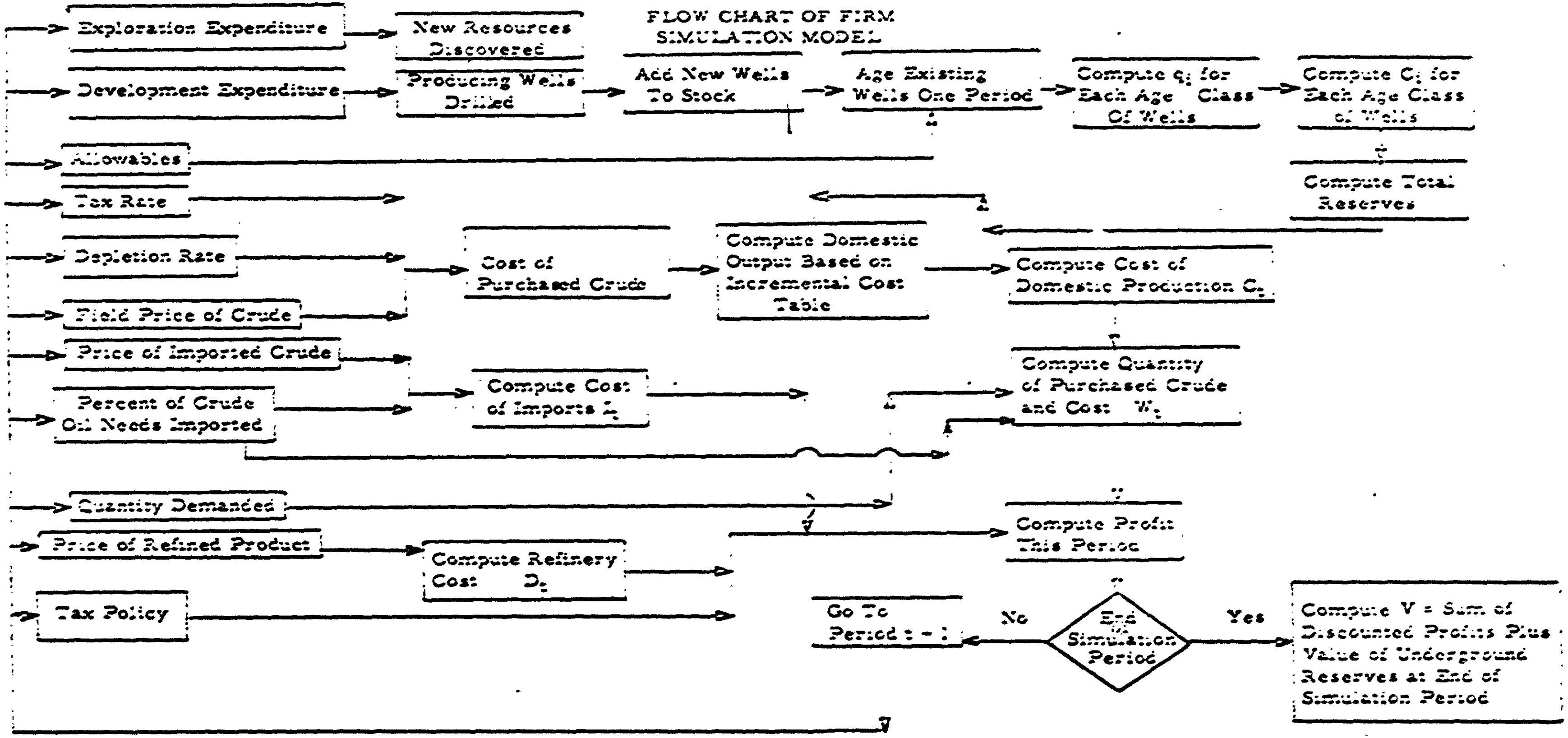
B. Model Operation

Figure 9.1 is a flow chart of the model operation. The program is initiated by specifying a ten-year program of exploration and development expenditures. The program then determines, in sequence, for the first simulation year:

1. The number of exploratory wells drilled,
2. The number of these which are successful,
3. The new reserves discovered,
4. The number of development wells drilled,
5. The number of these which are successful,
6. The available output from each group of existing wells,
7. The cost of operation for each group of wells,
8. The reserves for each group of wells and the total reserves,
9. The production from existing wells, based on equating the marginal production cost per barrel to the cost of purchasing crude,
10. The amount and cost of purchased imported and domestic crude,
11. The refinery operating cost,
12. The net profit.

At this point, the simulation for the first year is complete and the same computations are done for the second simulation year, the third year, etc., through the tenth year.

FIGURE 9.1
FLOW CHART OF FIRM SIMULATION MODEL



The interrelationships on which calculations of these quantities are based are taken primarily from available empirical information on the petroleum industry. Comparatively few data are available on the detailed operations of individual firms, making it necessary to use aggregate industry data for such things as average well production, drilling costs, etc. The use of such aggregate data obscures differences in the operations of individual firms.

Before operation of the simulation program, it is necessary to run an "intialization" program, which creates a "typical" situation for the firm in terms of its stock of producing wells, development fields, etc. Only a single initialization run is required. The inputs required for the program are defined by the input data sheets presented in Appendix D. Appendix E is the output of a sample run of the program and Appendix F is a complete program listing.

C. The Structure of the Model

The inputs to the model consist of all the items on the left side of Figure 9.1. They include:

1. A set of dollar values of exploration expenditure and development expenditure for each year of a ten-year period,
2. A state allowables value specified as a number of days,
3. The corporate tax rate,
4. The percentage depletion rate,
5. The average posted price of domestic crude,

6. The price of imported crude,
7. The quota on crude imports,
8. The final demand for refined products from the firm,
9. The average price of refined products,
10. A set of tax policies specifying the tax treatment of each class of exploration and development expenditures.

1. Exploration and Development Expenditures

The program takes the value specified for exploration and development expenditure and computes the number of exploratory wells as,

(9.1) $$N_e = 0.00000590 \times E$$

and the number of development wells as

(9.2) $$N_h = 0.00001639 \times H$$

where N_e = number of exploratory wells

N_h = number of development wells,

E = exploration expenditure in dollars,

H = development expenditure in dollars.

These values are based upon the reported industry results for 1959-1963 (See equations 8 and 11, Appendix C.).

The numbers of successful wells of each type are obtained by multiplying these values by the historical success ratios,

0.1797 for exploratory wells, and

0.7517 for development wells.

(The source data are presented in Tables A.30 and A.31.)

The quantity of reserves found by the program is based on the number of successful exploratory wells, utilizing 2,500,000 barrels/well as a basis. This is about 90% greater than the actual average proved reserves per exploratory well for the period 1958 through 1966, and is based on estimates that eventual total recovery from a field will be on the order of twice the proved reserves figure. It is necessary to use this "ultimate" reserve figure since the firm in the simulation (contrary to actual circumstances) cannot revise its reserve estimates during the course of production from a field. The data used for estimation are in Tables A.30 and A.32. Development activity does not generate new reserves in the simulation, even though new reserves are attributed to development activity in published statistics. In reality, development activity adds to proved reserves not by finding new reserves but by proving the extent of those already found through exploration activity.

2. Output and Production Cost

All new wells brought in during a year go into one "age class" of wells and remain together until they are shut down. Thus, all wells in a given age class have the same production and decline curves. The daily output of each well in an age class is given by,

$$(9.3) \qquad q_t = \begin{cases} q_o & \text{if } t < t^* \\ q_o\, e^{-a_8 (t - t^*)} & \text{if } t \geq t^* \end{cases}$$

where q_o = the flush production rate,

t = total elapsed production days,

t^* = the flush production period,

a_8 = decline rate.

The length of the flush production period, t^*, and the decline rate, a_8, are determined by the ratio of development expenditures to a moving average of exploration expenditures. The exponential smoothing function is used to approximate the lag between exploration work and development. Under this approach, the development wells brought in during a simulation year are located in fields discovered in prior years. The following lag equation is used,

$$(9.4) \qquad \hat{E}_t = .6\, E_t + .4\, \hat{E}_{t-1}$$

where E_t = exploration expenditure in year t,

$\hat{E}_t$ = moving average for year t.

The duration of flush production and the decline rate for a given well class are affected by current development expenditures and exploration expenditures over the previous years. The initial ratio is defined as the observed ratio in the period from 1955 through 1965, 1.08573. (The source data are shown in Table A.33.) Maintenance of this ratio produces a flush period of 180 days and a decline rate of 0.000440 (per day). These functions are shown in Figures 9.2 and 9.3. The functions shown in the figures were tested in trial runs to insure that the well production characteristics approximated the reserves. A larger ratio than 1.08573 means overdevelopment and will reduce the flush production period and increase the decline rate. This increases the output per field in the early years but decreases output per field in later years.

The production possible during a simulation year is calculated by integrating equation (9.3). The production can be limited by restricting the number of days to some specified figure for wells producing more than a stated number of barrels per day. Table A.34 shows the days allowable by the Texas Railroad Commission for the period 1958 to 1962. Thus, for certain wells, the production is not as much as would be indicated by the well characteristics. This factor has the effect of deferring income from an investment in crude oil production. Since future income is discounted, production restrictions, ceteris paribus, reduce the expected profit of the firm from crude oil production.

The actual total production is the output of all wells for which the cost of producing is less than the cost of purchased crude. Older wells being more expensive to operate on a per-barrel basis, the effect of a price decrease is to make wells in older age classes uneconomical.

FIGURE 9.2
LENGTH OF FLUSH PRODUCTION
CRUDE OIL PRODUCTION FUNCTION

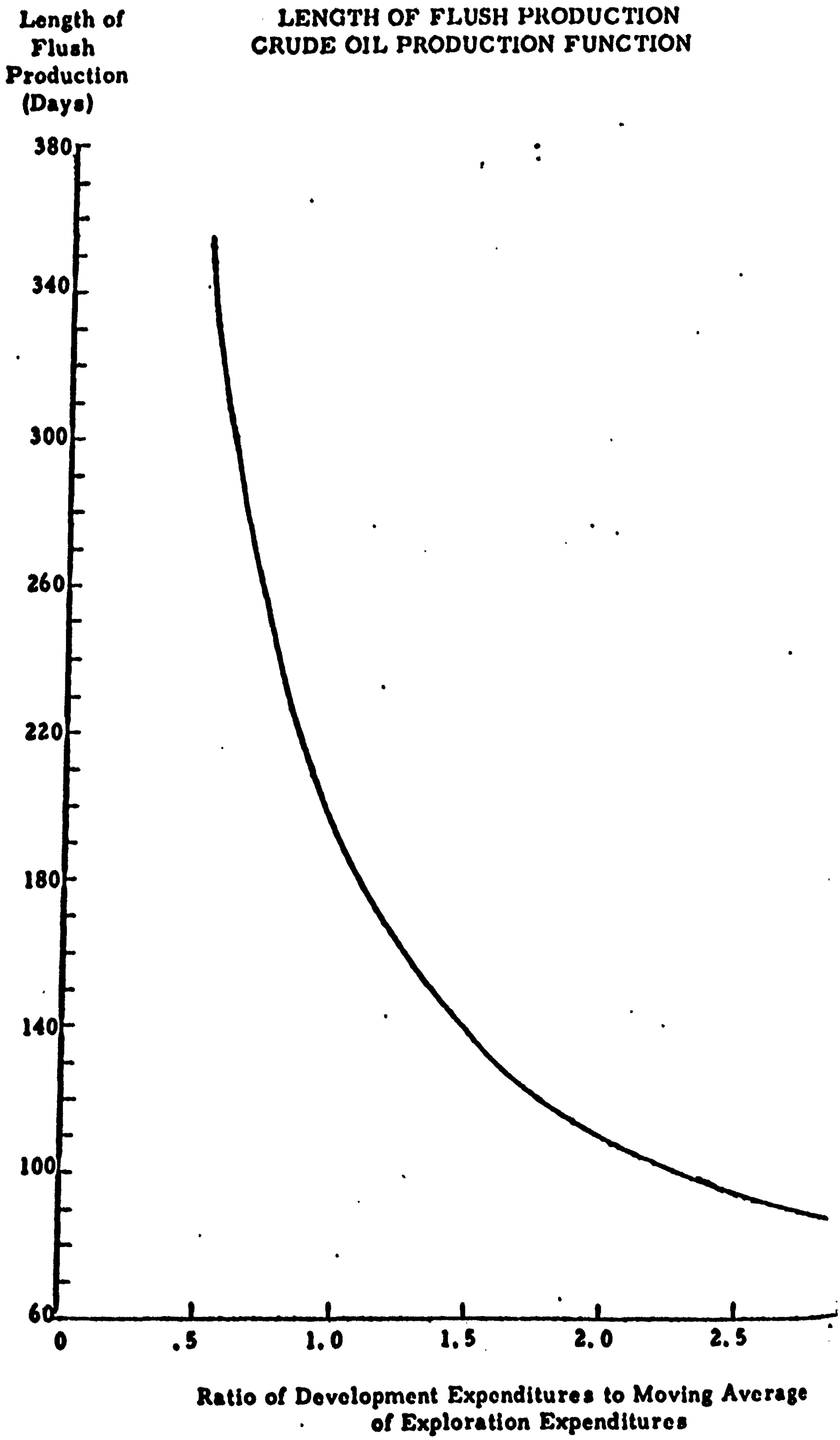
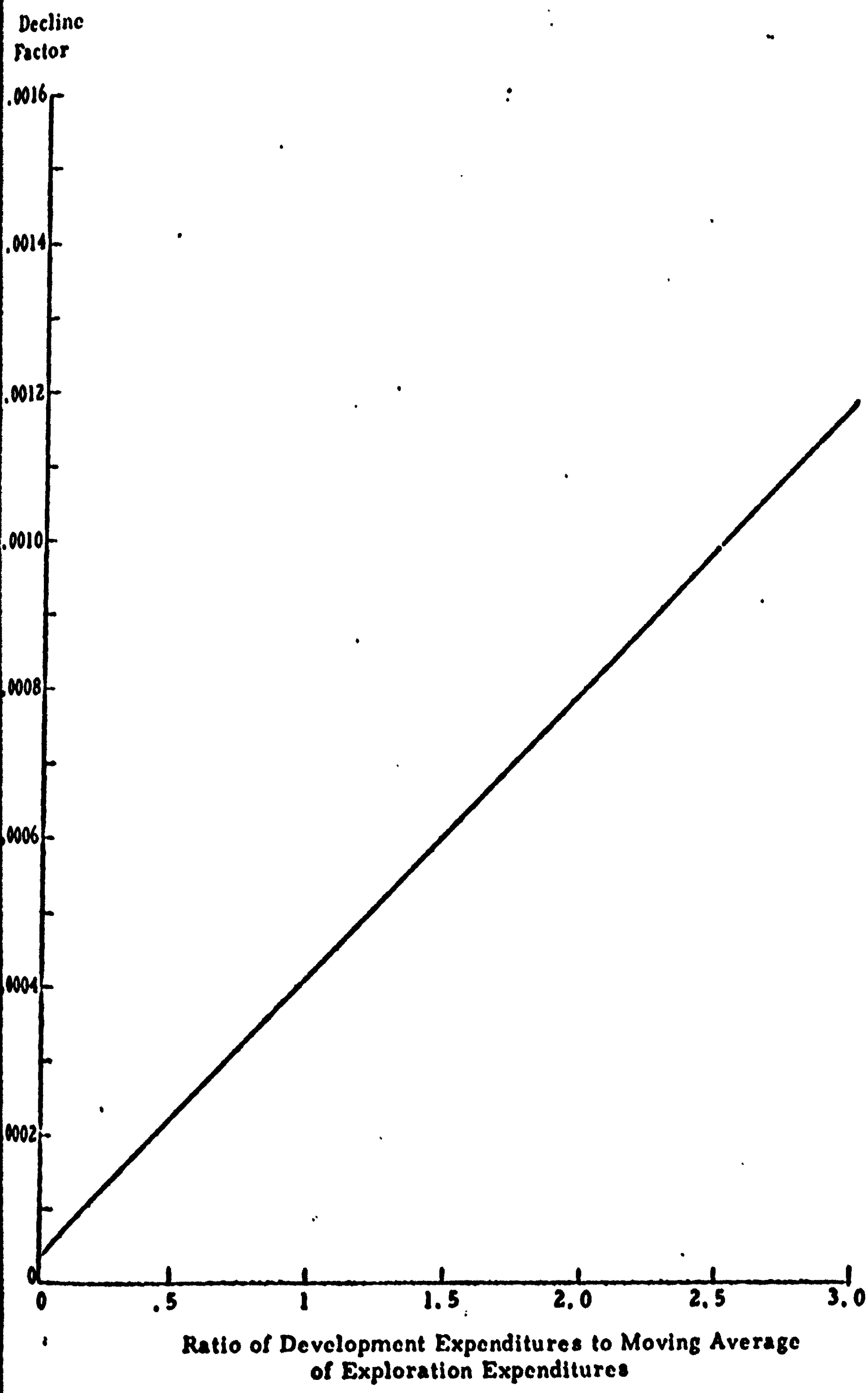


FIGURE 9.3
DECLINE FACTOR
CRUDE OIL PRODUCTION FUNCTION



This cost equality will be discussed in more detail below.

It is assumed that the expected economic productive life of a well is thirty (30) years and flush production is 75 barrels per day. The exponent parameter, a_8, is fit by balancing the following two equations:

$$(9.5) \qquad q_e = q_o e^{-a_8 (t - t^*)}$$

$$(9.6) \qquad R = \sum_{i=1}^{n} \left[q_o t^* + \int_{t^*}^{t_u} q_o e^{-a_8 (t - t^*)} \, dt \right]$$

where q_o = 75 barrels (assumed)

q_e = 0.206 barrels (determined below)

t = 10950 days (assumed)

t^* = 180 days (assumed)

n = $\hat{N}_e + \hat{N}_h$ number of wells

R = 2,500,000 N_e/N

It should be noted that a_8 will vary for each well class depending on the ratio of development to exploration expenditures (see Figure 9.3). Therefore, it was necessary to use equation (9.6) to check if production capacity equaled new reserves. The model parameters are the result of balancing the two equations.

The operating costs for wells are based on the data in A Theory of Crude Oil Prices by Robert L. Karg.* The Karg estimates are

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*Karg, Robert L., A Theory of Crude Oil Prices: A Study of Vertical Integration and Percentage Depletion Allowance, unpublished thesis, University of Pittsburgh, Pittsburgh, Pa., 1962, p. 141.

averages for 1953. These estimates are adjusted to 1963 by the whole-sale price for industrial commodities.* The price indexes for 1953 and 1963 are 90.1 and 100.7, respectively. The adjustment factor is 100.7/ 90.1 = 1.118.

Using the Karg data and the above adjustment factor, the operating cost function for crude oil production is

$$C_r = 0.380\,(1.118) + 0.702\,(1.118) \cdot q$$

or $$C_r = 0.435 + 0.785\,q$$

where q is the production per day.

The incremental cost for the j^{th} well class is:

$$I_q = (0.435 + 0.785 \cdot q) \,/\, q_j\,(1 - r) - \text{tax subsidy}^{**}$$

where q is production per day for well class j and r is royalty interest.

The incremental cost for purchased crude is:

$$I_r = p$$

The tax subsidy is

pPR

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*Economic Report of the President, United States Government Printing Office, Washington, D.C., 1968, p. 264.

**As discussed earlier, percentage depletion acts as a subsidy since the producer receives a tax deduction for each barrel produced, without regard to cost of production or exploration.

where $\quad p$ is price,

P is percentage depletion allowance, and

R is tax rate.

Using the following estimates

$$p = 2.90$$

$$P = 0.275$$

$$R = 0.52, \text{ and}$$

$$r = 0.125 \qquad \text{(1/8 of production)}$$

A well will be economical as long as

$$I_r \geq I_q \text{ or}$$

$$2.90\,(1 + 0.275 \cdot 0.52) \cdot \geq (0.435 + 0.785\,q)/\left[q\,(1 - 0.125)\right]$$

$$3.3147 = (0.435 + 0.785\,q)\,/\,q\,(0.875)$$

$$2.900 = 0.435/q + 0.785$$

$$q_e = \frac{0.435}{2.115} = 0.206 \text{ barrels/day}$$

where $\quad q_e$ = minimum economic production level.

The total crude production costs are obtained by summing the production costs for all the individual wells that are operated at the current prices and costs. Crude production is restricted to refinery demand.

Refinery operating costs are computed by fitting a linear cost function to the data presented in Tables A.35, A.36, and A.37. The resulting equation is:

(9.7) Daily Refinery Cost = 26,639.96 + 0.363 x barrels produced.

The representative firm is assumed to operate three such refineries so that the total refinery operating cost is given by

(9.8) Refinery Costs/Day = 79,904.88 + 1.089 x barrels produced.

The firm is assumed to import the maximum quantity of crude permitted, and the purchases of domestic crude are taken as the remainder after subtracting production and imports from the crude required by the refineries.

3. Revenues and Profits

Revenue is based on sales of refined products, computed on the basis of an average price of refined products (See Tables A.38, A.39, and A.40.). Since the prices quoted at the refinery are higher than actually contracted, $4.32 per barrel is used.

The gross profit per period is then computed as the revenue from refined products less the total of all costs or

(9.9) $$\text{Profit} = D_t - R_t - C_t - W_t - E_t - H_t - I_t$$

where D_t is revenue from refined products,

R_t is the operating costs of refineries,

C_t is crude oil production costs,

E_t is the cost of exploration,

H_t is the cost of development,

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W_t is the cost of purchased crude,

I_t is the cost of imported crude.

The income tax payable each period is computed based on the costs incurred and the specified tax treatment of these costs.

The various categories of expenditures in exploration and development follow the outline in Table 9.1. The simulation is designed so that the tax treatment of each category is read in during each simulation year. Thus, a category can be changed from one tax treatment to another in the simulation.

The fraction of the exploration and development costs which are in each of the eight categories are based on the historical data from Petroleum Facts and Figures and the JAS Surveys.

The net profit (cash flow basis) after taxes is then computed and stored in memory. This point marks the completion of one year of the total simulation period; and, at this point, the entire sequence repeats for another year. After going through this sequence for the appropriate number of years, the stored net profit figures are discounted to the beginning of the simulation period and the value of underground reserves is computed. These figures represent, then, the discounted value of the specific exploration and development program undertaken during the simulation period, given the tax and import policies and the field prices which existed during that period.

TABLE 9.1

TAX TREATMENT OF COSTS IN PETROLEUM INDUSTRY FOR SPECIFIED CATEGORIES

CATEGORY	DESCRIPTION	TREATMENT
Exploration		
1	Dry Hole Drilling Costs	Expensed
2	Other Exploration Costs for Dry Holes (Includes Lease Acquisition and Geophysics Costs)	Expensed
3	Intangible Drilling Costs for Producers	Expensed
4	Tangible Drilling Costs for Producers	Capitalized and Depreciated
5	Other Exploration Costs for Producers (Includes Lease Acquisition and Geophysics Costs)	Capitalized and Recovered Through Percentage Depletion
Development		
6	Dry Hole Drilling Costs	Expensed
7	Intangible Drilling Costs for Producers	Expensed
8	Tangible Drilling Costs for Producers	Capitalized and Depreciated

4. Value of Reserves at End of Simulation

The profit during the simulation period is not the sole measure of the value of a particular exploration and development program. At the end of the period, the firm has a stock of underground reserves the size of which is a function of the program followed. The discounted value of these reserves must be determined as a second measure of the value of a particular program.

Increasing crude oil reserves should have a depressing effect on the value of these reserves. Therefore, the value of reserves is altered by decreasing the number of production-days allowable for evaluating reserves if the refiner-producer has increased reserves during the simulation. The following equation is used:

$$AD = \begin{cases} AD & \text{if } (R_o - R_t) \geq 0 \\ AD\,(R_o/R_t) & \text{if } (R_o - R_t) < 0 \end{cases} \tag{9.10}$$

where AD = days allowable,

R_t = reserves at end of simulation,

R_o = reserves at beginning of simulation.

The valuation of reserves at the end of the simulation is based on the economic break-even point for keeping a well in production. The following equations are used if there are no production restrictions. The formulation for well class j is:

$$(9.11) \qquad q_e = q_o \, e^{-a_{g,j} (t_u - t_j^*)}$$

where q_e = economic break-even point in last year of simulation,

$a_{g,j}$ = decline factor for well class j,

t_u = end of economic productive life for well class j,

t_j^* = end of flush production for well class j.

Solving for t_u for well class j

$$t_u = (\ln (q_o/q_e) / a_{g,j}) + t_j^*$$

The revenue function for well class j is

$$\int_{T_j}^{t_u} p \cdot (1-r) f(q_j) \, dt$$

where p = price of domestic crude oil in the last period of the simulation,

r = royalty interest,

$f(q_j)$ = production function for well class j,

T_j = production days of well class j which includes last period of simulation.

The cost function includes operating costs and depletion allowance but not any depreciation charges. The cost function is,

$$\int_{T_j}^{t_u} \left[a_1 + a_2 f(q_j)\right] dt$$

The depletion allowance is:

$$\int_{T_j}^{t_u} p \cdot P \cdot (1-r) f(q_j)\, dt$$

where P = percentage depletion allowance,

$f(q_j)$ = production function for well class j.

The continuous discount factor for evaluating reserves for the end of the simulation is:

$$\int_{T_j}^{t_u} e^{-i(t - T_j)}\, dt$$

where i = discount rate.

Using the corporation income tax rate for the last simulation year and combining the last four equations, the value of reserves for well class j discounted to the end of the simulation is:

$$V_j = \int_{T_j}^{t_u} \Big\{ \left[p \cdot (1-r) f(q_j) - (a_1 + a_2 f(q_j))\right] (1-R) + p \cdot P \cdot (1-r) f(q_j) R \Big\} \cdot e^{-i(t - T_j)}\, dt \qquad (9.12)$$

where R is the tax rate.

Multiplying terms within $\{ \}$, equation (9.12) becomes,

$$V_j = \int_{T_j}^{t_u} \{ p\,(1-r)\,f\,(q_j)\,(1-R) - a_1\,(1-R) - a_2\,f\,(q_j)\,(1-R) + p \cdot P \cdot (1-r)\,f\,(q_j)\,R \}\, e^{-i\,(t - T_j)}\, dt$$

Collecting the terms into those containing $f\,(q_j)$ and those not containing $f\,(q_j)$,

$$V_j = \int_{T_j}^{t_u} \{ - a_1\,(1-R) + [\,p\,(1-r)\,(1-R) - a_2\,(1-R) + p \cdot P \cdot (1-r)\,R\,]\, f\,(q_j) \}\, e^{-i\,(t - T_j)}\, dt \tag{9.13}$$

The following substitutions are made:

$$b_1 = - a_1\,(1-R)$$

and

$$b_2 = p\,(1-r)\,(1-R) - a_2\,(1-R) + p \cdot P \cdot (1-r)\,R$$

It should be noted that these terms have no j subscript and therefore are the same for all j. Making these substitutions, equation (9.13) becomes,

$$V_j = \int_{T_j}^{t_u} \{ b_1 + b_2\,f\,(q_j) \}\, e^{-i\,(t - T_j)}\, dt \tag{9.14}$$

or

$$V_j = \int_{T_j}^{t_u} b_1\, e^{-i\,(t - T_j)}\, dt + \int_{T_j}^{t_u} b_2\, f\,(q_j)\, e^{-i\,(t - T_j)}\, dt$$

The integral for the production function is separated into two parts. The function is

$$f(q_j) = \begin{cases} q_o & \text{if } t \le t_j^* \\ q_o \, e^{-a_{8,j}(t - t_j^*)} & \text{if } t > t_j^* \end{cases}$$

The calculations of V_j can be separated into three cases. The cases are:

Case 1. $T_j < t_j^* < t_u$

$$V_j = \int_{T_j}^{t_u} b_1 \, e^{-i(t - T_j)} \, dt + \int_{T_j}^{t_j^*} b_2 \, q_o \, e^{-i(t - T_j)} \, dt$$

$$+ \int_{t_j^*}^{t_u} b_2 \, q_o \, e^{-a_{8,j}(t - t_j^*)} \, e^{-i(t - T_j)} \, dt$$

Case 2. $t_j^* \le T_j < t_u$

$$V_j = \int_{T_j}^{t_u} b_1 \, e^{-i(t - T_j)} \, dt + \int_{T_j}^{t_u} b_2 \, q_o \, e^{-a_{8,j}(t - t_j^*)} \, e^{-i(t - T_j)} \, dt$$

Case 3. $T_j \ge t_u$

$$V_j = 0$$

The formula used for calculating the first term in cases 1 and 2 is:

$$b_3 = \int_{T_j}^{t_u} b_1 \, e^{-i\,(t - T_j)} \, dt = \frac{b_1}{i} \left(1 - e^{i\,(T_j - t_u)}\right)$$

The second term in case 1 is:

$$b_4 = \int_{T_j}^{t_j^*} b_2 \cdot q_o \, e^{-i\,(t - T_j)} \, dt = \frac{b_2 \cdot q_o}{i} \left(1 - e^{i\,(T_j - t_j^*)}\right)$$

The third term in case 1 is:

$$b_5 = \int_{t_j^*}^{t_u} b_2 \cdot q_o \, e^{-a_{8,j}\,(t - t_j^*)} \, e^{-i\,(t - T_j)} \, dt$$

$$= \frac{b_2 \cdot q_o}{a_{8,j} + i} \, e^{i\,T_j + a_{8,j}\,t_j^*} \left[e^{-(a_{8,j} + i)\,t_j^*} - e^{-(a_{8,j} + i)\,t_u} \right]$$

The calculation of V_j in case 1 is:

$$V_j = b_3 + b_4 + b_5$$

The second term in case 2 is calculated in the following way:

$$b_6 = \int_{T_j}^{t_u} b_2 \cdot q_o \, e^{-a_{8,j}\,(t - t_j^*)} \, e^{-i\,(t - T_j)} \, dt$$

$$= \frac{b_2 \cdot q_o}{a_{8,j} + i} \, e^{i\,T_j + a_{8,j}\,t_j^*} \left[e^{-(a_{8,j} + i)\,T_j} - e^{-(a_{8,j} + i)\,t_u} \right]$$

The calculation for V_j in case 2 is:

The above is done for each well class and summed. The discounted reserve is then:

$$V = (\sum_j V_j) / (1 + i)^m$$

where V = discounted value of reserves to the beginning of the simulation,

V_j = value of reserves at the end of simulation discounted back to the end of simulation for well class j,

i = discount rate,

m = number of simulated years.

The following equations are used if there are production restrictions. Substituting q_m, minimum production to which production restrictions apply in equation (9.11),

$$t_m = (\ln (q_o/q_m) / a_{g,j}) + t_j^*$$

where t_m = end of production restriction, and

q_m = production level above which production restrictions apply.

The profit function is the same as above except that the continuous discount factor cannot be used since the well is not operated every day. Therefore, the annual discount factor is used. The calculations are done year by year. The algorithm uses the following definitions for iterating over time:

$$\left.\begin{aligned} t_b &= T_j \\ t_e &= T_j + AD \end{aligned}\right\} \quad \text{year 1}$$

$$\left.\begin{aligned} t_b &= t_e \\ t_e &= t_b + AD \end{aligned}\right\} \quad \text{year 2}$$

$$\left.\begin{aligned} t_b &= t_e \\ t_e &= t_b + AD \end{aligned}\right\} \quad \text{year k}$$

The general equation for year k is:

$$V_k = \left[\int_{t_b}^{t_e} \left\{ b_1 + b_2 f(q_j) \right\} dt \right] (1 + i)^{-k} \tag{9.16}$$

This equation is basically the same as (9.14) except that the annual discount factor is used instead of the continuous discount factor. There are four cases.

Case 1. $t_b < t_e \leq t^*$

$$V_k = \left[\int_{t_b}^{t_e} b_1 \, dt + \int_{t_b}^{t_e} b_2 \, q_o \, dt \right] (1 + i)^{-k}$$

Case 2. $t_b < t^* < t_e$

$$V_k = \left[\int_{t_b}^{t_e} b_1\, dt + \int_{t_b}^{t^*} b_2\, q_o\, dt + \int_{t^*}^{t_e} b_2\, q_o\, e^{-\alpha_{8,j}(t-t^*)} dt \right] (1+i)^{-k}$$

Case 3. $t^* < t_b \leq t_m$

$$V_k = \left[\int_{t_b}^{t_e} b_1\, dt + \int_{t_b}^{t_e} b_2\, q_o\, e^{-\alpha_{8,j}(t-t^*)} dt \right] (1+i)^{-k}$$

Case 4. $t_b > t_m$

$$V_k = \int_{t_b}^{t_u} b_1\, e^{-r(t - T_j)} dt + \int_{t_b}^{t_u} b_2\, q_o\, e^{-\alpha_{8,j}(t-t^*)}\, e^{-r(t-T_j)}$$

where $r = i/365$

This last case uses the continuous discount factor since production is not restricted. The formulae used for calculating the above cases are:

Case 1. $V_k = \left[b_1 (t_e - t_b) + b_2 \cdot q_o (t_e - t_b) \right] (1+i)^{-k}$

Case 2. $V_k = \Big[b_1 (t_e - t_b) + b_2 \cdot q_o (t^* - t_b)$
$\qquad - (b_2\, q_o/\alpha_{8,j}) (e^{-\alpha_{8,j}(t_e - t^*)} - 1) \Big] (1+i)^{-k}$

Case 3. $V_k = \Big[b_1 (t_e - t_b) - (b_2\, q_o/\alpha_{8,j}) \Big(e^{-\alpha_{8,j}(t_e - t^*)}$
$\qquad - e^{-\alpha_{8,j}(t_b - t^*)} \Big) \Big] (1+i)^{-k}$

Case 4. $$V_k = -(b_1/r)\left(e^{-r(t_e - T_j)} - e^{-r(t_b - T_j)}\right) - \left(b_2 q_o e^{a_{8,j} t^* + rT_j} / (a_{8,j} + r)\right)\left(e^{-(a_{8,j} + r)t_u} - e^{-(a_{8,j} + r)t_b}\right)$$

V_k is summed over all years, then summed over all well classes j.

The firm at the end of the simulation has deferred tax credits in the form of capital expenditures for exploration and development which have not been fully depreciated. The last step in evaluating reserves is to add these tax credits to the value of reserves as calculated above. As in the simulation, the sum-of-the-digits method is used for calculating depreciation. The following formula is used:

$$D = \left\{ \sum_{t=M-(N-1)}^{M} \sum_{k=j}^{1} \left\{ (E_t' + H_t') \cdot k \cdot 2/N(N+1) \right\} (1+i)^{k-(j+1)} \right\} R$$

where

D	=	tax credit,
$E_t' + H_t'$	=	expenditures in period t which have been capitalized,
k	=	the year,
N	=	the number of years for depreciation,
R	=	tax rate,
j	=	number of years left for depreciating capitalized expenditures in period t,
M	=	number of years simulated, and
i	=	discount rate.

The last term, $1 + i$, is the discount factor. Finally, the discounted tax credit is added to the reserve value.

D. The Evaluation of Alternative Programs

In using the simulation to determine refiner-producers' reactions to policy changes, the approach is to repeat the simulation with current policies, utilizing a number of alternative exploration and development programs. The discounted values of profits and underground reserves for the different programs are then compared, and the producer is assumed to follow the program which maximized his profitability. The procedure is then repeated, under a different set of tax policies. The effect of the policy change is reflected in the producer's choice of a different exploration and development program when the changed policy is in effect.

X. RESULTS OF SIMULATIONS OF THE FIRM

A. Inputs for Simulation

The simulation was run eight times (representing two different firms under four possible tax policies) with nine different expenditure patterns. The initial conditions were the same in all cases. One firm was assumed to be able to produce 100% of its domestic crude oil needs from its own wells; the other 60% of its domestic crude oil needs from its own wells. The tax treatment for the first simulations of capital expenditures (TO1 and TO5) is the same as current law and the percentage depletion rate is 27.5. The production restriction is 120 days for wells producing more than 50 barrels per day. The other parameters are the same as those discussed in Chapter IX. The initial conditions are shown in Appendix F, reports 1 and 2. (Each printout has a report number in the upper right side of the page.)

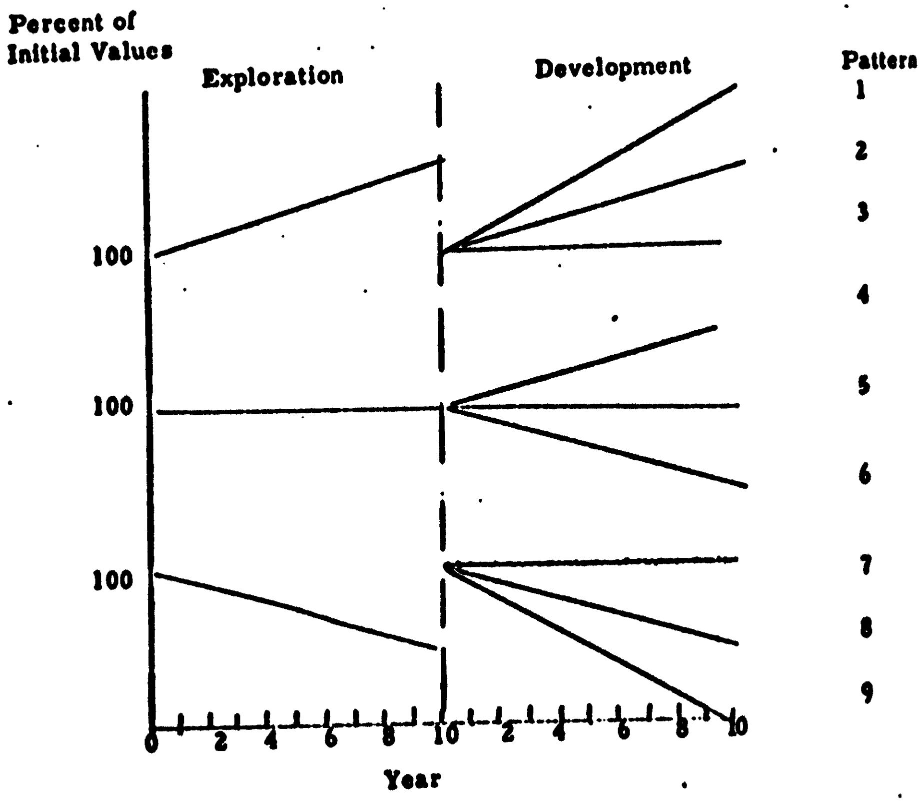
The capital expenditures were separated into nine patterns. The expenditure patterns are shown in Figure 10.1. The following equations were used for the patterns:

Pattern (Run Number)	Exploration	Development
1	$E_n = E_o(1.02)^n$	$H_n = H_o(1.04)^n$
2	$E_n = E_o(1.02)^n$	$H_n = H_o(1.02)^n$
3	$E_n = E_o(1.02)^n$	$H_n = H_o$

34-472 O - 69 - 16

FIGURE 10.1

PATTERNS OF CAPITAL EXPENDITURES



Pattern (Run Number)	Exploration	Development
4	$E_n = E_o$	$H_n = H_o(1.02)^n$
5	$E_n = E_o$	$H_n = H_o$
6	$E_n = E_o$	$H_n = H_o(.98)^n$
7	$E_n = E_o(.98)^n$	$H_n = H_o$
8	$E_n = E_o(.98)^n$	$H_n = H_o(.98)^n$
9	$E_n = E_o(.98)^n$	$H_n = H_o(.96)^n$

where E_o is initial exploration expenditures,

H_o is initial development expenditures, and

n is the simulation year.

The initial capital expenditure values are shown in Appendix E, report 4.

The nine patterns were run for four different tax treatments. The four cases are:

1. No change in the tax treatment,
2. No percentage depletion,
3. All costs for successful wells are depreciated and dry holes are expensed,
4. No percentage depletion, and all costs for successful wells are depreciated and dry holes are expensed.

The above four cases were then repeated for each firm.

The input parameter for royalty interest has been set at 0.125, i.e., 1/8 of physical production goes to the owner of the land. The program operates so that the refiner-crude producing company must purchase this crude oil at the domestic crude oil price.

B. Analysis of Results

The results from the simulations for the model of the firm are summarized in Tables 10.1 to 10.9. The various simulations are identified by the first line of each report. The identification is:

Code: Firms Supplying 100% of its Crude	Code: Firms Supplying 60% of its Crude	Tax Treatment
TO1	TO5	No changes in present taxes
TO2	TO6	Depletion allowance is removed
TO3	TO7	Dry holes are expensed and successful wells are depreciated
TO4	TO8	Depletion allowance is removed and dry holes are expensed and successful wells are depreciated

The run number on the left in Tables 10.2 to 10.9 identify the expenditure patterns shown in Figure 10.1. The summary of the discounted value of profits and reserves are shown in Table 10.1.

The interpretation of these results indicate that given present conditions, the firm is encouraged to increase development expenditures relative to exploration expenditures. The changes in the policy, i.e., changes in depletion allowance and in tax treatment of capital expenditures, would likely cause a decrease in development expenditures relative to exploration expenditures. For the case where the firm supplies 100% of its domestic crude oil requirements from its own wells, i.e., cases TO1, TO2, TO3, and TO4, the simulation results indicate no changes in exploration expenditures. If the firm is limited to a total less than or equal to 100% of its refinery demand in the beginning of the simulation, then the results indicate that there will be very little change in reserves for different tax policies if other economic factors do not change. In the other case, where the firm starts at 60%, the "best" position implies that the firm increases exploration expenditures and also increases development expenditures under present tax treatments. However, Expenditure Pattern 4 is not significantly different from Expenditure Pattern 1 for the 60% firm, i.e., the profitability of not increasing exploration is only slightly less than that of increasing exploration. Therefore, the economic pressure under present tax treatments is to increase development expenditures relative to exploration expenditures and the profitability of increasing exploration expenditures is slight.

The differences in the results shown in Tables 10.2 to 10.9 between various tax treatments indicates the interrelationship of the Federal regulations. The following comparisons are of interest:

TO1 with TO3
TO2 with TO4
TO5 with TO7
TO6 with TO8

In each comparison, the significant difference is that, in the latter, the cost of successful wells are depreciated. The firm for each comparison has a greater discounted value for profits and reserves when successful wells are depreciated. The reason for this result is that the decrease in discounted profits is less than the discounted tax credit which is included in evaluation of reserves. This indicates that by changing the depreciation regulations, tax payments could be increased while actual worth of the firm is increased if the assumed discount rate and the distribution of drilling costs as shown in Appendix E report 1 are reasonable. It should be noted that "other exploration" costs are the same for successful as unsuccessful exploratory wells. Since these parameters plus the success ratio are set in the initialization phase, it would be necessary to make separate runs for testing variation in these parameters. This example shows how various input parameters can be analyzed by using the simulation model.

The above interpretations of the figures in Table 10. 1 have been made in the context of the parameters shown in Appendix E, report 1. None of these parameters were changed for any of the runs shown in Table 10. 1. Three basic economic factors (refining demand, prices and royalty interest) were held constant. Also, in the case of the 100%

firm, the firm was not allowed to increase its share of the market. In the "real world," one would expect these <u>ceteris</u> <u>paribus</u> conditions to be altered by the effect on profits of increased taxes for the refining-producing company. If one were to assume either an inelastic demand for refinery output or an inelastic supply of oil property, then it would be expected that the refining-producing firm would exert pressure in either or both markets to offset his loss in profits. Thus, although the results of the simulation show that there will be a slight decrease in reserves for the 100% firm by changing the tax laws, the results do not imply that there would not be significant changes in prices.

The average production from a well decreases as the productive age of the well increases. This factor has been expressed in the simulation model as an exponential decay function. The decline parameter is shown in Figure 9.3. The initial conditions for the simulation runs give an annual decline of about 15% and an economic production life of approximately 30 years. However, by the introduction of production restrictions as shown in Appendix E, report 2, the effective decline rate is approximately 8% instead of 15%. If there were no production restrictions, the firm would hold approximately six years of reserves for the steady state (Expenditure Pattern 5). However, the production restriction used for the simulations have caused reserves to be about

12 times annual production. The production restrictions cause the discounted value of the reserves and thus the value of the reserves to be less than if there were no restrictions. The production restrictions were, however, held constant for the simulations shown in Table 10.1 and no evaluation of the effect of production restrictions on the discounted value of profits and reserves was made.

To summarize the results of the simulation, present tax regulations are causing development expenditures to increase relative to exploration expenditures. For the 100% firm, the investigated changes in depletion and depreciation regulations would cause the optimal allocation to shift from Expenditure Pattern 4 to Expenditure Pattern 5. Thus, exploration expenditures would remain the same, development expenditures would decrease, and reserves would decline from +0.13% to +0.04%. For the 60% firm, such changes would cause the optimum to shift from Expenditure Pattern 1 to Expenditure Pattern 5. Thus, both exploration and development expenditures would decrease, with the percentage decline for development exceeding that for exploration, as for the 100% firm. This decrease in expenditures would cause reserves to decrease from +7.38% to +0.04%. The initial shock of decreased reserves should affect production restrictions. When productive capacity is decreased by the decline in expenditures, the number of days allowable should ultimately be increased, increasing, in time, the discounted profits and reserves of producing wells. This increase in discounted profits and reserves should make investment more attractive. Therefore, the long run effect of the tax regulation changes on the reserve level would not be as drastic as implied by the original decline from +7.38% to +0.04%. Thus, assuming that the refining-producing firm can pass along (either forward or backward) a part of the tax increase caused by the changes, the simulation results would indicate a relative decrease in development expenditures and a decrease in reserves, with exploration expenditures remaining constant for the 100% firm and decreasing for the 60% firm.

TABLE 10.1
COMPARISON OF DISCOUNTED PROFITS AND RESERVES FOR NINE EXPENDITURE PATTERNS FOR VARIOUS TAX TREATMENTS BY TYPE OF FIRM
(MILLIONS OF DOLLARS)

Domestic Crude Supplied by Own Production	Tax Treatment	Expenditure Pattern 1	2	3	4	5	6	7	8	9
100%	TO1	776.664	775.744	773.124	783.630*	783.244**	776.721	777.027	773.617	769.133
	TO2	530.436	532.586	533.213	541.079	543.116*	540.956	539.251	541.154**	540.090
	TO3	777.993	777.911	776.038	784.838**	785.215*	779.344	778.127	775.384	771.495
	TO4	531.765	534.753	536.127	542.287	545.072*	543.579**	542.190	542.922	542.452
60%	TO5	517.351*	513.952	509.763	517.285**	515.157	511.362	511.490	509.503	506.812
	TO6	367.645	367.015	365.603	371.132**	371.220*	369.924	370.004	370.043	369.404
	TO7	518.148*	515.252	511.511	518.010**	516.330	512.935	512.150	510.563	508.229
	TO8	368.442	368.315	367.351	371.857**	372.394*	370.595	370.664	371.103	370.826

* Best of each simulation.
** Second best of each simulation.
See Figure 12.1.

TABLE 10.2

CONSAD T01 10 10 1968 REPORT A

SUMMARY OF SELECTED VARIABLES FOR SIMULATION RUNS
CONSAD MICRO MODEL OF CRUDE OIL MARKET OF UNITED STATES
OFFICE OF TAX ANALYSIS
U.S. TREASURY DEPARTMENT

10.12

RUN NUMBER	PERCENTAGE CHANGE CRUDE OIL RESERVES	CRUDE PRODUCTION (1000 OF BARRELS)	TOTAL PROFITS AND TAXES (1000 OF DOLLARS) PROFITS	TAX PAYMENTS	INCOME TAXES/ GROSS PROFITS	DISCOUNTED VALUE PROFITS (1000 OF DOLLARS)	RESERVES
1	10.05	503423.	558183.	214509.	.278	433883.	342782.
2	9.94	504091.	575728.	229434.	.285	446361.	320384.
3	9.89	504464.	598950.	242576.	.291	457245.	314880.
4	.13	503932.	592905.	237774.	.286	456413.	325218.
5	.01	504690.	608289.	251187.	.292	469701.	313543.
6	1.02	498619.	612931.	258859.	.297	473360.	303362.
7	-8.53	503719.	621916.	258118.	.293	479640.	297387.
8	-7.52	497558.	626468.	265764.	.298	483226.	290341.
9	-6.53	491898.	630203.	272458.	.302	486240.	282964.

TABLE 10.3

CONSAD T02 10 10 1968 — REPORT A

SUMMARY OF SELECTED VARIABLES FOR SIMULATION RUNS
CONSAD MICRO MODEL OF CRUDE OIL MARKET OF UNITED STATES
OFFICE OF TAX ANALYSIS
U.S. TREASURY DEPARTMENT

RUN NUMBER	PERCENTAGE CHANGE CRUDE OIL RESERVES	CRUDE PRODUCTION (1000 OF BARRELS)	TOTAL PROFITS AND TAXES (1000 OF DOLLARS) PROFITS	TAX PAYMENTS	INCOME TAXES/ GROSS PROFITS	DISCOUNTED VALUE (1000 OF DOLLARS) PROFITS	RESERVES
1	10.05	503423.	349413.	423279.	.546	272639.	257758.
2	9.94	504091.	366682.	438481.	.545	284923.	247644.
3	9.85	504464.	381749.	451777.	.542	295701.	237512.
4	.13	503932.	383528.	446755.	.536	297022.	244057.
5	.04	504511.	398790.	460266.	.536	307936.	235181.
6	1.05	498370.	405916.	465378.	.534	313283.	227474.
7	-8.59	503986.	404752.	459813.	.532	312472.	226780.
8	-7.45	497310.	419892.	471844.	.529	323445.	217716.
9	-6.54	491650.	425975.	476191.	.528	326070.	212020.

TABLE 10.4

CONSAD T03 10 10 1968 REPORT 8

SUMMARY OF SELECTED VARIABLES FOR SIMULATION RUNS
CONSAD MICRO MODEL OF CRUDE OIL MARKET OF UNITED STATES
OFFICE OF TAX ANALYSIS
U.S. TREASURY DEPARTMENT

RUN NUMBER	PERCENTAGE CHANGE CRUDE OIL RESERVES	CRUDE PRODUCTION (1000 OF BARRELS)	TOTAL PROFITS AND TAXES (1000 OF DOLLARS) PROFITS	TAX PAYMENTS	INCOME TAXES/ GROSS PROFITS	DISCOUNTED VALUE (1000 OF DOLLARS) PROFITS	RESERVES
1	10.05	503423.	539394.	233298.	.302	417178.	360816.
2	9.94	504091.	561066.	244096.	.303	432673.	345238.
3	9.83	504464.	579851.	253675.	.304	446188.	320951.
4	.13	503932.	577081.	253199.	.305	444201.	340638.
5	.00	504711.	596423.	263032.	.306	456116.	327100.
6	1.02	498619.	604138.	267651.	.307	464069.	315275.
7	-8.55	503719.	609356.	270677.	.308	467578.	310549.
8	-7.52	497558.	616978.	275254.	.309	473455.	301929.
9	-6.59	491898.	623352.	279309.	.309	476461.	293035.

TABLE 10.5

CONSAD T04 10 10 1968 REPORT 8

SUMMARY OF SELECTED VARIABLES FOR SIMULATION RUNS
CONSAD MICRO MODEL OF CRUDE OIL MARKET OF UNITED STATES
OFFICE OF TAX ANALYSIS
U.S. TREASURY DEPARTMENT

RUN NUMBER	PERCENTAGE CHANGE CRUDE OIL RESERVES	CRUDE PRODUCTION (1000 OF BARRELS)	TOTAL PROFITS AND TAXES (1000 OF DOLLARS) PROFITS	TOTAL PROFITS AND TAXES (1000 OF DOLLARS) TAX PAYMENTS	INCOME TAXES/ GROSS PROFITS	DISCOUNTED VALUE (1000 OF DOLLARS) PROFITS	DISCOUNTED VALUE (1000 OF DOLLARS) RESERVES
1	10.05	503423.	330624.	442068.	.572	255933.	275832.
2	9.94	504091.	352028.	453143.	.563	271235.	263519.
3	9.85	504464.	370650.	462877.	.555	284644.	251484.
4	.13	503932.	368108.	462180.	.557	282810.	250477.
5	.04	504511.	386928.	472128.	.550	296354.	248718.
6	1.05	498370.	397123.	474171.	.544	303993.	230587.
7	-8.49	503362.	400122.	479199.	.545	305979.	236211.
8	-7.48	497310.	410402.	481334.	.540	313673.	229248.
9	-6.54	491650.	419124.	483041.	.535	320291.	222161.

TABLE 10.6

CONSAD T05 10 10 1964 REPORT 8

SUMMARY OF SELECTED VARIABLES FOR SIMULATION RUNS
CONSAD MICRO MODEL OF CRUDE OIL MARKET OF UNITED STATES
OFFICE OF TAX ANALYSIS
U.S. TREASURY DEPARTMENT

RUN NUMBER	PERCENTAGE CHANGE CRUDE OIL RESERVES	CRUDE PRODUCTION (1000 OF BARRELS)	TOTAL PROFITS AND TAXES (1000 OF DOLLARS) PROFITS	TAX PAYMENTS	INCOME TAXES/ GROSS PROFITS	DISCOUNTED VALUE (1000 OF DOLLARS) PROFITS	RESERVES
1	7.34	311810.	407034.	198411.	.328	314826.	202524.
2	8.54	307529.	411135.	204449.	.332	317026.	194059.
3	9.64	303530.	414470.	209701.	.336	320495.	189268.
4	-1.03	306782.	420306.	209046.	.332	324563.	192722.
5	.00	302840.	423720.	214335.	.336	327186.	187971.
6	1.02	299155.	426468.	218930.	.339	329348.	182913.
7	-8.53	302150.	431769.	218445.	.336	333058.	178442.
8	-7.52	298519.	434590.	223073.	.339	335268.	174234.
9	-6.53	295123.	436831.	227090.	.342	337076.	169736.

[redacted]

TABLE 10.7

CONSAD T06 10 10 1968 REPORT 8

SUMMARY OF SELECTED VARIABLES FOR SIMULATION RUNS
CONSAD MICRO MODEL OF CRUDE OIL MARKET OF UNITED STATES
OFFICE OF TAX ANALYSIS
U.S. TREASURY DEPARTMENT

RUN NUMBER	PERCENTAGE CHANGE CRUDE OIL RESERVES	CRUDE PRODUCTION (1000 OF BARRELS)	TOTAL PROFITS AND TAXES (1000 OF DOLLARS) PROFITS	TAX PAYMENTS	INCOME TAXES/ GROSS PROFITS	DISCOUNTED VALUE PROFITS (1000 OF DOLLARS)	RESERVES
1	7.39	311677.	277595.	327581.	.541	215218.	152426.
2	8.57	307396.	283475.	331843.	.539	216525.	147464.
3	9.69	303396.	288468.	335437.	.538	223229.	142374.
4	-1.05	306649.	292956.	336131.	.534	226372.	144760.
5	.84	302707.	298005.	339784.	.533	230132.	141109.
6	1.05	299022.	302780.	342852.	.531	233320.	134606.
7	-8.47	302017.	306340.	343608.	.529	236175.	133825.
8	-7.49	298586.	310666.	346731.	.527	239437.	130620.
9	-6.54	294990.	314315.	349339.	.526	242192.	127212.

10.12

TABLE 10.8

CONSAD T07 10 18 1968 REPORT 8

SUMMARY OF SELECTED VARIABLES FOR SIMULATION RUNS
CONSAD MICRO MODEL OF CRUDE OIL MARKET OF UNITED STATES
OFFICE OF TAX ANALYSIS
U.S. TREASURY DEPARTMENT

RUN NUMBER	PERCENTAGE CHANGE CRUDE OIL RESERVES	CRUDE PRODUCTION (1000 OF BARRELS)	TOTAL PROFITS AND TAXES (1000 OF DOLLARS) PROFITS	TAX PAYMENTS	INCOME TAXES/ GROSS PROFITS	DISCOUNTED VALUE (1000 OF DOLLARS) PROFITS	RESERVES
1	7.34	311810.	395761.	209685.	.346	304803.	213345.
2	8.53	307229.	402338.	213246.	.346	309711.	205542.
3	9.64	303530.	407810.	216361.	.347	313860.	197651.
4	-1.07	306782.	411051.	218381.	.347	316036.	201974.
5	.08	302840.	416603.	221452.	.347	320237.	194065.
6	1.02	299155.	421197.	224206.	.347	323774.	189141.
7	-8.53	302150.	424233.	225981.	.348	325821.	184336.
8	-7.52	298519.	428896.	228767.	.348	329405.	181157.
9	-6.53	295123.	432721.	231200.	.348	332409.	175821.

TABLE 10.9

CONSAD T08 10 10 1968 REPORT 8

SUMMARY OF SELECTED VARIABLES FOR SIMULATION RUNS
CONSAD MICRO MODEL OF CRUDE OIL MARKET OF UNITED STATES
OFFICE OF TAX ANALYSIS
U.S. TREASURY DEPARTMENT

RUN NUMBER	PERCENTAGE CHANGE CRUDE OIL RESERVES	CRUDE PRODUCTION (1000 OF BARRELS)	TOTAL PROFITS AND TAXES (1000 OF DOLLARS) PROFITS	TAX PAYMENTS	INCOME TAXES/ GROSS PROFITS	DISCOUNTED VALUE (1000 OF DOLLARS) PROFITS	RESERVES
1	7.38	311677.	266326.	338854.	.560	205195.	163247.
2	8.57	307396.	274478.	340640.	.554	211313.	157003.
3	9.69	303396.	281609.	342096.	.548	216595.	150757.
4	-1.05	306649.	283701.	345385.	.549	217845.	154012.
5	.04	302707.	290688.	346902.	.544	223163.	149231.
6	-6.44	298768.	304540.	351836.	.536	232919.	137476.
7	-8.49	302017.	298804.	351144.	.540	226938.	141727.
8	-7.43	298386.	304972.	352425.	.536	233554.	137549.
9	-6.55	295018.	310168.	353442.	.533	237495.	133331.

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TABLE A.1

U.S. Crude Petroleum Industry Well-Head Value of Oil and Gas Production (GIN)			
Year	Chase Bank Group	All Other	U.S. Total
	MILLION DOLLARS		
1946	1353	905	2258
1947	1977	1298	3275
1948	2899	1844	4743
1949	2560	1722	4282
1950	2660	1905	4565
1951	3112	2187	5299
1952	3244	2204	5448
1953	3695	2340	6035
1954	3752	2460	6212
1955	3930	2741	6671
1956	4231	2897	7128
1957	4759	3134	7893
1958	4377	3011	7388
1959	4540	3127	7667
1960	4660	3163	7823
1961	4803	3339	8142
1962	4960	3464	8424
1963	5277	3466	8743
1964	5372	3487	8859
1965	5652	3513	9165

Sources: Factors Affecting U.S. Exploration, Development and Production 1946-1965; National Petroleum Council, 1967. Some data may be derived from original data.

TABLE A.2

U.S. Crude Petroleum Industry Exploration and Development Expenditures Summed Over Three Years (STEP)			
Year	Chase Bank Group	All Other	U.S. Total
	MILLION DOLLARS		
1946			
1947			
1948	3084	2681	5765
1949	3526	2030	6465
1950	3692	3148	6840
1951	3994	3521	7515
1952	4632	4293	8925
1953	5489	5086	10575
1954	6049	5851	11900
1955	6577	6373	12950
1956	7183	6866	14050
1957	7677	7173	14850
1958	7535	6865	14400
1959	7369	6306	13675
1960	7108	5667	12775
1961	7284	5266	12550
1962	7677	4948	12625
1963	7717	4833	12550
1964	8117	4883	13000
1965	8116	4669	12785

Sources: Factors Affecting U.S. Exploration, Development and Production 1946-1965; National Petroleum Council, 1967. Some data may be derived from original data.

TABLE A.3

U.S. Crude Petroleum Industry
Rate of Return[a]
(GIN-EPPR)
STEP

Year	Chase Bank Group	All Other	U.S. Total
1946			
1947			
1948	.7911	.5871	.6963
1949	.6554	.5335	.6000
1950	.6414	.5419	.5956
1951	.6522	.5254	.5928
1952	.5840	.4312	.5105
1953	.5245	.3697	.4499
1954	.4723	.3283	.4015
1955	.4479	.3325	.3911
1956	.4346	.3213	.3792
1957	.4231	.3110	.3690
1958	.4123	.3237	.3701
1959	.4496	.3771	.4162
1960	.4844	.4314	.4609
1961	.4861	.4922	.4887
1962	.4711	.5487	.5015
1963	.5020	.5609	.5247
1964	.4852	.5622	.5140
1965	.5129	.5988	.5443

[a]Rate of Return: (Well-Head Value of Oil and Gas minus production expenditures) divided by the summed three years exploration and development expenditures.

Sources: Factors Affecting U.S. Exploration, Development and Production 1946-1965; National Petroleum Council, 1967. Some data may be derived from original data.

TABLE A.4

U.S. Crude Petroleum Industry Return[a] (GIN-EPPR)			
Year	Chase Bank Group	All Other	U.S. Total
	MILLION DOLLARS		
1946			
1947			
1948	2440	1574	4014
1949	2311	1568	3879
1950	2368	1706	4074
1951	2605	1850	4455
1952	2705	1851	4556
1953	2879	1879	4758
1954	2857	1921	4778
1955	2946	2119	5065
1956	3122	2206	5328
1957	3248	2231	5479
1958	3107	2222	5329
1959	3313	2378	5691
1960	3443	2445	5888
1961	3541	2592	6133
1962	3617	2715	6332
1963	3874	2711	6585
1964	3938	2745	6682
1965	4163	2796	6959

[a]Return: Well-Head Value of Oil and Gas Production minus production expenditures.

Sources: Factors Affecting U.S. Exploration, Development and Production 1946-1965: National Petroleum Council, 1967. Some data may be derived from original data.

TABLE A.5

U.S. Crude Petroleum Industry
Production Expenditures[a]
(-6907 + (. 00114)PROD + (2051)PR)

Year	Chase Bank Group	All Other	U.S. Total
	MILLION DOLLARS		
1946			
1947			
1948	459	270	729
1949	249	154	403
1950	292	199	491
1951	507	337	844
1952	539	353	892
1953	816	461	1277
1954	895	539	1434
1955	984	622	1606
1956	1109	691	1800
1957	1511	903	2414
1958	1270	789	2059
1959	1227	749	1976
1960	1217	718	1935
1961	1262	747	2009
1962	1343	749	2092
1963	1403	755	2158
1964	1434	742	2177
1965	1489	717	2206

[a]Production expenditures are estimated by the following equation: -607 +(.00114) production + (2051) Price of Crude Oil.

Sources: Factors Affecting U.S. Exploration, Development and Production 1946-1965; National Petroleum Council, 1967. Some data may be derived from original data.

TABLE A.6

U.S. Crude Petroleum Industry
Rate of Return[a]
$\left(\frac{GIN-EPPR}{TEP}\right)$

Year	Chase Bank Group	All Other	U.S. Total
1946			
1947			
1948	1.8210	1.6029	1.745
1949	1.8989	1.5711	1.7512
1950	2.0467	1.4581	1.7523
1951	1.6080	1.3653	1.4975
1952	1.4582	1.0458	1.2568
1953	1.4295	.9582	1.1970
1954	1.3105	.9061	1.1111
1955	1.2363	.9245	1.0834
1956	1.1911	.8989	1.0499
1957	1.2151	.9192	1.0743
1958	1.3864	1.1200	1.2613
1959	1.3495	1.2549	1.3083
1960	1.4274	1.3674	1.4190
1961	1.4650	1.6374	1.5333
1962	1.2700	1.7216	1.4310
1963	1.5799	1.6204	1.5964
1964	1.3979	1.6810	1.5016
1965	1.4622	2.051	1.6530

[a]Rate of return: (Well-Head Value of Oil and Gas Production minus production expenditures) divided by the annual expenditures for exploration and development.

Sources: Factors Affecting U.S. Exploration, Development and Production 1946-1965 National Petroleum Council, 1967. Some data may be derived from original data.

TABLE A.7

U.S. Crude Petroleum Industry
Rate of Growth of Receipts[a]

$$\left(\frac{GIN(t)}{GIN(t-1)}\right)$$

Year	Chase Bank Group	All Other	U.S. Total
1946			
1947			
1948			
1949	.9471	.9962	.9663
1950	1.0247	1.0880	1.0503
1951	1.1001	1.0844	1.0935
1952	1.0383	1.0005	1.0227
1953	1.0643	1.0151	1.0443
1954	.9924	1.0224	1.0042
1955	1.0312	1.1031	1.0601
1956	1.0597	1.0411	1.0519
1957	1.0404	1.0113	1.0283
1958	.9565	.9959	.9726
1959	1.0663	1.0702	1.0679
1960	1.0392	1.0281	1.0346
1961	1.0285	1.0601	1.0416
1962	1.0215	1.0475	1.0324
1963	1.0711	.9985	1.0400
1964	1.0165	1.0125	1.0147
1965	1.0571	1.0186	1.0415

[a]Rate of Growth of Receipts: Present annual well-head value of oil and gas production divided by the previous year's value.

Sources: Factors Affecting U.S. Exploration, Development and Prod[illegible]-1965; National Petroleum Council, 1967. Some data may be derived from original

TABLE A. 8

U.S. Crude Petroleum Industry ANNUAL CRUDE PRODUCTION (PROD)				
Year	Price Dollars	Chase Bank Group	All Other	U.S. Total
		THOUSANDS OF BARRELS		
1946				
1947				
1948	2.60	1,270,752	749,568	2,020,320
1949	2.54	1,138,070	703,720	1,841,790
1950	2.51	1,174,205	799,350	1,973,555
1951	2.53	1,351,230	896,440	2,247,670
1952	2.53	1,383,114	906,582	2,289,696
1953	2.68	1,506,353	850,815	2,357,170
1954	2.78	1,443,575	871,255	2,314,830
1955	2.77	1,523,145	961,410	2,484,555
1956	2.79	1,612,596	1,004,670	2,617,266
1957	3.09	1,637,755	979,295	2,617,050
1958	3.01	1,511,465	937,685	2,449,150
1959	2.90	1,598,335	976,375	2,574,710
1960	2.88	1,618,818	955,992	2,574,810
1961	2.89	1,646,150	975,645	2,621,795
1962	2.90	1,717,690	958,490	2,676,180
1963	2.89	1,790,325	962,505	2,752,830
1964	2.88	1,836,222	950,502	2,786,724
1965	2.86	1,923,185	925,275	2,848,460

Sources: Factors Affecting U.S. Exploration, Development and Production 1946-1965, National Petroleum Council, 1967. Some data may be derived from original data.

TABLE A.9

U.S. Crude Petroleum Industry

EXPENDITURES FOR EXPLORATION AND DEVELOPMENT (TEP)

Year	Chase Bank Group	All Other	U.S. Total
	MILLION DOLLARS		
1946	775	740	1515
1947	991	959	1950
1948	1318	982	2300
1949	1217	998	2215
1950	1157	1168	2325
1951	1620	1355	2975
1952	1855	1770	3625
1953	2014	1961	3975
1954	2180	2120	4300
1955	2383	2292	4675
1956	2621	2454	5075
1957	2673	2427	5100
1958	2241	1984	4225
1959	2455	1895	4350
1960	2412	1788	4200
1961	2417	1583	4000
1962	2848	1577	4425
1963	2452	1673	4125
1964	2817	1633	4450
1965	2847	1363	4210

Sources: Factors Affecting U.S. Exploration, Development and Production 1946-1965; National Petroleum Council, 1967. Some data may be derived from original data.

TABLE A. 10

U.S. Crude Petroleum Industry RATE OF RETURN FROM RECEIPTS				
GIN = Gross income from mineral production excluding royalties (well-head value of production) (Million dollars) TEP = Expenditures for exploration and development (Million dollars) TEPT= Expenditures for exploration, development and production (Million dollars)				
Year	GIN	TEP	GIN-TEP	$\frac{\text{GIN-TEP}}{\text{TEP}}$
1955	6872	4246	2626	.61846
1956	7320	4553	2767	.60773
1959	7930	4375	3605	.83353
1960	8090	4127	3963	1.04853
1961	8412	3921	4491	1.14537
1962	8724	4590	4134	.90065
1963	9073	3884	5189	1.33599
1964	9161	4302	4859	1.12948
1965	9367	4104	5263	1.28241
	GIN	TEPT	GIN-TEPT	$\frac{\text{GIN-TEPT}}{\text{TEPT}}$
1955	6872	5853	1010	.17410
1956	7320	6331	989	.15622
1959	7930	6283	1644	.26166
1960	8090	6055	2035	.33609
1961	8412	5917	2495	.42167
1962	8724	6681	2043	.30579
1963	9073	6036	3037	.50315
1964	9161	6512	2649	.40679
1965	9367	6401	2966	.46337

Sources: Income and expenditures Joint Association Annual Surveys; Reserve data and prices from Facts and Figures, American Petroleum Institute.

TABLE A.11

U.S. Crude Petroleum Industry RATE OF RETURN FROM NEW RESERVES	
EPEL	= Expenditure for exploration (Million dollars)
EPDV	= Expenditures for development (Million dollars)
NRE	= New reserves from exploration (Thousands of Barrels)
NRD	= New reserves from development (Thousands of Barrels)
PR	= Price (Dollars)

Year	NRE	NRD	PR	NRE·PR	NRD·PR
1955	476,957	2,393,767	2.77	1,321,170	6,630,735
1956	467,222	2,507,114	2.79	1,274,049	6,994,848
1959	369,362	3,217,383	2.90	1,071,150	9,562,411
1960	253,856	2,111,472	2.88	731,105	6,081,039
1961	361,374	2,296,193	2.89	1,044,371	6,635,998
1962	380,586	1,800,310	2.90	1,103,699	5,220,899
1963	349,891	1,824,219	2.89	1,011,185	5,271,993
1964	346,293	2,318,474	2.88	997,324	6,677,205
1965	471,947	2,576,132	2.86	1,349,768	7,367,738

Year	EPEL	EPDV	$\frac{NRE \cdot PR}{EPEL}$	$\frac{NRD \cdot PR}{EPDV}$
1955	1,944	2,252	.67961	2.9444
1956	2,117	2,436	.61126	2.8714
1959	2,012	2,313	.53238	4.1342
1960	2,045	2,082	.35751	2.9208
1961	1,851	2,070	.56422	3.2058
1962	2,324	2,266	.47491	2.3040
1963	1,845	2,039	.54807	2.5856
1964	2,109	2,193	.47289	3.0448
1965	1,971	2,133	.68481	3.4542

Sources: Income and expenditure Joint Association Annual Surveys; Reserve data and prices from Facts and Figures, American Petroleum Institute.

TABLE A. 12

CUMULATIVE DISTRIBUTION OF
PERCENTAGE DEPLETION BY RATIO OF PERCENTAGE
DEPLETION TO POSITIVE NET INCOMES
FOR DOMESTIC PROPERTIES

CPNIL $(.6, .275, t)_i$

Percentage Depletion Claimed as a Percent of Net Income	i	Cumulative Distribution 1958	1959	1960
0	0	.000	.000	.000
0 < .099	.1	.000	.000	.002
.100 ≤ .199	.2	.001	.001	.004
.200 ≤ .299	.3	.012	.017	.013
.300 ≤ .399	.4	.715	.532	.497
.400 ≤ .499	.5	.987	.984	.984
.500 +	.6	1.000	1.000	1.000

TABLE A.13

ESTIMATED TOTAL DOMESTIC DEPLETION CLAIMED

Year	Depletion Claimed: Foreign and Domestic			Estimated Domestic Depletion Total
	Refining	Crude	Total	
	(Thousands of Dollars)			PPD(t)
1951	891,723	432,152	1,323,875	
1952	910,989	480,613	1,391,602	
1953	1,010,589	514,214	1,524,803	
1954	1,064,213	406,088	1,470,301	
1955-56	1,265,940	473,728	1,739,668	
1956-57	1,374,548	474,607	1,849,155	
1957-58	1,595,563	526,729	2,122,292	1,435,518
1958-59	1,522,549	510,743	2,033,292	1,375,319
1959-60	1,527,908	526,403	2,054,311	1,389,536
1960-61	1,644,951	569,382	2,213,333	1,497,775
1961-62	1,694,327	624,846	2,319,173	1,568,689
1962-63	1,836,647	625,833	2,462,480	1,665,621
1963				1,757,650

Source: Corporate Statistics of Income.

TABLE A. 14

ESTIMATED DOMESTIC COST DEPLETION AS A PERCENT OF TOTAL DOMESTIC DEPLETION

CD(t)

Year t	5%	10%	15%	20%	25%
		(Thousands	of Dollars)		
1957	71,776	143,552	215,328	287,104	358,880
1958	68,766	137,532	206,720	275,064	342,830
1959	69,477	138,954	208,431	277,908	347,385
1960	74,889	149,778	224,667	299,556	374,445
1961	78,435	156,869	235,304	313,738	392,173
1962	83,281	166,562	249,843	333,124	416,405
1963	87,882	175,765	263,647	351,530	439,412

Source: Derived from Table A. 13.

TABLE A.15

U.S. CRUDE PETROLEUM INDUSTRY SUM OF EIGHT YEARS EXPENDITURES FOR EXPLORATION AND DEVELOPMENT (TTEP)			
Year	Chase Bank Group	All Other	U.S. Total
1953	10,947	9,933	20,880
1954	12,352	11,313	23,665
1955	13,744	12,646	26,390
1956	15,074	14,118	29,165
1957	16,503	15,547	32,050
1958	17,587	16,363	33,950
1959	18,422	16,903	35,325
1960	18,979	16,921	35,900
1961	19,382	16,524	35,925
1962	20,050	16,000	36,050
1963	20,119	15,381	35,500
1964	20,315	14,560	34,875
1965	20,489	13,496	33,985

Sources: Factors Affecting U.S. Exploration, Development and Production 1946-1965; National Petroleum Council, 1967. Some data may be derived from original data.

TABLE A.16

U.S. CRUDE PETROLEUM INDUSTRY
RATE OF RETURN[a]
$\left(\frac{GIN-EPPR}{TTEP}\right)$

Year	Chase Bank Group	All Other	U.S. Total
1953	.2629	.1891	.2278
1954	.2312	.1698	.2019
1955	.2143	.1675	.1919
1956	.2071	.1562	.1826
1957	.1968	.1435	.1709
1958	.1766	.1357	.1569
1959	.1798	.1407	.1611
1960	.1814	.1445	.1640
1961	.1826	.1568	.1707
1962	.1803	.1696	.1756
1963	.1925	.1762	.1854
1964	.1938	.1885	.1915
1965	.2031	.2071	.2047

[a]Rate of Return: (Well-Head Value of Oil and Gas minus production expenditure divided by the summed eight years exploration and development expenditures.

Sources: Factors Affecting U.S. Exploration, Development, and and Production 1946-1965; National Petroleum Council, 1967.

TABLE A.17
ESTIMATES OF RATES OF RETURN IN PETROLEUM
DOMESTIC AND FOREIGN OPERATIONS

	MCDONALD		STIGLER			SIMON		
	(1) Petroleum Integrated	(2) Gas & Oil Production	(3) Petroleum Refining	(4) Petroleum Refining Book Values	(5) Petroleum Refining[a]	(6) Petroleum Refining	(7) Crude Petroleum	(8) Crude & Refining
1938	5.0	6.5	1.29		0.79			
1939	5.4	4.8	3.08		2.49			
1940	5.4	4.3	3.68		2.90			
1941	9.9	8.3	5.06		3.70			
1942	7.0	9.0	5.21		3.52			
1943	7.9	10.8	6.65		4.26			
1944	9.7	12.5	5.84		3.74			
1945	8.4	13.2	4.45		2.65			
1946	10.7	12.6	6.50		3.96			
1947	15.8	19.9		9.17	5.49			
1948	22.1	35.9		11.85	7.21	8.14	10.79	8.59
1949	13.2	21.7		7.05	3.80	5.42	8.68	6.04
1950	14.9	18.3		8.59	5.35	6.84	9.43	7.37
1951	16.5	19.5		8.28	4.78	7.23	9.35	7.65
1952	14.4	16.3		N.A.	3.71	N.A.	N.A.	N.A.
1953	14.3	16.4		7.11	4.43	6.32	9.96	7.01
1954	13.7	15.3		5.68	3.41	5.46	8.46	5.93
1955	14.1	16.2		7.09	4.73	6.32	8.85	6.73
1956	14.6	16.0		6.88	4.34	6.11	8.48	6.47
1957	13.4	16.5		6.46	3.70	5.85	8.91	6.32
1958	10.1	11.8			2.54	5.18	7.22	5.49
1959	9.9	12.2				5.17	7.22	5.48
1960	10.1	12.5				4.96	7.20	5.31
1961	10.3	12.7				4.93	7.52	5.35

[a] 1947 Constant Prices

Sources: 1 and 2 — Federal Tax Treatment of Income From Oil & Gas. pg. 142.
3, 4, 5 — Capital & Rates of Return in Manufacturing Industries, pg. 153, 184.
6, 7, 8 — Figures supplied by Simon M. Simon, Graduate School of Business Administration, New York University
(See following page)

NOTE ON COMPUTATION OF COMPARATIVE RATES OF RETURN PREPARED BY SIMON M. SIMON

The Rates of Return are not absolute but rather computed to serve for comparative purposes. They are based on balance sheets and profit and loss statements compiled by IRS in the Source Book for respective years.

The data in Source Books were further adjusted so as to eliminate certain factors or privileges in one industry, and make the data more comparable. For instance, the rate of return is figured on gross assets invested in the business and as such rented assets should be included. Thus, some adjustments were made to convert rentals paid to respective value of the asset rented.

Similar adjustments were made for depreciation and depletion. For the years 1954 and over, depreciation was normalized to reflect the straightline method, and the excess depreciation was added back to profits. Similarly, excess depletion based on the Treasury survey of 1958, 1959, and 1960 was added back to income.

TABLE A. 18
COMPARISON OF ESTIMATES OF RATES OF RETURN IN INDUSTRIES OTHER THAN PETROLEUM

	MCDONALD		STIGLER		SIMON		
	(1) Manufacturing	(2) Mining	(3) Total Manufacturing 1947 Prices	(4) Total Manufacturing Book Values	(5) Electric & Gas	(6) Manufacturing (Other than Petroleum)	(7) Total Manufacturing
1938	4.6	4.2	2.63	2.62			
1939	8.3	4.8	5.77	6.00			
1940	10.5	6.3	6.95	7.12			
1941	12.3	6.8	8.36	8.56			
1942	9.9	7.4	6.95	7.30			
1943	9.6	7.2	6.80	7.30			
1944	9.6	8.0	6.20	6.59			
1945	9.3	7.1	5.26	5.43			
1946	12.1	9.4	7.65	8.13			
1947	17.1	16.0	9.84[a]	10.34			
1948	18.2	20.5	10.05	10.43	3.80	8.52	8.23
1949	13.9	12.0	7.92	7.93	3.87	6.76	6.37
1950	17.1	13.2	9.99	9.97	3.80	9.21	8.60
1951	14.4	13.0	7.78	7.34	3.75	7.68	7.39
1952	12.3	10.1	6.46	5.96	N.A.	N.A.	N.A.
1953	12.7	7.9	6.54	6.05	3.90	6.65	6.39
1954	12.3	8.2	6.26	5.68	3.91	5.97	5.90
1955	14.9	13.0	7.97	7.47	4.49	7.61	7.06
1956	13.8	13.8	7.71	6.85	4.63	6.86	6.53
1957	12.9	9.6	7.40	6.29	4.38	6.42	6.14
1958	9.8	7.3			4.40	5.29	5.27
1959	11.7	7.8			4.60	6.24	6.03
1960	10.6	8.0			4.31	5.44	5.35
1961	10.1	8.6			4.63	5.28	5.25

Sources:

1, 2 Federal Tax Treatment of Oil & Gas P. 142; McDonald

3, 4 Capital & Rates of Return in Manufacturing Industries p. 169, 202; Stigler

5, 6, 7 Figures supplied by Simon M. Simon

[a] The industry definition was changed in 1947.

TABLE A. 19
U.S. DOMESTIC DRILLING

Year	All Wells Completed					Exploratory Wells				New Field Wildcats				Producing Oil Wells End of Year
	Oil	Gas	Dry	Total	Successful	Producers	Dry	Total	Successful	Producers	Dry Holes	Total	% Successful	
1943	9,71[illegible]	1,782	6,385	19,431	64.30	714	3,294	4,008	17.8					407,170
1944	13,028	3,067	7,009	25,260	69.66	944	3,852	4,796	19.6	342	2,752	3,094	11.0	412,220
1945	14,297	2,898	7,471	26,875	69.71	1,214	4,399	5,613	21.6	352	2,685	3,037	11.5	415,750
1946	15,851	3,090	8,047	29,225	70.18	1,137	4,622	5,759	19.7	333	2,800	3,133	10.6	421,460
1947	17,961	3,307	9,625	33,173	68.84	1,378	5,397	6,775	20.3	394	3,086	3,480	11.3	426,280
1948	22,340	2,906	12,112	39,628	67.58	1,463	6,550	8,013	18.2	501	3,795	4,296	11.6	437,880
1949	21,905	2,886	12,842	39,015	65.88	1,830	7,228	9,058	20.2	506	3,943	4,449	11.3	448,680
1950	24,416	2,837	14,786	43,287	64.83	2,014	8,292	10,306	19.5	592	4,698	5,290	11.1	465,870
1951	23,437	3,027	16,704	44,545	61.30	2,217	9,539	11,756	18.8	684	5,505	6,189	11.0	474,990
1952	23,448	3,246	17,714	45,895	60.11	2,335	10,090	12,425	18.7	741	5,957	6,698	11.0	488,520
1953	25,748	3,801	18,509	49,325	61.49	2,680	10,633	13,313	20.1	774	6,151	6,925	11.1	498,940
1954	29,776	3,974	19,285	54,051	63.64	2,708	10,389	13,097	20.6	902	6,478	7,380	12.2	511,200
1955	31,540	3,614	20,742	56,666	62.89	3,105	11,832	14,937	20.7	918	7,186	8,104	11.3	524,010
1956	31,196	4,115	21,871	58,259	61.75	3,096	13,077	16,173	19.1	868	7,841	8,709	9.9	551,170
1957	28,272	3,914	20,762	54,017	60.88	2,810	11,897	14,707	19.1	872	7,142	8,014	10.8	569,273
1958	25,270	3,679	18,823	49,142	60.69	2,567	10,632	13,199	19.4	786	6,164	6,950	11.3	574,905
1959	25,802	5,039	19,277	51,812	61.54	2,614	10,577	13,191	19.8	772	6,259	7,031	10.9	583,141
1960	21,214	5,255	17,588	46,810	60.08	2,189	9,515	11,704	18.7	745	6,575	7,320	10.1	591,158
1961	21,170	5,667	17,803	47,018	61.10	1,970	9,022	10,992	17.9	745	6,164	6,909	10.7	594,917
1962	21,385	5,859	16,753	46,422	61.92	1,982	8,815	10,797	18.3	76[illegible]	6,007	6,794	11.5	596,385
1963	20,704	4,758	16,318	44,078	60.94	1,978	8,686	10,664	18.5	769	5,801	6,570	11.7	588,657
1964	20,930	4,871	17,533	45,727	50.54	1,796	8,951	10,747	16.7	701	5,931	6,632	10.5	588,225

Sources: Petroleum Facts & Figures, 1965.

TABLE A. 20

COMPARATIVE FOOTAGE DRILLED EXPLORATORY AND WILDCAT WELLS 1943-1964						
	All Exploratory Wells			Wildcat Wells		
	Footage	Footage Successful	Percent of Footage in Successful W.	Footage	Footage Successful	Percent of Footage in Successful Wells
	Millions of Feet			Millions of Feet		
1943	15,719	2,936	5.4	N A.	N.A.	N.A.
1944	20,225	4,382	4.6	12,997	1,640	6.94
1945	23,030	5,501	4.2	13,368	1,789	6.50
1946	22,197	5,286	4.2	12,555	1,692	6.45
1947	26,393	6,166	4.3	14,617	2,096	6.00
1948	32,741	7,179	4.6	18,740	2,690	6.00
1949	34,798	8,359	4.2	18,159	2,786	5.53
1950	40,175	9,217	4.4	22,118	3,146	6.06
1951	49,343	10,621	4.6	27,948	3,831	6.34
1952	55,615	11,884	4.7	32,501	4,433	6.37
1953	60,702	13,422	4.5	33,855	4,533	6.49
1954	59,581	13,789	4.3	35,484	5,339	5.65
1955	69,173	15,953	4.3	38,970	5,316	6.37
1956	73,981	16,284	4.5	41,922	5,482	6.67
1957	69,136	15,761	4.4	39,050	5,503	6.10
1958	61,483	14,184	4.3	34,202	5,041	5.81
1959	63,252	14,576	4.3	35,459	4,824	6.37
1960	55,830	12,259	4.5	35,881	4,750	6.57
1961	54,472	11,149	4.9	35,410	4,677	6.57
1962	53,574	11,392	4.7	34,884	5,051	5.91
1963	53,485	10,638	5.0	33,551	4,180	7.04
1964	55,496	10,918	5.1	34,585	4,587	6.57

Source: Petroleum Facts and Figures, 1965, p. 13; 1959, p. 17.

TABLE A.21

U.S. DOMESTIC DRILLING
MEAN DEPTH OF WELLS

Year	All Wells - Average Depth: Oil (1)	Gas (2)	Dry (3)	Total (4)	Exploratory Wells Average Depth (5)	New Field Wildcats Average Depth (6)
	(feet)					
1944					4,217	4,200
1945					4,103	4,402
1946					3,854	4,007
1947					3,896	4,200
1948					4,086	4,362
1949					3,842	4,082
1950					3,898	4,177
1951					4,197	4,516
1952					4,476	4,852
1953					4,560	4,889
1954					4,549	4,808
1955	4,010	4,010	4,050	4,030	4,631	4,809
1956	4,070	4,070	4,050	4,065	4,574	4,814
1957					4,701	4,873
1958					4,658	4,921
1959	3,814	5,464	4,240	4,146	4,795	5,043
1960	3,946	5,526	4,168	4,223	4,770	4,902
1961	3,911	5,366	4,284	4,244	4,953	5,125
1962	4,041	5,366	4,533	4,405	4,967	5,135
1963	3,922	5,373	4,556	4,336	5,016	5,108
1964					5,164	5,215

Sources: 1, 2, 3, 4 Joint Association Surveys
5, 6 Petroleum Facts & Figures 1965, p. 13, From American Association of Petroleum Geologists.

TABLE A.22

COMPARATIVE U.S. DOMESTIC DRILLING COSTS AND EXPENDITURES
1953 AND 1963

Depth Range	Number of Wells		Cost Per Foot		Total Expenditures ($1,000)	
	1953	1963	1953	1963	1953	1963
0-1,250	5,001	5,931	$6.63	$8.19	$28,147	40,526
1,251-2,500	10,219	8,419	7.99	8.39	146,368	130,204
2,501-3,750	12,603	8,705	9.10	8.46	357,996	228,803
3,751-5,000	7,442	5,469	10.09	8.87	322,182	212,150
5,001-7,500	8,624	6,622	12.51	10.08	658,545	416,357
7,501-10,000	3,496	3,720	14.86	13.44	448,441	435,623
10,001-12,500	1,414	2,004	20.83	18.00	326,363	402,332
12,501-15,000	447	719	27.15	27.42	162,399	266,365
Over 15,000	33	264	40.20	39.37	21,278	170,503
Total	49,279	41,853	12.43	12.69	2,471,718	2,302,863

Source: Joint Association Survey
1953; 1963.

TABLE A.23

DRILLING STATISTICS FOR OIL, GAS, DRY AND SERVICE WELLS
200 LARGEST COMPANIES AND ALL OTHER COMPANIES

1963

	Well Drilled	Footage Drilled 1,000 ft.	Average Footage Drilled per well	Cost of Drilling & Equipping wells $1,000	Average Cost per foot $	Average per well $
OIL WELLS:						
All Companies	19,837	80,410	4,054	1,048,969	13.1	52,879
200 Largest Companies	9,093	47,700	5,246	790,600	16.1	86,946
All Other Companies	10,744	32,710	3,044	258,369	7.9	24,048
GAS WELLS:						
All Companies	4,578	25,241	5,514	416,062	16.5	90,883
200 Largest Companies	2,283	15,895	6,962	328,131	20.6	143,728
All Other Companies	2,295	9,346	4,072	87,931	9.4	38,314
DRY HOLES:						
All Companies	14,794	69,004	4,664	599,068	8.7	40,494
200 Largest Companies	4,111	28,469	6,925	400,288	14.1	97,370
All Other Companies	[illegible]	40,535	3,794	199,320	4.9	18,658
SERVICE WELLS:						
All Companies	2,634	[illegible]	1,813	34,917	7.2	13,104
200 Largest Companies	1,254	2,761	2,202	25,914	9.4	20,665
All Other Companies	1,380	2,014	[illegible]	8,603	4.3	6,234
TOTAL EXCLUSIVE OF SERVICE WELLS:						
All Companies	[illegible]	174,655	14,232	2,064,099	11.8	52,644
200 Largest Companies	[illegible]	92,064	19,133	1,519,019	16.5	98,082
All Other Companies	[illegible]	82,591	16,184	545,620	6.6	23,001
TOTAL INCLUSIVE OF SERVICE WELLS:						
All Companies	41,843	[illegible]	16,045	[illegible]	11.8	59,155
200 Largest Companies	[illegible]	[illegible]	21,335	[illegible]	16.3	92,289
All Other Companies	[illegible]	[illegible]	17,643	[illegible]	6.6	22,079

Source: Census of Mineral Industries 196[illegible]

TABLE A.24

DRILLING COSTS - U.S. DOMESTIC PETROLEUM INDUSTRY

	Average Cost Per Foot (Dollars)								Average Cost Per Well (Dollars)				Total Drilling Costs (Thousand of Dollars)			
	Oil Wells			Gas Wells												
	Intangible	Tangible	Total	Intangible	Tangible	Total	Total, Dry Holes	Total, All Wells	Oil	Gas	Dry	All	Oil	Gas	Dry	Total
1953								12.43				50,158				2,471,718
1954																
1955							9.21	11.55			37,300	46,500			774,418	2,600,143
1956							10.26	12.35			41,600	50,200			909,861	2,598,410
1957																
1958																
1959	9.42	4.21	13.63	13.33	5.12	18.45	10.13	12.90	52,000	100,700	43,000	53,500	1,321,426	508,895	820,775	2,651,096
1960	9.25	3.96	13.21	13.63	4.94	18.57	10.56	13.01	52,100	102,600	44,000	54,900	1,110,701	540,178	773,539	2,424,418
1961	9.15	3.96	13.11	13.07	4.58	17.65	10.56	12.85	51,253	94,719	45,235	54,518	1,086,762	537,434	773,967	2,398,418
1962	9.40	4.01	13.41	13.46	4.69	18.10	11.20	13.31	54,223	97,093	50,793	58,635	1,160,472	568,772	847,431	2,576,675
1963	9.22	3.98	13.20	12.70	4.49	17.19	10.58	12.69	51,801	92,368	48,201	55,023	1,071,138	441,426	790,300	2,302,864

Source: Joint Association Surveys.

TABLE A.25

HISTORY OF FEDERAL CORPORATE INCOME TAX RATE

1942-45	First 25,000		25-29
	25,000 to 50,000		53
	Over 50,000		40
46-49	First 25,000		21-25
	25,000 to 50,000		53
	Over 50,000		38
1950	Normal Tax	23	42
	Surtax over 25,000	19	
1951	Normal tax	28-3/4	50-3/4
	Surtax	22	
1952-63	Normal Tax	30	52
	Surtax	22	
1964	Normal Tax	22	50
	Surtax	28	
1965 Onwards	Normal Tax	22	48
	Surtax	26	

Source: Pechman, Joseph, Federal Tax Policy, Washington, D.C., 1966.

TABLE A. 26

THE EFFECT OF THE PERCENTAGE DEPLETION PROVISION AT DIFFERENT LEVELS OF COST/GROSS INCOME, TAX RATE 50%

(1) Gross Income	100	100	100	100	100	100	100	100	100
(2) Costs and depreciation	0	10	20	30	40	45	50	60	90
(3) Net income before depletion(1)-(2)	100	90	80	70	60	55	50	40	10
(4) Depletion allowable	27.5	27.5	27.5	27.5	27.5	27.5	25	20	25
(5) Taxable income (3)-(4)	72.5	62.5	52.5	42.5	32.5	27.5	25	20	5
(6) Tax at 50%	36.25	31.25	26.25	21.25	16.25	13.75	12.5	10	2.5
(7) After tax net income, tax return.	36.25	31.25	26.25	21.25	16.25	13.75	12.5	10	2.5
(8) Real tax rate(6)÷(3)	36.25	34.72	32.81	30.35	27.08	25.00	22.00	25.00	25.00
(9) After tax profit (7)+(4)	63.75	58.75	53.75	48.75	43.75	41.25	37.5	30	22.5
(10) Tax payable on net income alone 50% (3)	50	45	40	35	30	27.5	25	20	5
(11) Net benefit of depletion(10)-(6)	13.75	13.75	13.75	13.75	13.75	13.75	12.5	10	2.5
(12) After tax net income (4) + (7) (book value)	63.75	58.75	53.75	48.75	43.75	41.25	37.50	30.00	50.00

TABLE A. 27
ESTIMATED EXPENDITURES FOR OIL AND GAS PRODUCTION
U.S. DOMESTIC

	DRILLING COSTS Producing Oil & Gas				Other Exploration Costs						Other Development Costs		Production	
	Dry Holes	Producing Wells Total	Intangible	Tangible	Lease Acquisition	Geological & Geophysical	Land Leasing & Scouting Expenses	Lease Rentals	Other	Overhead	Equipping Leases	Overheads	Producing Costs	Overheads
	MILLION OF DOLLARS										MILLION OF DOLLARS			
1944	274	593				327				44	203	111		a
1948	426	1,058				570				79	362	213		
1953	797	1,762				987				172	483	401		
1955	744	1,826	1,337	489	651	306			263	189	426	449	1,183	
1956	909	1,959	1,432	528	561	360			287	208	477	464	1,331	
1957														
1958														
1959	821	1,830	1,281	549	554	320		193	124	183	483	442	1,450	
1960	774	1,651	1,173	476	626	277	104	193	71	197	431	424	1,390	
1961	774	1,624	1,156	467	428	280	115	189	65	219	446	457	1,455	
1962	847	1,728	1,236	492	815	299	108	197	58	213	537	478	1,535	
1963	790	1,512	1,074	438	376	300	117	193	69	200	527	470	1,581	

[a] Not Available Separately
See Under Development

Source: Joint Association Survey of
Industry Drilling Costs

1959 Thru 1963 (Section II)

1955-1956. 1953

TABLE A. 28

U.S. CRUDE AND NATURAL GAS LIQUIDS PRODUCTION BY LARGER COMPANIES

Company Crude Oil and Natural Gas Liquids	1960 Total Prod. (1,000 bpd)	1960 U.S. Prod (1,000 bpd)	1964 Total Prod. (1,000 bpd)	1964 U.S. Prod. (1,000 bpd)	1965 Total World Prod. (1,000 bpd)	1965 U.S. Prod. (1,000 bpd)	U.S. % of Company Total 1960	U.S. % of Company Total 1964	U.S. % of Company Total 1965
1. Standard Oil Co. (N.J.)	2,196	439	3,204	594	3,453	639	20	18	18
2. Gulf Oil Corp.	1,506	386	1,933	457	2,082	489	26	24	23
3. Texaco	1,234	478	1,651	583	1,838	604	39	35	33
4. Standard Oil Co. (Calif.)	983	298	1,239	398	1,422	416	30	32	29
5. Socony Mobil Oil., Inc.	823	262	1,076	347	1,211	373	32	32	31
6. Standard Oil Co. (Indiana)	319	286	405	365	456	390	90	90	85
7. Shell Oil Co.	354	354	407	407	431	431	100	100	100
8. Continental Oil Co.	210	173	323	184	380	186	82	57	49
9. Phillips Petroleum Co.	282	223	318	232	339	242	79	73	40
10. Marathon Oil Co.	111	105	235	115	290	112	95	49	39
11. Sinclair Oil Corp.	183	139	215	155	245	167	76	72	47
12. Amerada Petroleum Corp.	81	81	180	80	240	83	100	45	34
13. Union Oil Co. (Calif.)	102	98	210	115	231	131	96	55	57
14. Sun Oil Company	150	114	223	123	227	133	76	55	58
15. Atlantic Refining Co.	153	98	190	107	200	115	56	56	57
16. Cities Service Co.	130	130	150	150	153	153	100	100	100
17. Tidewater	114	114	130	121	149	140	100	93	94
18. Signal Oil & Gas Co.	84	45	98	53	103	48	54	54	46
19. Sunray D-X Oil Co.	89	82	93	83	95	84	92	89	14
20. Skelly Oil Co.	85	85	87	87	89	89	100	100	100
21. British American Oil Co.	63	26	85	24	87	23	41	28	26
22. Richfield Oil Corp	84	72	88	63	86	59	86	72	45
23. Superior Oil Co.	102	80	67	67	63	63	78	100	100
24. Tenneco	47	38	54	44	55	44	81	81	81
25. Standard Oil Co. (Ohio)	39	27	40	27	45	27	69	66	59
26. Louisiana Land & Expl. Co.	30	30	40	40	43	43	100	100	100
27. Celanese (Champion)	25	25	27	27	29	29	100	100	100
28. Ashland Oil & Refining	....	....	46	18	41	19	....	39	47
29. General American Oil Co.	24	22	24	22	22	20	92	90	91
30. Texas Eastern	16	16	19	19	19	19	100	100	100
31. Murphy Oil Corp	14	9	16	9	18	11	67	60	58
32. Union Producing (United Gas)	17	17	17	17	17	17	100	100	100
33. Kerr-McGee	41	8	14	11	15	12	70	77	76
34. Coastal States Gas Prod.	1	9	5	5	11	11	100	100	100
35. General Crude Oil Co.	9	9	9	9	9	9	100	100	100
Total 35 Companies	9,672	4,371	12,919	5,157	14,198	5,431	45	40	38
(Percent of U.S.)		55		58		60			

Source: Data from WORLD OIL Surveys and Company Annual Reports

TABLE A. 29

WELLS COMPLETED IN UNITED STATES BY LARGER COMPANIES-A FIVE YEAR COMPARISON

Company and 1965 Rank in Wells Drilled	1961 Wells	1964 Wells	1965 Wells
1. Texaco	1,455	1,308	1,196
2. Standard Oil Co. (Indiana)	848	1,131	1,062
3. Gulf Oil Corp	968	869	769
4. Humble Oil (Standard, N. J.)	1,268	1,211	751
5. Shell Oil Co.	781	1,009	678
6. Standard Oil Co. (Calif.)	803	693	674
7. Socony Mobil Oil Co.	490	439	383
8. Sun Oil Co.	341	333	367
9. Sunray D-X Oil Co.	310	312	346
10. Pennzoil Co.	355	292	330
11. Union Oil Co. of Calif.	151	225	321
12. Phillips Petroleum Co.	305	360	228
13. Continental Oil Co.	412	322	313
14. Tidewater Oil Co.	213	290	280
15. Cities Service Co.	549	344	276
16. Tenneco	111	252	264
17. Sinclair Oil Corp.	341	272	251
18. Chevron Oil Co.	212	177	212
19. Skelly Oil Co.	193	178	193
20. Midwest Oil Corp.	35	168	153
21. Atlantic Refining Co.	115	115	132
22. Coastal States Gas Prod. Co.	43	39	131
23. Marathon Oil Co.	313	297	130
24. Chanslor-Western Oil and Dev. Co.	30	84	122
25. Ashland Oil and Refining Co.	358	220	113
26. Amerada Petroleum Corp.	72	112	106
27. Union Texas (Allied Chemical)	23	136	93
28. Standard Oil Co. (Texas)	123	123	91
29. Shamrock Oil & Gas Corp.	144	99	86
30. United Gas Corp. (Union Prod.)	49	37	82
31. Monsanto	43	57	78
32. Texas Pacific Oil Co.	79	108	78
33. Chevron, Western Division	50	44	73
34. J.M. Huber Corp	94	125	73
35. Livingston Oil Co.	32	76	73
36. Standard Oil Co. (Ohio)	78	51	72
37. Union Producing	51	39	70
38. Kentucky-West Va. Gas Co.	87	65	67
39. Kewanee Oil Co.	45	54	65
40. Quaker State	82	26	63
41. Signal Oil and Gas	40	65	60
42. Cabot Corporation	27	48	52
43. Anschutz Oil Co.	....	65	51
44. Kerr-McGee	68	53	50
45. British American	78	45	49
46. Bridwell Oil Co.	69	50	45
47. Lone Star Producing	61	59	40
48. Cooperative Refinery Assoc.	20	34	39
49. Eldorado Oil & Gas	....	16	38
50. Consolidated Gas Supply	24	34	36
51. Basin Oil Company	29	18	35
52. Texas Eastern	29	17	34
53. General Crude Oil	34	16	31
54. Great Expectations	20	11	31
55. Oxford Oil Co.	43	38	31
56. An-Son Petroleum Corp.	26	28	30
57. Indiana Farm Bureau	35	35	30
58. Preston Oil Company	24	23	30
59. Southern Natural Gas	16	15	29
60. Peoples Natural Gas Co.	33	36	28
61. Alpine Oil & Royalty Co.	40	22	26
62. Colorado Oil and Gas Corp.	58	70	26
63. General American	25	10	25
64. International Oil and Gas Corp.	21	49	23
65. Aztec Oil & Gas Co.	74	28	18
Total 65 Companies	12,746	12,976	11,729
(Percent of U.S.)	27.9	29.4	29.1

Source: Data from WORLD OIL Surveys and Company Annual Reports

TABLE A.30

DRY HOLE, TOTAL WELLS AND PRODUCING WELLS FOR GAS AND CRUDE OIL FROM EXPLORATION DRILLING IN THE UNITED STATES - 1958 to 1966

Year	Number of Dry Exploratory Holes (1)	Total Exploratory Wells (2)	Total Producers (2) (1)
1966	8,705	10,313	1,608
1965	8,005	9,466	1,461
1964	8,951	10,747	1,796
1963	8,686	10,664	1,978
1962	8,803	10,785	1,982
1961	9,022	10,992	1,970
1960	9,515	11,704	2,189
1959	10,577	13,191	2,614
1958	10,632	13,199	2,567
All Years	82,896	101,061	18,165

Source:

Petroleum Facts and Figures, 1967 edition, American Petroleum Institute, New York, p. 16.

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TABLE A.31

DRY HOLE, TOTAL WELLS AND PRODUCING WELLS FOR GAS AND CRUDE OIL FROM DEVELOPMENT DRILLING IN THE UNITED STATES - 1958-1966

	PRODUCERS					DRY HOLES			Total Development Wells
Year	Oil[a] (1)	Gas[a] (2)	Total (1)+(2)=(3)	Exploratory[a] (4)	Development (3)-(4)=(5)	Total[a] (6)	Exploratory[a] (7)	Development (6)-(7)=(8)	(5)+(8)
1966	16,780	4,377	21,157	1,608	19,549	15,227	8,705	6,522	26,071
1965	18,761	4,724	23,485	1,461	22,024	16,025	8,005	8,020	30,044
1964	20,620	4,855	25,475	1,796	23,679	17,488	8,951	8,537	32,216
1963	20,288	4,751	25,039	1,978	23,061	16,347	8,686	7,661	30,722
1962	21,249	5,848	27,097	1,982	25,115	16,682	8,803	7,879	32,994
1961	21,101	5,664	26,765	1,970	24,795	17,106	9,022	8,084	32,879
1960	21,186	5,258	26,444	2,189	24,255	17,574	9,515	8,059	32,314
1959	25,800	5,029	30,829	2,614	28,215	19,265	10,577	8,688	36,903
1958	24,578	4,803	29,381	2,567	26,814	19,043	10,632	8,411	35,225
Total	-	-	-	-	217,507	-	-	-	289,368

[a] *Petroleum Facts and Figures*, 1967 edition, American Petroleum Institute, New York, p. 16.

TABLE A.32

CRUDE OIL DISCOVERIES
UNITED STATES, 1958-1966
(Thousands of Barrels)

Year	Discoveries
1966	2,963,978
1965	3,048,079
1964	2,664,767
1963	2,174,110
1962	2,180,896
1961	2,657,567
1960	2,365,328
1959	3,666,745
1958	2,608,242
Total	24,329,712

Source: Petroleum Facts and Figures, 1967 edition, American Petroleum Institute, New York, p. 57.

TABLE A.33

EXPENDITURES FOR EXPLORATION AND DEVELOPMENT
CRUDE OIL INDUSTRY
UNITED STATES - 1955-1965
(Millions of Dollars)

Year	Expenditures Exploration	Development
1955	1,944	2,252
1956	2,117	2,432
1959	2,012	2,313
1960	2,045	2,082
1961	1,851	2,070
1962	2,324	2,266
1963	1,845	2,039
1964	2,209	2,193
1965	1,971	2,133
Total	18,218	19,780

Source: Joint Association Annual Surveys.

TABLE A.34

DAYS ALLOWABLE IN TEXAS
UNITED STATES
1958 - 1962

Year	Days Allowable
1958	122
1959	123
1960	104
1961	101
1962	97
Total	547
Average 5 Years	109.4

Source: A.E. Kahn, "The Depletion Allowance and Cartelization," The American Economic Review, American Economic Association, June, 1964, p. 300.

TABLE A.35

NUMBER AND CAPACITY OF OPERATING REFINERIES AND AVERAGE CRUDE OIL RUN PER DAY UNITED STATES (1938-1967)

Year	Number of Refineries	Capacity Barrels Per Day (As of January 1)	Average Capacity Per Refinery	Average Crude Oil Runs Per Day	Average Crude Oil Runs Per Day Per Refinery
1967	260	10,412,447	40,048		
1966	267	10,171,159	38,094	9,444,364	35,372
1965	273	10,161,311	37,221	9,043,403	33,126
1964[a]	282	10,063,164	35,685	8,806,910	31,230
1963[a]	287	9,814,791	34,198	8,686,718	30,267
1962	287	9,812,248	34,189	8,409,947	29,303
1961	289	9,629,685	33,321	8,183,994	28,318
1960	290	9,543,329	32,908	8,067,032	27,817
1959	291	9,450,741	32,477	7,993,591	27,469
1958	289	8,939,907	30,934	7,605,737	26,137
1957	298	8,808,841	29,560	7,919,003	27,120
1956	294	8,380,801	28,506	7,937,448	26,816
1955	296	8,069,154	27,261	7,480,049	25,356
1954	308	7,782,103	25,267	6,957,710	23,039
1953	315	7,481,701	24,509	6,999,630	22,435
1948	352	5,825,566	16,550	5,596,583	16,269
1943	386	4,409,013	11,422	3,917,090	10,174
1938	431	3,970,196	9,212	3,191,822	7,371

[a]Revised

Source: Karg, Robert L., "A Theory of Crude Oil Prices: A Study of Vertical Integration," unpublished thesis, University of Pittsburgh, 1962, Table A-2, p. 130, and Petroleum Facts and Figures, 1967 Edition, New York, American Petroleum Institute, p. 77.

TABLE A.36

AVERAGE OPERATING COSTS OF REFINERS
UNITED STATES (1938-1967)
(CENTS PER BARREL)

Year	Average Variable Costs: Purchased Fuel	Purchased Power	Chemicals TEL and Supplies	Total Variable Costs	Average Fixed Costs: Total Labor	Maintenance Materials	Insurance and Taxes	Royalties or Research	Obsolescence and Improvements	Interest on Capital-ization	Total Fixed Costs	Total Costs
1967[a]	15.8	3.1	26.8	45.7	43.9	7.1	5.2	5.0	11.4	10.9	83.5	129.2
1966	14.5	3.3	26.8	47.6	44.0	7.0	5.2	4.8	11.3	10.8	83.1	127.7
1965	13.2	3.5	24.5	41.2	44.3	6.9	5.1	4.6	11.0	9.4	81.3	122.5
1964	12.0	3.5	23.2	38.7	44.7	6.9	5.0	4.3	12.1	9.8	82.8	121.5
1963	11.1	3.4	21.8	36.3	45.3	6.8	5.0	4.1	15.1	11.7	88.0	124.3
1962	9.2	3.4	19.8	32.4	46.0	6.6	4.6	4.3	17.3	13.5	92.3	124.7
1961	8.8	3.4	21.2	33.4	49.0	6.4	4.5	3.9	17.0	13.2	94.0	127.4
1960	6.7	3.1	22.9	32.7	50.3	6.0	4.5	3.8	17.8	12.0	94.4	127.1
1959	6.0	2.8	22.0	30.8	51.2	6.7	4.4	3.8	17.3	11.7	95.1	125.9
1958	5.7	2.7	21.4	29.8	52.7	6.7	4.2	3.5	17.9	11.3	96.3	126.1
1957	7.3	2.6	20.9	30.8	53.2	6.5	4.0	3.2	17.1	10.8	94.8	125.6
1956	6.0	2.1	20.5	28.6	50.2	6.6	3.8	3.0	16.2	10.3	90.1	118.7
1955	5.3	1.9	17.9	25.1	45.5	6.7	3.6	2.6	15.3	9.5	83.2	108.3
1954	5.3	1.7	16.8	23.8	45.7	6.8	3.3	2.5	20.2	8.8	87.3	111.1
1953	6.3	1.6	16.1	24.0	47.0	6.7	3.1	2.4	18.7	8.2	86.1	110.1
1948	8.4	1.2	10.4	20.0	42.6	5.6	2.2	1.7	11.7	6.0	69.8	89.8
1943	4.8	1.4	6.6	12.8	26.1	4.1*	1.7	1.0*	12.4	4.6	49.9	62.7
1938	5.1	0.9	3.2	10.8	17.1	3.1	1.5	0.9	10.3	3.0	35.9	46.7

[a]Estimated, data for other years are final.

Source: Petroleum Facts and Figures, 1967 Edition, New York, American Petroleum Institute, p. 117.

TABLE A.37

AVERAGE REFINERY CAPACITY, AVERAGE DAILY CRUDE RUNS
AND AVERAGE VARIABLE AND FIXED COST
UNITED STATES (1938-1967)

Year	Average Refinery Capacity[a]	Average Daily Crude Runs[a]	Average Variable Costs[b]	Average Fixed Costs[b]
	(Barrels/Day)		(Dollars/Barrel)	
1967	40,048		45.7	83.5
1966	38,094	35,372	47.6	83.1
1965	37,221	33,126	41.2	81.3
1964	35,685	31,230	38.7	82.8
1963	34,198	30,267	36.3	88.0
1962	34,189	29,303	32.4	92.3
1961	33,321	28,318	33.4	94.0
1960	32,908	27,817	32.7	94.4
1959	32,477	27,469	30.8	95.1
1958	30,934	26,137	29.8	96.3
1957	29,560	27,120	30.8	94.8
1956	28,506	26,816	28.6	90.1
1955	27,261	25,356	25.1	83.2
1954	25,267	23,039	23.8	87.3
1953	24,509	22,435	24.0	86.1
1948	16,550	16,269	20.0	69.8
1943	11,422	10,174	12.8	49.9
1938	9,212	7,371	10.8	35.9

Source: [a] Table A.3 .
[b] Table A.3 .

TABLE A.38

SIMPLE AVERAGE OF SELECTED REFINERY PRODUCTS PRICES
UNITED STATES
1958 - 1966
(per barrel)

Year	Regular-Grade (Gasoline)	Kerosene	#2 Fuel Oil (Distillate)	#6 Fuel Oil (Residual)
1966	5.3970	4.7040	4.2042	2.43
1965	5.3298	4.5528	4.0992	2.46
1964	5.0610	4.4940	4.0110	2.45
1963	5.4138	4.7166	4.2630	2.47
1962	5.5608	4.7712	4.2924	2.58
1961	5.6532	4.8804	4.3806	2.61
1960	5.6364	4.5444	4.1454	2.54
1959	5.6658	4.6074	4.3470	2.50
1958	5.7372	4.5444	4.2714	2.55

Calculated by Simple Average of Refinery Prices for all States listed in Petroleum Facts and Figures, 1967 edition, American Petroleum Institute, New York.

Regular-Grade Gasoline, p. 261
Kerosene, p. 255
#2 Fuel Oil, p. 256
#6 Fuel Oil, p. 259

TABLE A.39
WEIGHTS FOR FOUR MAJOR PRODUCTS AT REFINERY
UNITED STATES, 1958-1966

	Refinery Yield[a]					Weights				
Year	Gasoline	Kerosene	Distillate	Residual	Total	Gasoline	Kerosene	Distillate	Residual	Total
1966	45.3	6.5	22.5	7.6	81.9	.5532	.0794	.2747	.0927	1.00
1965	44.9	6.1	22.9	8.1	82.0	.5475	.0744	.2793	.0988	1.00
1964	45.0	5.2	22.8	8.2	81.2	.5542	.0640	.2808	.1010	1.00
1963	44.1	5.1	23.9	8.6	81.7	.5398	.0624	.2926	.1052	1.00
1962	44.8	5.1	23.2	9.6	82.7	.5418	.0616	.2806	.1160	1.00
1961	44.7	4.7	23.2	10.5	83.1	.5380	.0565	.2792	.1263	1.00
1960	45.2	4.6	22.4	11.2	83.4	.5420	.0551	.2686	.1343	1.00
1959	44.9	3.8	23.1	11.8	83.6	.5371	.0454	.2764	.1411	1.00
1958	45.2	3.9	22.4	12.9	84.4	.5356	.0462	.2654	.1528	1.00

[a] Petroleum Facts and Figures, 1967 edition, American Petroleum Institute, New York, p. 114.

TABLE A.40
AVERAGE REVENUE PER BARREL AT REFINERY
BASED ON FOUR MAJOR PRODUCTS
UNITED STATES, 1958-1966

	Regular-Grade Gasoline (Gasoline)			Kerosene			#2 Fuel Oil (Distillate)			#6 Fuel Oil (Residual)			Average
Year	Price	Weight	Relative Share	Price	Weight	Relative Share	Price	Weight	Relative Share	Price	Weight	Relative Share	Refinery Price
1966	5.40	.5532	2.9872	4.70	.0794	.3731	4.20	.2747	1.1537	2.43	.0927	.2252	4.7
1965	5.33	.5475	2.9181	4.55	.0744	.3385	4.10	.2793	1.1451	2.46	.0988	.2430	4.6
1964	5.06	.5542	2.8042	4.49	.0640	.2873	4.01	.2808	1.1260	2.45	.1010	.2474	4.4
1963	5.41	.5398	2.9982	4.72	.0624	.2945	4.26	.2926	1.2464	2.47	.1052	.2598	4.7
1962	5.56	.5418	3.0124	4.77	.0616	.2938	4.29	.2806	1.2037	2.58	.1160	.2992	4.8
1961	5.65	.5380	2.9912	4.88	.0565	.2757	4.38	.2797	1.2250	2.61	.1263	.3296	4.8
1960	5.64	.5420	3.0568	4.54	.0551	.2501	4.15	.2686	1.1146	2.54	.1343	.3411	4.7
1959	5.67	.5371	3.0453	4.61	.0454	.2092	4.35	.2764	1.2023	2.50	.1411	.3527	4.8
1958	5.74	.5356	3.0743	4.54	.0462	.2097	4.27	.2654	1.1322	2.55	.1528	.3896	4.8

Sources:

Price, Table A.38.
Weight, Table A.39.

FIGURE A.1

COMPARISON OF ESTIMATES OF RATE OF RETURN IN PETROLEUM DOMESTIC AND FOREIGN OPERATIONS

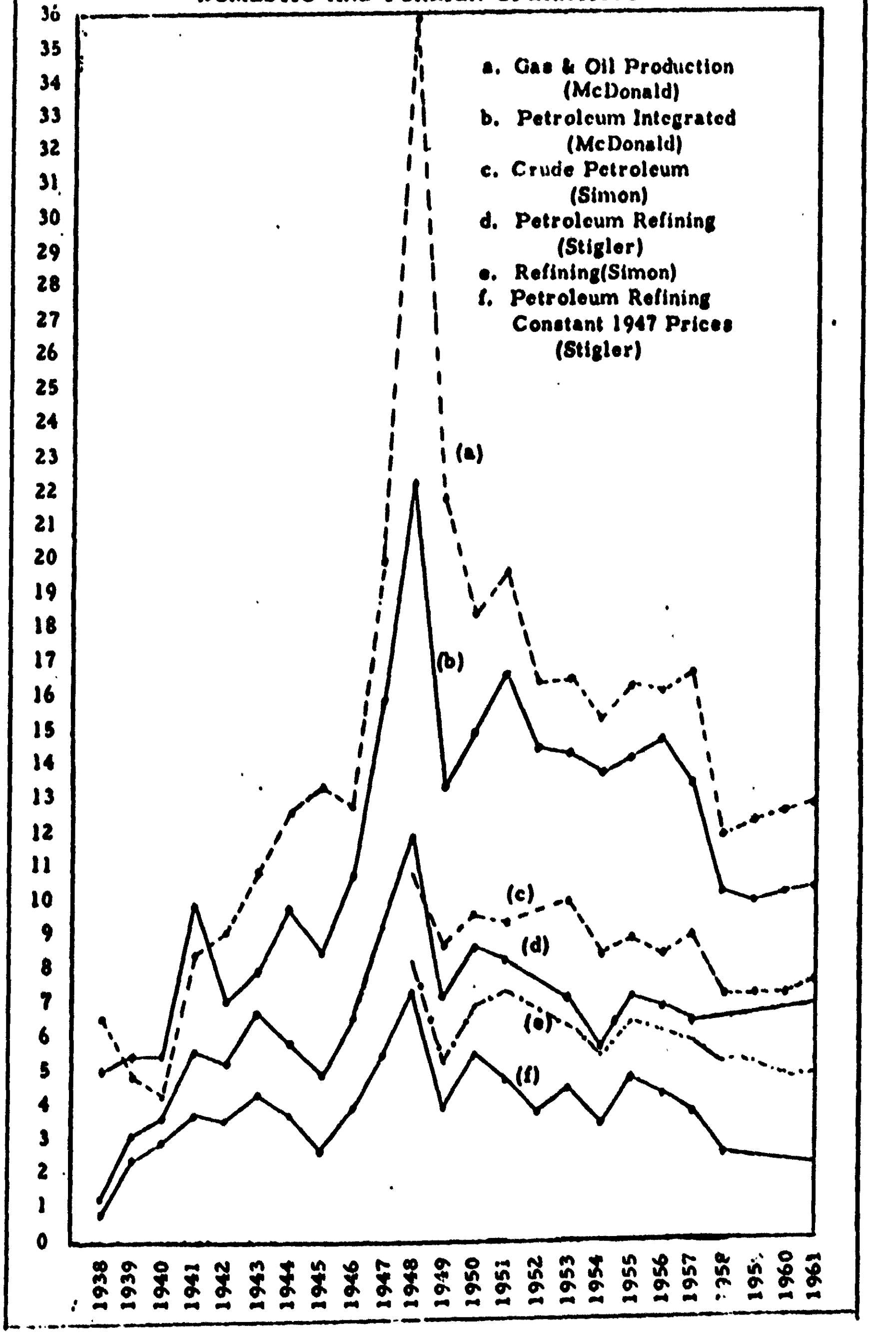
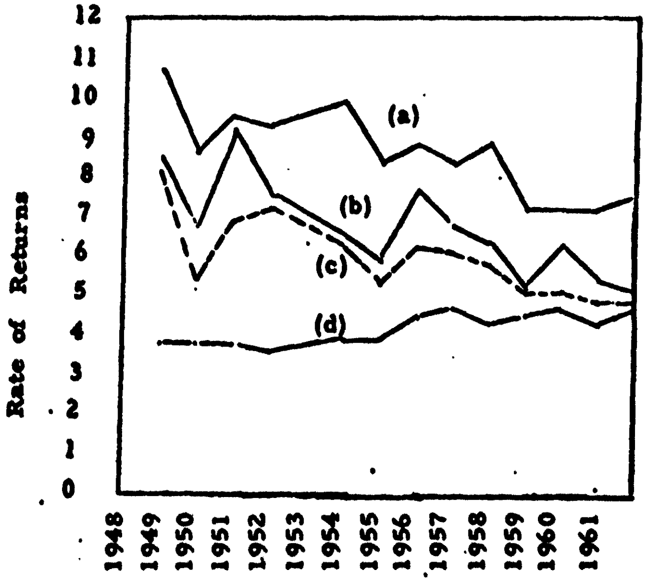


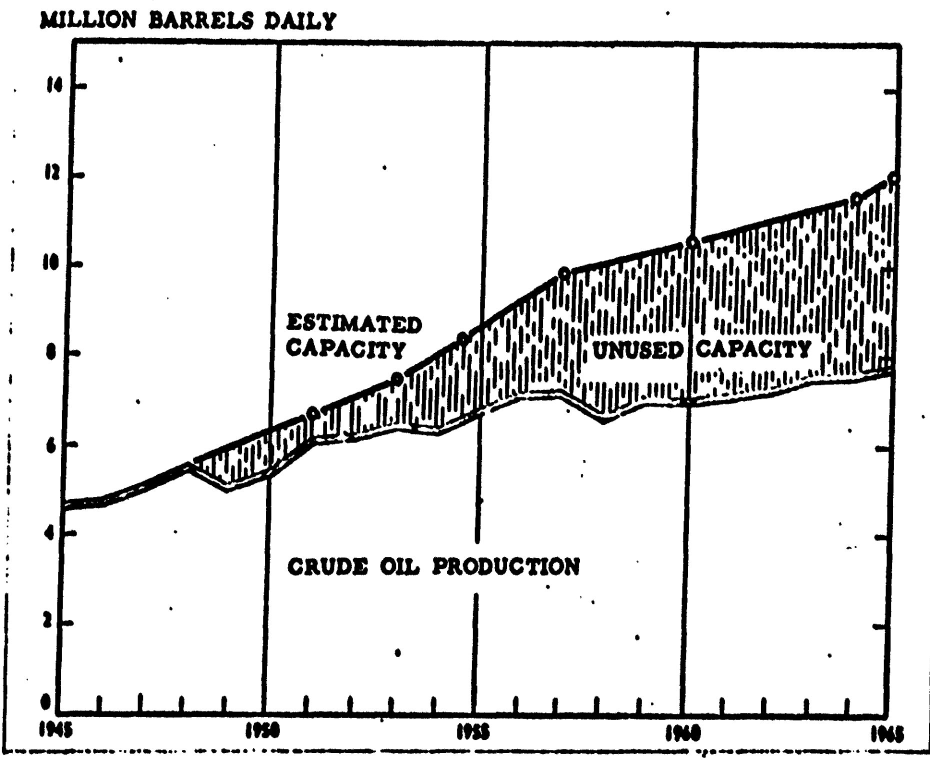
FIGURE A. 2
COMPARISON OF RATES OF RETURN IN
PETROLEUM AND OTHER INDUSTRIES
DOMESTIC AND FOREIGN PRODUCTION



a) Crude Petroleum
b) Total Manufacturing
c) Petroleum Refining
d) Electric and Gas

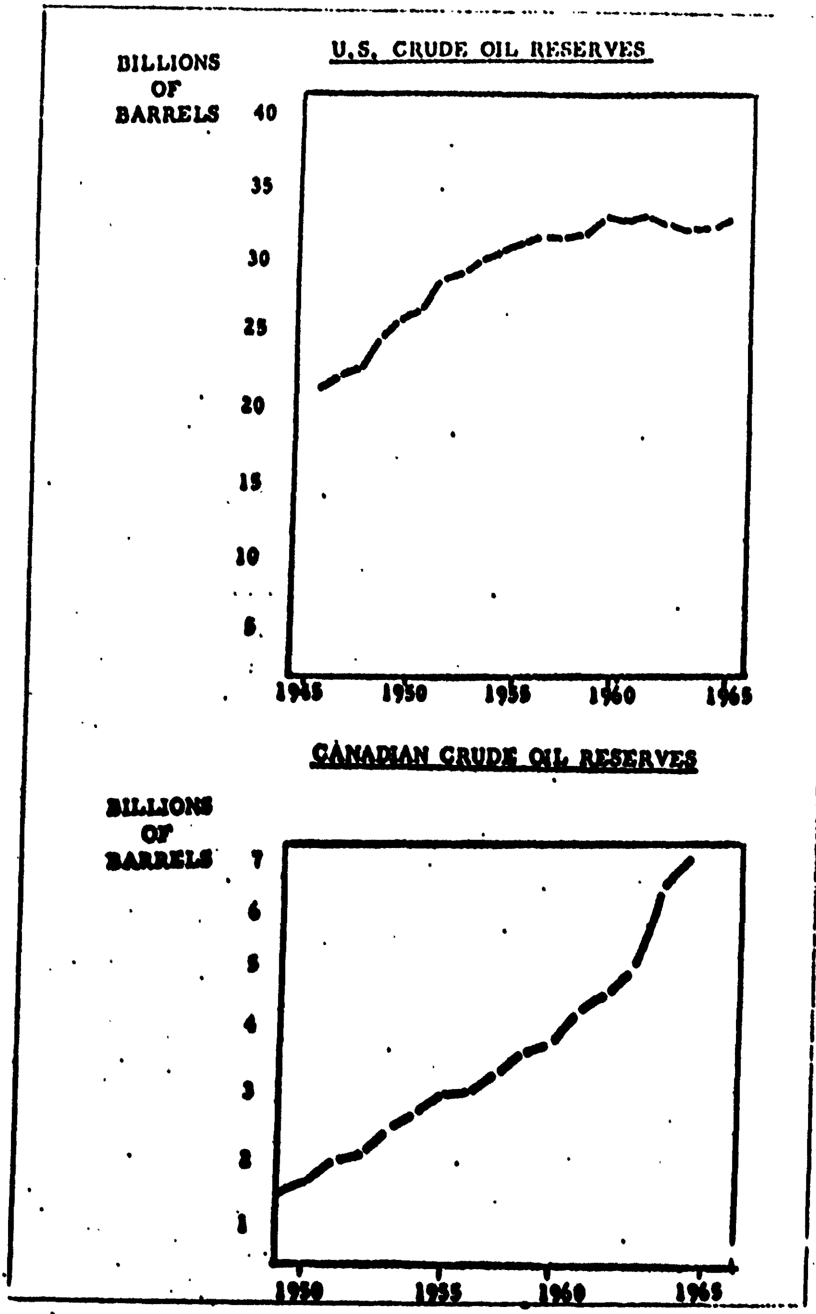
FIGURE A. 3

U.S. CRUDE OIL PRODUCTIVE CAPACITY AND PRODUCTION (1945-1965)



Source: National Petroleum Council

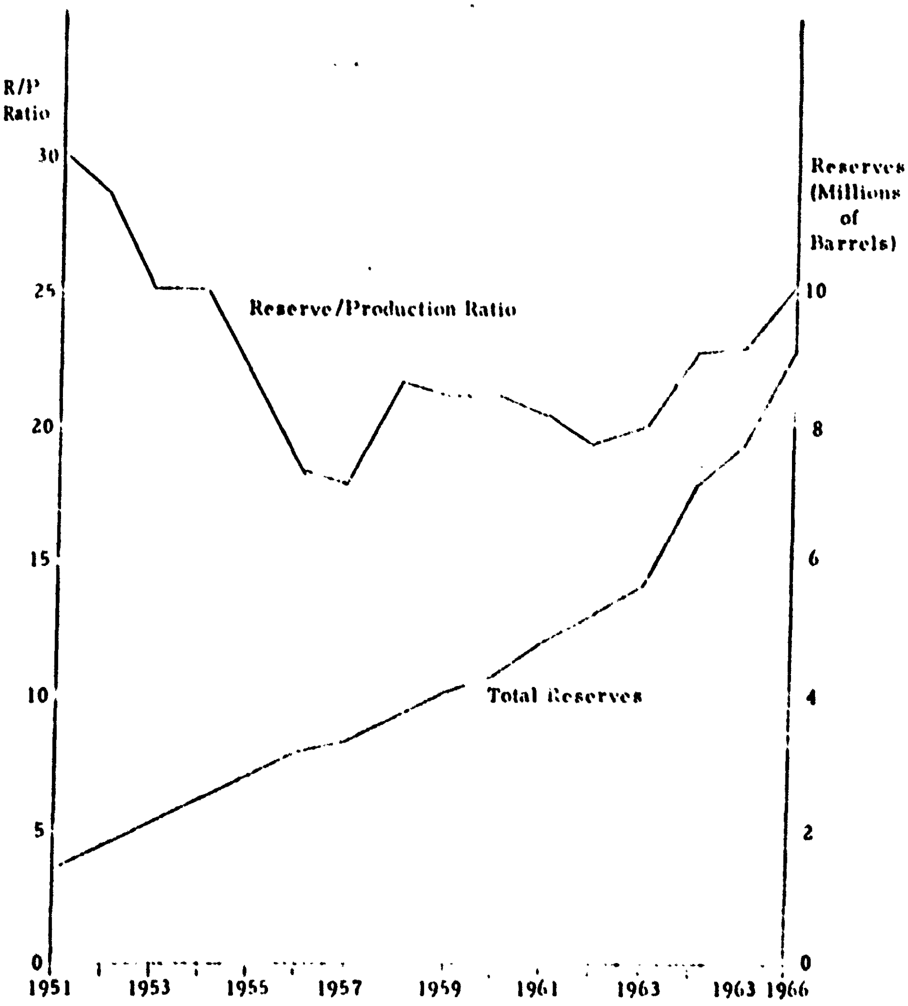
FIGURE A.4



SOURCE: Proved Reserves of Crude Oil, Natural Gas Liquids and Natural Gas Vol. 20.

FIGURE A. 5

CANADIAN LIQUID RESERVES AND RESERVE/PRODUCTION RATIO



Source: Canadian Petroleum Association.

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APPENDIX B

A. Data Collection

Throughout this study there have been substantial difficulties in obtaining data which would have broadened the analysis undertaken. There are so many missing links in the quantitative evidence available that it is difficult to know which one to rank first.

The ideal information required would relate: (1) the benefits derived from the special tax provisions to expenditures for exploration and development, and (2) the expenditures for exploration and development to reserves discovered. That is, there is a need for information by cross-matching categories about the benefits obtained from the special provisions, the expenditures undertaken for exploration and development and the amount of new reserves discovered. This would allow the sets of information to be related to each other, or linked together, so that the impact of changes in one set can be traced to effects on the other sets.

The availability of this data for the total domestic United States crude petroleum industry will be discussed first and then comments will be made on the availability of the data by size of firm.

1. Data for United States Domestic Crude Petroleum Industry .

All information concerning the amounts and types of benefits derived from the special tax provisions must be obtained from U.S. Treasury sources. The three sources used for this survey were:

Statistics of Income, Corporation Tax Returns (annually), 1960

Statistics of Income, Supplemental Report, Depletion Allowance, Washington, 1965

Depletion Study 1958-60, Office of Tax Analysis 1963 (mimeo)

The information published by the Internal Revenue Service which is the only source of tax data and a major source of other financial data have two disadvantages: there is no distinction made between foreign and domestic operations; there is a division into industries based on the major output of each firm. This is true of data on receipts, assets, depletion, etc. This means that it is impossible to measure a return to domestic oil and gas producing operations using this data, and it is also impossible to tell from published data the incidence of the depletion allowance.

The lack of domestic/foreign data is the most serious and corrected to a limited extent in the 1958-60 Treasury Depletion Study. Some, but by no means all, the relevant data was broken out by foreign and domestic operations. However, the usefulness of the study was limited because it was a sample of mainly large companies covering a known proportion of depletion claims but an unknown proportion of income expenditures and deductions. Thus, even the information that was available by foreign and domestic breakouts could not be cross-matched with other data because it was relevant only to the sample and was not adjusted to the total industry.

There is more useful quantitative data on expenditures for exploration and development than there is on the benefits of the special provisions. Data on expenditures for exploration and development are available from two sources, the annual reports published by the Joint Association Survey and the series developed by Chase Manhattan Bank. Both of these series present domestic activities only, which is extremely helpful.

The Joint Association Surveys are the most complete and detailed authoritative sources. (They contain a considerable amount of additional data on other aspects which were highly useful throughout this study.) The series is annual from 1959 to 1965 with some years available prior to this; it is a continuing survey so that future years will be available. Expenditures for exploration and development are provided separately, but there are some problems about the allocation of exploration and development expenditures to those divisions. The Chase Manhattan data is available from 1946 to 1965 but does not provide as many categories of data as the Joint Association Survey does.

Information relating to reserves discovered and other topics, such as wells drilled, is available from several different sources. Since there are a number of problems concerning the definition of reserves, the number of wells drilled is often used to derive approximate measure of new reserves discovered.

The American Petroleum Institute publishes data on new reserves discovered. The National Petroleum Council and the Interstate Oil Compact Commission also publish reserve data.

The Joint Association Survey collects and publishes information on the number and costs of wells drilled. Information on exploratory wells drilled as well as an estimate of the size of new discoveries is obtained annually by the American Association of Petroleum Geologists. In the future, this survey will also collect information on development wells.

For the total domestic petroleum industry, the most serious lack of information is a series of data on the benefits of the special provisions, which, as already indicated, is available only on combined foreign and domestic operations; what is available by domestic only is for a sample of large companies which may not be representative of the total United States domestic oil producing industry. The industrial classification which classifies firms once by major product rather than dividing the product and assets of large diversified firms into different industrial groups, makes the derivation of a series of relevant financial data almost impossible. For these reasons, the division by asset size which is available in the Statistics of Income source books, is only of marginal value, although it could be very important if the additional information were available. While the correction of the division by major product would require a complete revision of categories, the divisibility of information by foreign and domestic operations is much less of a task, since it has already been done but only for some types of data.

2. Data by Size of Firm

The information on the benefits of the special provisions is not available by size and if it were available, it would probably be based on foreign as well as domestic assets or gross receipts, besides including in the benefits the amounts derived from foreign and domestic operations. The lack of this information is surprising since it obviously is important to the Federal government. Thus, it is even more surprising that the special 1958-1960 Treasury Depletion Survey limited itself to a relatively small sample of firms, by type or size of firm.

Expenditures for exploration and development are not available in published form by size of company. The Joint Association Survey

TABLE B. 1

SUMMARY OF INFORMATION AVAILABLE BY SIZE OF FIRM

Source	Size Measure	Years	Production Domestic	Production Foreign	Drilling Costs	Number of Wells	Footage	Average Cost per foot	Depletion	Exploration & Development Expenditures
Chase Manhattan	"30 large Companies" "All Others"	1945-65	✓ ✓							✓ ✓
Census Of Mineral Industries	"200 largest" (asset size)	1963			✓	✓	✓	✓		
World Oil	35 largest domestic producers, individually	1961, 4, 5	✓	✓						
	65 largest exploring companies individually	1961, 4, 5				✓				
Treasury Depletion Survey	"Companies claiming 86% of all depletion"	1958, 1959, 1960	(✓)*	(✓)*					✓	✓

*Value of production

apparently stratifies the expenditure data they collect by size of company according to a special tabulation of receipts reported for the 1958 census, size of company being measured by producer's receipts. The Joint Association Survey does not make this material available.

If the Joint Association Survey information stratified by size of company were available, and, if the benefits from the special provisions for domestic operations could be stratified by the same categories (and there is apparently no reason why this could not be done), these two items of information would then cross-match and would provide a substantially better quantitative base upon which to build an econometric study than the data which now exists.

The importance of this point cannot be over-emphasized, for while it is known that both the benefits for the special provisions and the exploration and development effort is now uniformly distributed across the industry, this is far from knowing what the form and nature of the distribution is. These factors can only be derived or guessed at indirectly. The availability of the above two items would improve this, or any future study's ability to estimate the incidence of the benefits of the special provisions.

However, there would still be the problem of relating these benefits to exploration and development effort as measured by reserves discovered rather than expenditures; for it is, in the end, reserves which are the focus of the study. This problem of measurement of reserves is partly one of the petroleum engineers. Estimates of reserves are made at various probability levels; even at the same probability level, estimates are revised each year over a considerable period of time and reserves are only finally known through production. However, companies must make estimates and with uniform treatment of probability, data could be collected by size of company and depth of reserves.

The number of wells drilled by company size (as defined by producers' receipts) may be obtainable from the information collected by the American Association of Petroleum Geologists which will collect in the future the number of wells drilled by both exploratory and development classifications. Since their annual report indicates that the initial collection of this information is by company, possibly the information on wells could be obtained by the same category of company size as the information concerning benefits and expenditures. This should provide a satisfactory quantitative base upon which a new and more detailed econometric study could be based.

If new data collection procedures are to be designed, consideration should be given to collecting data which would allow the various proposed theories to be subjected to empirical testing.

APPENDIX C

STATISTICAL ANALYSIS OF REGRESSION EQUATIONS TESTED FOR INDUSTRY SIMULATION MODEL

1. EXPLORATION EXPENDITURES

$$\log_{10} EPEL = a_1 + a_2 \log \frac{NP(t-1)}{TEP7} + a_2 \log \frac{NRE(t-1)\ PR(t-1)}{EPEL(t-1)}$$

$a_1 = 3.43077$ $a_2 = 0.342$ $a_3 = 0.072$

Standard Error = 0.144 Standard Error = 0.095

$R^2 = 0.5847$

Standard Error = 0.0280

F Ratio = 2.816

2. EXPLORATION EXPENDITURES

$$EPEL(t) = a_1 + a_2 GIN(t)$$

$a_1 = 86,176$

$a_2 = .22507$

Standard Error = .03877

$R^2 = .8081$

Standard Error = 246,533

F Ratio = 33

3. **EXPLORATION EXPENDITURES**
$\log_{10} EPEL(t) = a_1 \log_{10} \frac{(GIN(t) - TEP(t))}{TEP(t)}$
$a_1 = -28.68414$ Standard Error = 26.19167
$R^2 = .2307$ Standard Error = 6.1852 F Ratio = 1.0

4. DEVELOPMENT EXPENDITURES

$$EPDV = a_1 + a_2\, EPEL(t) + a_3 \left(\frac{NRE(t-1)\; PR(t-1)}{EPEL(t-1)} \right)$$

$a_1 = 1349000$ $a_2 = 0.1504$ $a_3 = 1012500$

Standard Error = 0.2978   Standard Error = 505300

$R^2 = 0.7329$

Standard Error = 883000

F Ratio = 5.487

5. DEVELOPMENT EXPENDITURES

$$EPDV(t) = a_1 + a_2 GIN(t)$$

$a_1 = 77{,}262$

$a_2 = .20173$

Standard Error = .04373

$R^2 = .7268$

Standard Error = 278,046

F Ratio = 21

6. DEVELOPMENT WELLS
$\log_{10} DVW(t) = a_1 \log_{10} EPDV(t)$
$a_1 = .71822$ Standard Error = .00198
$R^2 = .9999$ Standard Error = .0376 F Ratio = 131, 352

7. **DEVELOPMENT WELLS**

$$DVW(t) = a_1 EPDV(t) + a_2 ELW(t-1) SEW(t-1)$$

$a_1 = .01025$

Standard Error = .00304

$a_2 = 5.5256$

Standard Error = .27048

$R^2 = .9951$

Standard Error = 2801

F Ratio = 706

8. DEVELOPMENT WELLS
$DVW(t) = a_1 EPDV(t)$
$a_1 = .01639$ Standard Error = .00052
$R^2 = .9921$ Standard Error = 3311 F Ratio = 1008

9. EXPLORATORY WELLS

$$\log_{10}ELW(t) = a_1\log_{10}EPEL(t)$$

$a_1 = .64620$

Standard Error = .00524

$R^2 = .9997$

Standard Error = .0739

F Ratio = 15,202

10. EXPLORATORY WELLS

$$ELW(t) = a_1 EPEL(t) + a_2 EPEL(t-1)$$

$a_1 = .00463$ | $a_2 = .00129$
Standard Error = .00371 | Standard Error = .00372

$R^2 = .9714$

Standard Error = 2674

F Ratio = 57

11. EXPLORATORY WELLS

$ELW(t) = a_1 EPEL(t)$

$a_1 = .00590$

Standard Error = .00052

$R^2 = .9702$

Standard Error = 2362

F Ratio = 130

12. GROSS INCOME

$$\log_{10} GIN(t) = a_1 + a_2 \log_{10} PR(t)PROD(t)$$

$a_1 = .07174$

$a_2 = .99321$

Standard Error = .04624

$R^2 = .9830$

Standard Error = .0270

F Ratio = 461

13. GROSS INCOME

$$GIN(t) = a_1 + a_2 PR(t) PROD(t)$$

$a_1 = 81279$

$a_2 = 1.12187$

Standard Error = .07456

$R^2 = .9659$

Standard Error = 415,316

F Ratio = 225

14. **PRODUCTION EXPENDITURES**		
$EPPR(t) = a_1 + a_2 PROD(t) + a_3 PR(t)$		
$a_1 = -6907$	$a_2 = .00114$ Standard Error = .00006	$a_3 = 2051$ Standard Error = 90
$R^2 = .9981$ Standard Error = 87 F Ratio = 1025		

15. PRODUCTION EXPENDITURES	
$EPPR(t) = a_1 + a_2 PR(t)$	
$a_1 = -6754$	$a_2 = 3036$ Standard Error = 644
$R^2 = 8165$ Standard Error = 87 F Ratio = 22	

16. PRODUCTION EXPENDITURES	
$\log_{10}EPPR(t) = a_1 + a_2\log_{10}PR(t)$	
$a_1 = 1.15485$	$a_2 = 4.6656$ Standard Error = .93257
$R^2 = .8335$ Standard Error = .0194 F Ratio = 25	

17. PRODUCTION EXPENDITURES
$\log_{10}EPPR(t) = a_1 + a_2\log_{10}PROD$
$a_1 = -13.70469$ $a_2 = 2.64733$ Standard Error = .70951
$R^2 = .7358$ Standard Error = .0244 F Ratio = 14

18. PRODUCTION EXPENDITURES

$$EPPR(t) = a_1 + a_2 PROD(t)$$

a_1 = -3029

a_2 = .001950

Standard Error = .0005

R^2 = .7453

Standard Error = 103

F Ratio = 15

The limited amount of time series data that the economic analysis revealed to be useful, prevents the full application of known statistical methods. A clear explanation of this situation is given by Herman Wald in Demand Analysis: A Study of Econometrics:

> "The refined methods of modern statistics have largely been devised for the purpose of experimental applications, and there they have won great triumphs, but it is by no means a straightforward matter to extend their application to non-experimental data. For small-sample tests, in particular, the accuracy attained will, as a rule, be illusory, since such tests require a full specification of the distribution of regression residuals and other erratic elements. For the analysis of non-experimental data we may accordingly state the conclusion, at first sight paradoxical, that when dealing with a small sample we must as a rule rest content with the rough inference drawn by the use of large-sample methods, whereas in the analysis of a large sample we may sometimes be in a position to apply more refined methods, making use of the sample to estimate the auxiliary parameters involved in the method."*

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*Wald, Herman, Demand Analysis: A Study in Econometrics, John Wiley & Sons, Inc., New York, 1953.

CUMULATIVE F DISTRIBUTION

(m degrees of freedom in the numerator;

n in the denominator: n = 3)

Significance Level	m = 1	m = 2
.900	5.54	5.46
.950	10.10	9.55
.975	17.40	16.00
.990	34.10	30.80
.995	55.60	49.80

APPENDIX D

INPUT FORMS FOR FIRM SIMULATION

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GP

INITIALIZATION - PARAMETERS
CONSAD MICRO MODEL OF CRUDE OIL MARKET OF UNITED STATES
OFFICE OF TAX ANALYSIS
U.S. TREASURY DEPARTMENT

SHEET 1
1

Identification 2 — 12 **Date** Month 13 14 Day 15 16 Year 17 — 20

Initialization Run (1: print results and stop; 11: print results and continue) 21 22

Simulation Print-Out (1: print only best solution; 11: print all simulation runs) 23 24

Simulation Year Print-Out (1: do not print each year; 11: print each year) 25 26

Number of Simulation Runs 27 28

Number of Years Per Simulation 29 30

Exploratory Wells

Drilling Costs Per Foot

Success Ratio	Dry Hole (1)	Intangible (2)	Tangible (3)	Other Exploratory Costs (Ratio to drilling costs)
Δ31 — 34	35 Δ 38	39 Δ 42	43 Δ 46	47Δ — 50

Development Wells

Drilling Costs Per Foot

Success Ratio	Dry Hole (6)	Intangible (7)	Tangible (8)
Δ51 — 54	55 Δ 58	59 Δ 62	63 Δ 66

Well Characteristics Dependent on Initial Exploration and Development Expenditures

Flush Production

Minimum Number of Days (Maximum Development) 67 — 70

Average Economic Life of Wells (Years) 71 72

Average Number of Days 73 — 76

Production Per Day (Barrels) 77 — 80

D.1

INITIALIZATION - PARAMETERS
CONSAD MICRO MODEL OF CRUDE OIL MARKET OF UNITED STATES
OFFICE OF TAX ANALYSIS
U.S. TREASURY DEPARTMENT

SHEET 2
1

Crude Oil Production
(excludes capital costs)

Operating Cost Per Day Per Well
Fixed: 2 Δ 5
Variable (per barrel): 6 Δ 9

Royalty Interests
(% of Production): 10 Δ 12

Percentage of Domestic Crude Oil
Supplied by Own Production: 13 15 Δ

Average Crude Oil Price - Dollar Per Barrel
Domestic: 16 Δ 18
Foreign: 19 Δ 21

Refinery Production
(excludes crude oil and includes capital costs)

Operating Cost Per Day Per Refinery
Fixed: 22 26 Δ
Variable (per barrel): 27 Δ 30

Crude Oil Transportation Costs
(per barrel): 31 Δ 34

Number of Refineries: 35

Refinery Demand
Crude Runs to Still Per Day
Per Refinery (barrels): 36 40 Δ

Average Refinery Price
Dollars Per Barrel: 41 Δ 43

Linear Parameters for Number of Wells and Reserves for Given Expenditures

Exploration: Δ 44 51

Development: Δ 52 59

Reserves in Barrels
Per Exploratory Well: 60 69

Average of the Ratio of Development Expenditures to Exploration Expenditures: 70 Δ 73

Interest Rate for Discounting Future Income: 74 Δ 76

Moving Average Coefficient for Exploration Expenditures: Δ 77 78

INITIALIZATION - GOVERNMENT POLICY
CONSAD MICRO MODEL OF CRUDE OIL MARKET OF UNITED STATES
OFFICE OF TAX ANALYSIS
U.S. TREASURY DEPARTMENT

SHEET 3
1

Import Quota for Crude Oil — Ratio of Crude Runs to Stills
Δ2 4

Production Restriction — Days Allowable Per Year (Between 0 and 365)
5 7

Applies to Wells with Production Per Day Greater Than Barrels Listed Below
8 Δ 12

Tax Treatment of Capital Expenditures (1: depreciated; 2: expensed; 3: included in depletion allowance)

	(1)	(2)	(3)	(4)	(5)
Exploration Category	13	14	15	16	17

	(6)	(7)	(8)
Development Category	18	19	20

Depletion Allowance Per Dollar of Income From Crude Oil Production Δ21 23

Corporation Income Tax Rate Per Dollar of Taxable Income Δ24 26

Number of Years for Depreciation 27 28

D.3

SIMULATION DATA
CONSAD MICRO MODEL OF CRUDE OIL MARKET OF UNITED STATES
OFFICE OF TAX ANALYSIS
U.S. TREASURY DEPARTMENT

SHEET 4 (1)
Simulation Year (2–3)

Prices (per barrel)

Average Refinery Yield — Change (4); Price (5–8)
Domestic Crude Oil — Change (9); Price (10–13)
Foreign Crude Oil — Change (14); Price (15–18)

Refinery Demand (per refinery)

Change (19); Barrels (20–25)

Expenditures

Change (26); Exploration (27–38); Development (39–50)

Government Policy

Import Quota for Crude Oil — Change (51); Ratio of Crude Oil Runs to Stills (52–54)

Production Restrictions — Change (55); Days Allowable Per Year (Between 0 and 365) (56–58); Applies to Wells with Production Per Day Greater Than Barrels Listed Below (59–63)

Tax Treatment of Capital Expenditures (1: depreciated; 2: expensed; 3: included in depletion allowance)

Exploration — Change (64); Category (1) 65, (2) 66, (3) 67, (4) 68, (5) 69

Development — Change (70); Category (6) 71, (7) 72, (8) 73

Depletion Allowance Per Dollar of Income from Crude Oil Production — Change (74); Ratio (75–77)

Corporation Income Tax Rate — Change (78); Rate (79–80)

(Change: blank (b̸) do not change, one (1) do change)

APPENDIX E

PROGRAM OUTPUT FOR FIRM SIMULATION

INITIALIZATION-PARAMETERS
CONSAD MICRO MODEL OF CRUDE OIL MARKET OF UNITED STATES
OFFICE OF TAX ANALYSIS
U.S. TREASURY DEPARTMENT

EXPLORATORY WELLS

	DRILLING COSTS PER FOOT			
	DRY HOLE	INTANGIBLE	TANGIBLE	OTHER EXPLORATORY COSTS
SUCCESS RATIO	(1)	(2)	(3)	(RATIO TO DRILLING COSTS)
.1797	10.64	9.32	3.80	2.000

DEVELOPMENT WELLS

	DRILLING COSTS PER FOOT		
	DRY HOLE	INTANGIBLE	TANGIBLE
SUCCESS RATIO	(6)	(7)	(8)
.7517	10.64	9.32	3.80

WELL CHARACTERISTICS DEPENDENT ON INITIAL EXPLORATION AND DEVELOPMENT EXPENDITURES FOR FLUSH PRODUCTION

MINIMUM NUMBER OF DAYS (MAXIMUM DEVELOPMENT)	AVERAGE ECONOMIC LIFE OF WELLS (YEARS)	AVERAGE NUMBER OF DAYS	PRODUCTION PER DAY (BARRELS)
30	30.	180	75.00

CRUDE OIL PRODUCTION (EXCLUDES CAPITAL COSTS)	OPERATING COST PER DAY PER WELL FIXED	VARIABLE (PER BARREL)	ROYALTY INTERESTS (PERCENT OF PRODUCTION)
	.435	.765	12.5

PERCENTAGE OF DOMESTIC CRUDE OIL SUPPLIED BY OWN PRODUCTION	AVERAGE CRUDE OIL PRICE DOLLAR PER BARREL DOMESTIC	FOREIGN
100.	2.90	1.65

REFINERY PRODUCTION EXCLUDES CRUDE OIL AND INCLUDES CAPITAL COSTS	OPERATING COST PER DAY PER REFINERY FIXED	VARIABLE (PER BARREL)	CRUDE OIL TRANSPORTATION COSTS (PER BARREL)
	26635.	.365	.300

REFINERY DEMAND

NUMBER OF REFINERIES	CRUDE RUNS TO STILL PER DAY PER REFINERY (BARRELS)	AVERAGE REFINERY PRICE DOLLARS PER BARREL
3.	60000.	4.32

LINEAR PARAMETERS FOR CALCULATING NUMBER OF WELLS AND RESERVES FOR GIVEN CAPITAL EXPENDITURES

EXPLORATION WELLS	DEVELOPMENT WELLS	RESERVES IN BARRELS PER EXPLORATORY WELL
.00000590	.00001639	2500000.

AVERAGE OF THE RATIO OF DEVELOPMENT EXPENDITURES TO EXPLORATION EXPENDITURES 1.086

INTEREST RATE FOR DISCOUNTING FUTURE INCOME 5.00
MOVING AVERAGE COEFFICIENT FOR EXPLORATION EXPENDITURE .60

E.5

CONSAD T01 10 10 1968 REPORT 2

INITIALIZATION-GOVERNMENT POLICY
CONSAD MICRO MODEL OF CRUDE OIL MARKET OF UNITED STATES
OFFICE OF TAX ANALYSIS
U.S. TREASURY DEPARTMENT

IMPORT QUOTA FOR CRUDE OIL — RATIO OF CRUDE RUN TO STILLS

.122

PRODUCTION RESTRICTION — DAYS ALLOWABLE PER YEAR (BETWEEN 0 AND 365): 120.

APPLIES TO WELLS WITH PRODUCTION PER DAY GREATER THAN BARRELS LISTED BELOW: 50.00

TAX TREATMENT OF CAPITAL EXPENDITURES (1-DEPRECIATED,2-EXPENSED,3-INCLUDED IN DEPLETION ALLOWANCE)

	EXPLORATION BY CATEGORY					DEVELOPMENT BY CATEGORY		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	2	2	2	1	3	2	2	1

DEPLETION ALLOWANCE PER DOLLAR OF INCOME FROM CRUDE OIL PRODUCTION .275

CORPORATION INCOME TAX RATE PER DOLLAR OF TAXABLE INCOME .52

NUMBER OF YEARS FOR DEPRECIATION 10

TAX CALCULATIONS FOR YEAR 6 SIMULATION RUN 0

CONSAD MICRO MODEL OF CRUDE OIL MARKET OF UNITED STATES

OFFICE OF TAX ANALYSIS

U.S. TREASURY DEPARTMENT

REVENUE				
REFINERY SALES				283824000.
CRUDE OIL SALES				0.
TOTAL SALES				283824000.
OPERATING COSTS				
REFINERY PRODUCTION			72724425.	
CRUDE OIL PRODUCTION			45616982.	
CRUDE OIL IMPORTS			13225410.	
CRUDE OIL DOMESTIC PURCHASES			20910667.	
TOTAL OPERATING COSTS				152477484.
DEPLETION ALLOWANCE				40253035.
CAPITAL EXPENDITURES				
EXPLORATION				
DRY HOLES				
DRILLING COSTS	5711517.			
OTHER EXPLORATION COSTS	11901487.			
TOTAL DRY HOLE		17613004.		
PRODUCING WELLS				
INTANGIBLE DRILLING COSTS	1095976.			
TANGIBLE DRILLING COSTS	446857.			
OTHER EXPLORATORY	0.			
TOTAL PRODUCING WELLS		1542833.		
TOTAL EXPLORATION			19155838.	
DEVELOPMENT				
DRY HOLES		4993469.		
PRODUCING WELLS				
INTANGIBLE DRILLING COSTS	13241722.			
TANGIBLE DRILLING COSTS	5398985.			
TOTAL PRODUCING WELLS		18640707.		
TOTAL DEVELOPMENT			23634176.	
TOTAL CAPITAL EXPENDITURE DEDUCTIONS				42790014.
TOTAL DEDUCTIONS				235520533.
TAXABLE INCOME				48303467.
TAX PAYMENT				25117803.

E.5

CONSAD T01 10 10 1968 REPORT 4

INCOME STATEMENT FOR YEAR 0 SIMULATION RUN 0
CONSAD MICRO MODEL OF CRUDE OIL MARKET OF UNITED STATES
OFFICE OF TAX ANALYSIS
U.S. TREASURY DEPARTMENT

REVENUE			
REFINERY SALES			283824000.
CRUDE OIL SALES			0.
TOTAL REVENUE			283824000.
OPERATING COSTS			
REFINERY OPERATING COSTS	72724425.		
CRUDE OIL OPERATING COSTS	45616982.		
CRUDE OIL IMPORTS	13225410.		
CRUDE OIL PURCHASES-DOMESTIC	20910667.		
TOTAL OPERATING COSTS		152477484.	
CAPITAL EXPENDITURES			
EXPLORATION			
DRY HOLES			
DRILLING COSTS	5711517.		
OTHER EXPLORATION COSTS	11901487.		
PRODUCING WELLS			
INTANGIBLE DRILLING COSTS	1095976.		
TANGIBLE DRILLING COSTS	446857.		
OTHER EXPLORATION COSTS	2607214.		
TOTAL EXPLORATION EXPENDITURES		21763051.	
DEVELOPMENT			
DRY HOLES (DRILLING COSTS)	4993469.		
PRODUCING WELLS			
INTANGIBLE DRILLING COSTS	13241722.		
TANGIBLE DRILLING COSTS	5398985.		
TOTAL DEVELOPMENT EXPENDITURES		23634176.	
INCOME TAXES		25117803.	
TOTAL OUTLAYS			222992515.
NET PROFITS			60831485.
DISCOUNTED NET PROFITS			60831485.
INCOME TAXES/GROSS PROFITS			.29224

CRUDE OIL RESERVES		
RESERVES AT BEGINNING OF PERIOD		685748293.
PRODUCTION OF CRUDE OIL		57684600.
SUBTOTAL		628063693.
NEW RESERVES		57684600.
RESERVES AT END OF PERIOD		685748293.
CRUDE OIL SUPPLY		
DOMESTIC PRODUCTION		
TOTAL PRODUCED	57684600.	
ROYALTY INTEREST	7210575.	
COMPANY SHARE		50474025.
NET DOMESTIC PURCHASES		7210575.
IMPORTS		8015400.
TOTAL CRUDE RUN TO STILL		65700000.

SIMULATION DATA FOR PRICES, REFINERY DEMAND, AND CAPITAL EXPENDITURES FOR RUN 4
CONSAD MICRO MODEL OF CRUDE OIL MARKET OF UNITED STATES
OFFICE OF TAX ANALYSIS
U.S. TREASURY DEPARTMENT

YEAR	PRICES REFINERY	CRUDE OIL DOMESTIC	FOREIGN	REFINERY DEMAND	CAPITAL EXPENDITURES EXPLORATION	DEVELOPMENT
0	4.32	2.90	1.65	60000.	21763051.	23634176.
1	4.32	2.90	1.65	60000.	21763072.	24104770.
2	4.32	2.90	1.65	60000.	21763072.	24586365.
3	4.32	2.90	1.65	60000.	21763072.	25078693.
4	4.32	2.90	1.65	60000.	21763072.	25580175.
5	4.32	2.90	1.65	60000.	21763072.	26091778.
6	4.32	2.90	1.65	60000.	21763072.	26613614.
7	4.32	2.90	1.65	60000.	21763072.	27145866.
8	4.32	2.90	1.65	60000.	21763072.	27688924.
9	4.32	2.90	1.65	60000.	21763072.	28242580.
10	4.32	2.90	1.65	60000.	21763072.	28807432.

[illegible] 1968 REPORT 4

SIMULATION DATA FOR GOVERNMENT POLICIES FOR RUN 4
CONSAD MICRO MODEL OF CRUDE OIL MARKET OF UNITED STATES
OFFICE OF TAX ANALYSIS
U.S. TREASURY DEPARTMENT

YEAR	IMPORT QUOTA	PRODUCTION RESTRICTIONS NO. OF DAYS	PRODUCTION RESTRICTIONS PRODUCTION	TAX TREATMENT OF CAPITAL EXPENDITURES (1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	DEPLETION ALLOWANCE	INCOME TAX RATE
0	.122	120.	50.00	2.	2.	2.	1.	3.	2.	2.	1.	.275	.52
1	.122	120.	50.00	2.	2.	2.	1.	3.	2.	2.	1.	.275	.52
2	.122	120.	50.00	2.	2.	2.	1.	3.	2.	2.	1.	.275	.52
3	.122	120.	50.00	2.	2.	2.	1.	3.	2.	2.	1.	.275	.52
4	.122	120.	50.00	2.	2.	2.	1.	3.	2.	2.	1.	.275	.52
5	.122	120.	50.00	2.	2.	2.	1.	3.	2.	2.	1.	.275	.52
6	.122	120.	50.00	2.	2.	2.	1.	3.	2.	2.	1.	.275	.52
7	.122	120.	50.00	2.	2.	2.	1.	3.	2.	2.	1.	.275	.52
8	.122	120.	50.00	2.	2.	2.	1.	3.	2.	2.	1.	.275	.52
9	.122	120.	50.00	2.	2.	2.	1.	3.	2.	2.	1.	.275	.52
10	.122	120.	50.00	2.	2.	2.	1.	3.	2.	2.	1.	.275	.52

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SELECTED VARIABLES FOR ANALYSIS OF SIMULATION RUN 4
CONSAD MICRO MODEL OF CRUDE OIL MARKET OF UNITED STATES
OFFICE OF TAX ANALYSIS
U.S. TREASURY DEPARTMENT

YEAR	RESERVES AT END OF YEAR	NET CHANGE IN RESERVES	CRUDE PRODUCTION	PROFITS	INCOME TAX PAYMENT	INCOME TAXES/ GROSS PROFITS	DISCOUNTED PROFITS
1	685748344.	52.	50474025.	60559647.	24418847.	.292	57676065.
2	685721612.	-26734.	50491467.	60322918.	24720456.	.291	54714665.
3	685697748.	-23865.	50494925.	60053143.	24494470.	.290	51676163.
4	685696914.	-834.	50474902.	59746980.	24243841.	.289	49165566.
5	685476207.	-20707.	50492191.	59521194.	24006738.	.287	46636413.
6	685462523.	-13455.	50456021.	59248695.	23744874.	.286	44212440.
7	685336545.	-126007.	50544329.	59218657.	23736697.	.285	42014665.
8	685498493.	-38062.	50507377.	58745962.	23215257.	.283	40761579.
9	685306679.	-115204.	50575402.	58568507.	22974427.	.282	37753975.
10	685207151.	-175517.	50627620.	58365610.	22717674.	.280	35831421.

DISCOUNTED VALUE OF RESERVES AT END OF SIMULATION 324045661.

VALUE OF PROFITS AND RESERVES DISCOUNTED TO TIME 0 763680533.

[redacted]

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SUMMARY OF SELECTED VARIABLES FOR SIMULATION RUNS
CONSAD MICRO MODEL OF CRUDE OIL MARKET OF UNITED STATES
OFFICE OF TAX ANALYSIS
U.S. TREASURY DEPARTMENT

RUN NUMBER	PERCENTAGE CHANGE CRUDE OIL RESERVES	CRUDE PRODUCTION (1000 OF BARRELS)	TOTAL PROFITS AND TAXES (1000 OF DOLLARS) PROFITS	TAX PAYMENTS	INCOME TAXES/ GROSS PROFITS	DISCOUNTED VALUE PROFITS (1000 OF DOLLARS)	RESERVES
4	-.03	505214.	594266.	258574.	.286	449643.	324045.

APPENDIX F

OPERATING PROCEDURES AND PROGRAM LISTING

I. Deck Set-Up for the Micro-Model

1. The FORTRAN II program deck including one subroutine,

2. Card signifying that data follows (may vary with the computer system employed for processing program),

3. Data card number 1 punched as described in Appendix H, sheet 1,

4. Data card number 2 punched as described in Appendix H, sheet 2,

5. Data card number 3 punched as described in Appendix H, sheet 3,

6. Data deck number 1 consisting of N (where N is number of years to be simulated; $1 \leq N \leq 20$) cards punched as described in Appendix H, sheet 4,

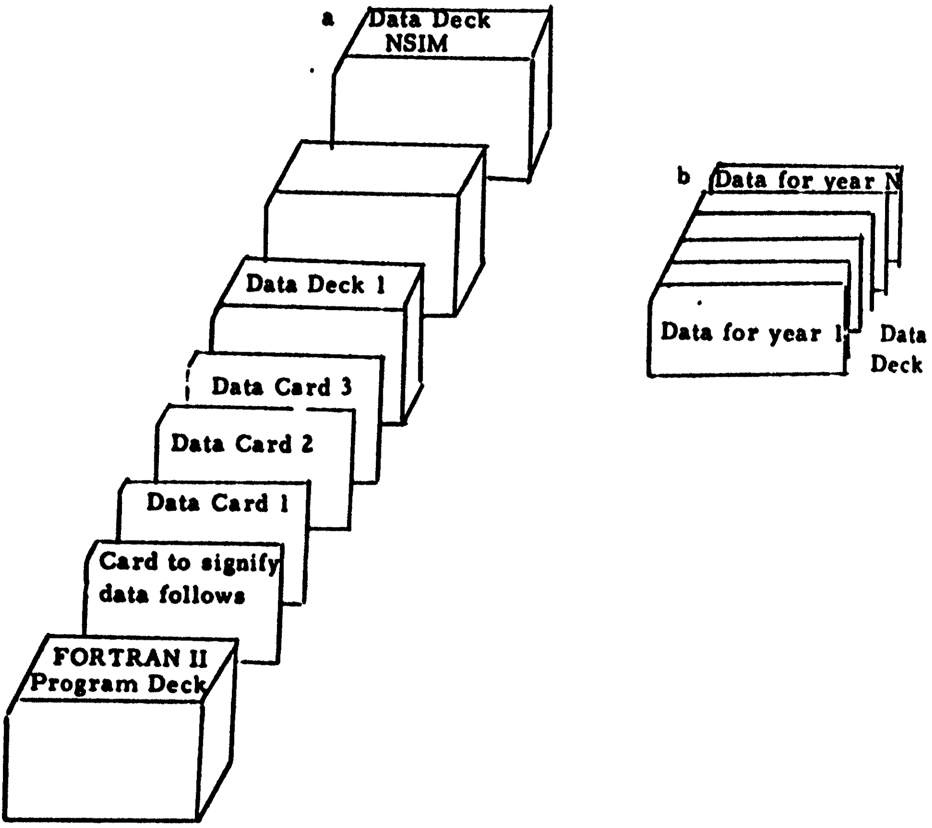
7. Data decks 2 through NSIM (where NSIM is the number of runs; $1 \leq NSIM \leq 9$) set up as data deck number 1 above,

8. The number of years to be simulated must be constant in runs 1-NSIM

FIGURE F.1

CARD SEQUENCE

CONSAD MICRO MODEL OF CRUDE OIL
MARKET OF UNITED STATES



[a] $1 \leq NSIM \leq 9$
[b] $1 \leq N \leq 20$

II. Programmed Error Messages

1. "Input card error -- card numbered Y read for card X"

   a) Cause -- one of first three data cards out of order
   b) Correction -- set up data card in correct sequence

2. "Economic Production = X is greater than maximum allowable production - Y"

   a) Cause -- input parameters for crude oil production are unrealistic
   b) Correction -- must change data on one or more of the first three data cards

3. "Input card error-card for year X read for year Y"

   a) Cause -- one or more of the cards in the data decks are out of order
   b) Correction -- arrange data cards within data decks in ascending order, e.g., year 1, year 2, . . . , year N

FORTRAN PROGRAM LISTING

CONSAD MICRO MODEL OF CRUDE OIL MARKET OF THE UNITED STATES

```
      FORTRAN
      UNIVERSAL FCOSTW,TRATE,DPRICE,ROYAL,VCOSTR,DEPL, YINT, ZINT
      UNIVERSAL NW, TSTAR, P,T, ABHE,XX,QZERO,QE,   TU,AD,QMAX,VTOT
      UNIVERSAL RESERV, PD
      UNIVERSAL BCAP, SUM
      UNIVERSAL NTAX,DBASE,NYRDEP
      DIMENSION AS(9,20)
      DIMENSION ID(4),EXDC(4),DVDC(3),NTAX(8),RC(8),Z(3),P(100,4),
     1CPCOST(8),ICHG(11),DATA(21,19),DISCR(9),DBASF(20,8),
     2EXPNS(9),S1(9,21),S2(9,20),S3(9,20),S4(9,20),V3(9),SP(100,4),
     3 SHASE(20,9),VP(9)
C     ZERO MATRICES
      DO 1023 J = 1,9
 1023 VP(J) = 0.0
      DO 501 I=1,20
      DO 501 J=1,8
      SHASE(I,J)=0.0
  501 DBASE(I,J)=0.0
      INIT = 70
C  READ INPUT DATA
      K=1
      READ 1, N, (ID(J),J=1,3),MO,JDAY,JYR,IRSW,JSIMSW,JYRSW,NSIM,NYRS,
     1FXSUCR,(EXDC(J),J=1,4),DVSUCR,(DVDC(J),J=1,3),MAXDEV,ELIFE,NAVG,
     1O7FRD
    1 FORMAT(I1,2A3,A5,2A2,A4,5I2,F4.4,3F4.2,F4.3,F4.4,3F4.2,I4,F2.0,
     1I4,F4.0)
      IF (N-K) 8,9,8
    8 PRINT 7, N,K
      GO TO 4
    7 FORMAT (33H1INPUT CARD ERROR - CARD NUMBERED,I2,14H READ FOR CARD,
     1I2)
    9 K=2
      READ 2, (N,FCOSTW,VCOSTW,ROYAL,PCTSUP,DPRICE,FPRICE,FCOSTR,VCOSTR,
     1TCOST,REF,REFDEM,RPRICE,EX,DV,R,HE,ZINT,ALPHA)
    2 FORMAT (I1,2F4.3,F3.3,3F3.2,F5.0,2F4.3,F1.0,F5.0,F3.2,2F8.8,
     1F10.0,F4.3,F3.2,F2.2)
      ZINT = ZINT * .01
      IF (N-K) 8,6,8
    6 K=3
      READ 3, N,QUOTA,AD,QMAX,(NTAX(J),J=1,8),DEPL,TRATE,NYRDEP
    3 FORMAT (I1,F3.3,F3.0,F5.2,9I1,2F3.3,I2)
      IF (N-K) 8,5,8
    4 STOP
    5 CONTINUE
C  BEGIN INITIALIZATION
C     CALCULATE CONSTANTS IN EQUATION FOR T0, A AND B
      TSTAR = NAVG
      A = MAXDEV
      B = (TSTAR - A) * HE
C     CALCULATE ECONOMIC PRODUCTION
```

```
      QE=FCOSTW/(DPRICE*(1.+DEPL*TRATE)*(1.-ROYAL)-VCOSTW)
C     CALCULATE DECLINE FACTOR
      XX=(R*EXSUCR*EX)/(EXSUCR*EX+DVSUCR*DV*HE)
      ABHE=(QZERO-QE)/(XX-QZERO*TSTAR)
      ZQE=QE
      IF (QMAX-QE) 200,200,201
  200 PRINT 202,QE,QMAX
  202 FORMAT (21H1ECONOMIC PRODUCTION=,F6.2,50H IS GREATER THAN THE MAXI
     1MUM ALLOWABLE PRODUCTION=,F6.2)
      STOP
  201 T=0.0
      P(INIT,2)=TSTAR
      P(INIT,4) = ABHE
      P(INIT,3) = T
      J=INIT-1
  216 P(J,2)=TSTAR
      P(J,4)=ABHE
      P(J,3)=T
      IF (T-TSTAR) 211,211,212
  211 T=T+AD
      GO TO 210
  212 XX=ABHE*(T-TSTAR)
      Q=QZERO/EXP(XX)
      IF (Q-QMAX) 213,211,211
  213 IF(Q-QE)210,214,214
  214 T=T+365.
  210 J = J -1
      IF (J) 215,215,216
C     CALCULATE RELATIVE COST, RC
C        EXPLORATION WELLS
  215 Z(1)=EXDC(1)*(1.-EXSUCR)
      Z(2)=EXDC(2)*EXSUCR
      Z(3)=EXDC(3)*EXSUCR
      ZT= Z(1)+Z(2)+Z(3)
      ZZ = ZT *EXDC(4)
      ZT = ZT + ZZ
      DO 100  I=1,3
  100 RC(I) = Z(I)/ZT
      ZZ = ZZ/ZT
      RC(4) = (1.-EXSUCR) * ZZ
      RC(5) = ZZ - RC(4)
C        DEVELOPMENT WELLS
      Z(1)=DVDC(1)*(1.-DVSUCR)
      Z(2)=DVDC(2)*DVSUCR
      Z(3)=DVDC(3)*DVSUCR
      ZT=Z(1)+Z(2)+Z(3)
      DO 110  I=6,8
  110 RC(I)=Z(I-5)/ZT
C     CALCULATE PHYSICAL DEMAND, PD - REFINERY COST, RCOST - REVENUE,
C        REVNUE - IMPORTS, XIMP - IMPORT COST, COSTI
      PD = REF * REFDEM * 365.
      RCOST = FCOSTR * 365. * REF * (VCOSTR + TCOST) * PD
      REVNUE = RPRICE * PD
      XIMP = PD * QUOTA
      COSTI = XIMP * FPRICE
```

```
C  CALCULATE DOMESTIC PRODUCTION, SUM AND OPERATING COST, OC
      SUM=0.0
      OC = 0.0
      K1 = INIT - 1
      DO 220  J=1,K1
      T=P(J,3)
      ABHE = P(J,4)
      XX = ABHE * (T - TSTAR)
      Q=QZERO/EXP(XX)
      IF (Q-QMAX) 221,222,222
  222 D=AD
      GO TO 224
  221 IF (Q-QE) 230,223,223
  230 QM=0.0
      D = 0.0
      GO TO 220
  223 D=365.
  224 IF (T+D-TSTAR) 225,225,226
  225 QM = QZERO * D
      C = (FCOSTW + VCOSTW * QZERO) * D
      GO TO 229
  226 IF (T-TSTAR) 227,228,228
  227 XX = ABHE * (TSTAR - T - D)
      XXX = 1. - EXP(XX)
      QM = QZERO * (TSTAR - T) + (QZERO/ABHE) * XXX
      C = (FCOSTW + VCOSTW * QZERO) * (TSTAR - T) +((FCOSTW +  VCOSTW *
     1 QZERO)/ABHE)  * XXX
      GO TO 229
  228 XX = ABHE * (TSTAR - T)
      YY = ABHE * (TSTAR - T - D)
      XXX = EXP(XX) - EXP(YY)
      QM = (QZERO/ABHE) * XXX
      C = ((FCOSTW + VCOSTW * QZERO)/ABHE) * XXX
  229 CONTINUE
C  AGE WELLS
      P(J,3) = T + D
      SUM = SUM + QM
      OC = OC + C
  220 CONTINUE
      ASUM = SUM * (1. - ROYAL)
C  CALCULATE NUMBER OF WELLS, WN
      WN = ((PD - XIMP) * PCTSUP) / SUM
      DO 240  J=1,INIT
  240 P(J,1) = WN
      SUM = SUM * WN
      OC = OC * WN
C  SPLIT DOMESTIC PRODUCTION INTO ACTUAL, ASUM AND ROYALTY, RSUM
      ASUM = ASUM * WN
      RSUM = SUM - ASUM
C  CALCULATE EXPLORATION, E AND DEVELOPMENT, H EXPENDITURES AND NEW
C       RESERVES
      E=SUM/(R*EX*EXSUCR)
      EHAT = E
      SHAT = EHAT
      XN=WN-EX*EXSUCR*E
```

```
      H=XN/(DV*DVSUCR)
      RNEW = (EX * E * EXSUCR) * R
C  CALCULATE DOMESTIC PURCHASES, DP
      DP=PO - XIMP * ASUM
C  CALCULATE COST OF DOMESTIC CRUDE OIL PURCHASES, DPCOST
      DPCOST = DP * DPRICE
      COSALE = 0.0
      IF (DPCOST) 251,252,252
  251 COSALE = -DPCOST
      DPCOST = 0.0
C  CALCULATE CAPITAL COST DEDUCTIONS
  252 CAPITL = E
      CPTOT = 0.0
      ETOT = 0.0
      DO 259  I=1,9
      IF (I-5) 261,261,262
  262 CAPITL = H
  261 EXPNS(I) = CAPITL * RC(I)
      IF (NTAX(I) - 2) 263,265,264
C  EXPENDITURES ARE DEPRECIATED
  263 CPCOST(I) = EXPNS(I)
      DO 256  J=1,NYRDEP
      SBASE(J,I)=CPCOST(I)
  256 DBASE(J,I) = CPCOST(I)
      GO TO 260
C  EXPENDITURES ARE EXPENSED
  265 CPCOST(I) = EXPNS(I)
      GO TO 260
C  EXPENDITURES ARE INCLUDED IN DEPLETION ALLOWANCE
  264 CPCOST(I) = 0.0
  260 CPTOT = CPTOT + CPCOST(I)
  259 ETOT = ETOT + EXPNS(I)
C  CALCULATE DEPLETION ALLOWANCE, DA
      DA =ASUM*DPRICE*DEPL
C  CALCULATE RESERVES
      RESERV = 0.0
      K1 = INIT - 1
      TU = LOG(QZERO/QE)/ABHE+TSTAR
      DO 270  J=1,K1
      T = S(J,3)
      XX = (TU-TSTAR)*ABHE
      YY = T-TSTAR
      IF (T - TSTAR) 271,271,272
  271 RESERV = RESERV+QZERO*(TSTAR-T)+(QZERO-(QZERO/EXP(XX)))/ABHE
      GO TO 270
  272 IF (T-TU)  1272, 1272, 270
 1272 RESERV = RESERV+(QZERO*(1./EXP(ABHE*YY))-QZERO*(1./EXP(XX))))/ABHE
  270 CONTINUE
      RESERV = RESERV * WN + RNEW
      R1 = RESERV - RNEW + SUM
      DSERVE=RESERV
      RCAP = RESERV
      DO 273  J=1,NSIM
  273 S1(J,1) = RESERV
C  CALCULATE PROFIT AND TAX
```

```
      TAX = (REVNUE - RCOST - COSTI - DPCOST - OC - CPTOT  - DA) * TRATE
      PROFIT =  REVNUE - RCOST - COSTI - DPCOST - OC - ETOT - TAX
      DISCP = PROFIT
C  PRINT RESULTS OF INITIALIZATION
      N = 0
      NS=0
      ASSIGN 902 TO NPRT1
      ASSIGN 903 TO NPRT2
      ASSIGN 904 TO NPRT3
      ASSIGN 950 TO NPRT4
      GO TO 901
  950 IF (IRSW - 1) 280,280,281
  280 STOP
  281 NS=1
C  BEGIN SIMULATION
      DO 23 I=1,INIT
      DO 23 J=1,4
   23 SP(I,J)=P(I,J)
      DATA(1,1) = RPRICE
      DATA(1,2) = DPRICE
      DATA(1,3)=FPRICE
      DATA(1,4) = REFDEM
      DATA(1,5) = E
      DATA(1,6) = H
      DATA(1,7) = QUOTA
      DATA(1,8) = AD
      DATA(1,9) = DMAX
      DO 282  I=10,17
  282 DATA(1,I) = NTAX(I-9)
      DATA(1,18) = DEPL
      DATA(1,19) = TRATE
  364 N=1
      RESERV=DSERVE
      EHAT = SHAT
      DO 22 I=1,INIT
      DO 22 J=1,4
   22 P(I,J)=SP(I,J)
      DO 24 I=1,9
      DO 24 J=1,NYRDEP
   24 DHASE(J,I)=SPHASE(J,I)
C  READ DATA FOR A YEAR
  363 N1=N+1
      READ 300, NPG,NCHK,(ICHG(I),DATA(N1,I),I=1,5),(DATA(N1,I),ICHG(I),
     1  I=6,7),(DATA(N1,I),I=8,9),ICHG(8),(DATA(N1,I),I=10,14),ICHG(9),
     2  (DATA(N1,I),I=15,17),(ICHG(I),DATA(N1,I+8),I=10,11)
  300 FORMAT (I1,I2,3(I1,F4.3),I1,F6.0,I1,2F12.0,I1,F3.3,I1,F3.0,F6.2,
     1 I1,5F1.0,I1,3F1.0,I1,F3.3,I1,F2.2)
      K=4
      NN=N+INIT
      IF (NPG - K) 301,302,301
  301 PRINT 7, NPG,K
      GO TO 4
  302 IF (NCHK - N) 303,304,303
  303 PRINT 305, NCHK,N
  305 FORMAT (33H1INPUT CARD ERROR - CARD FOR YEAR,I3,14H READ FOR YEAR,
```

```
     1(3)
      GO TO 4
  304 DO 306  I=1,11
      IF (ICHO(I)) 308,308,307
  307 GO TO (320,321,322,323,324,325,326,327,328,329,330), I
  308 GO TO (333,333,333,333,334,336,337,338,339,351,351), I
  320 RPPICF = DATA(N1,I)
      GO TO 306
  321 DPRICE = DATA(N1,I)
      GO TO 306
  322 FPRICE = DATA(N1,I)
      GO TO 306
  323 HEFD=M = DATA(N1,I)
      GO TO 306
  324 E = DATA(N1,I)
      M = DATA(N1,I+1)
      GO TO 306
  325 DUPTA = DATA(N1,I+1)
      GO TO 306
  326 AD = DATA(N1,I+1)
      QMAX = DATA(N1,9)
      GO TO 306
  327 DO 331  J=1,5
  331 NTAX(J) = DATA(N1,J+9)
      GO TO 306
  328 DO 332  J=5,9
  332 NTAX(J) = DATA(N1,J+9)
      GO TO 306
  329 PEFL = DATA(N1,18)
      GO TO 306
  330 THATE = DATA(N1,19)
      GO TO 306
  333 DATA(N1,I) = DATA(N,I)
      GO TO 306
  334 DATA(N1,I) = DATA(N,I)
      DATA(N1,I+1)=DATA(N,I+1)
      GO TO 306
  336 DATA(N1,I+1) = DATA(N,I+1)
      GO TO 306
  337 DATA(N1,I+1) = DATA(N,I+1)
      DATA(N1,9) = DATA(N,9)
      GO TO 306
  338 DO 352  J=10,14
  352 DATA(N1,J) = DATA(N,J)
      GO TO 306
  339 DO 353  J=15,17
  353 DATA(N1,J) = DATA(N,J)
      GO TO 306
  351 DATA (N1,I+8) = DATA(N,I+8)
  306 CONTINUE
C  SHIFT D-PRECIATION BASE MATRIX PRIOR TO ADDING THIS YEAR
      K1 = NYRDEP - 1
      DO 335  I=1,K1
      DO 335  J=1,9
  335 DBASE(I,J) = DBASE(I+1,J)
```

```
C  CALCULATE NUMBER OF WELLS AND NEW RESERVES
      EXN = EXSUCR * EX * E
      DVN = DVSUCR * DV * H
      RNEW = R * EXN
      EHAT = ALPHA*E+(1.0-ALPHA)*EHAT
      RHAT = R * EXSUCR*EX* EHAT
      NW = EXN + DVN
      P(NW,1) = NW
      TSTAR = A + B * EHAT/H
      P(NW,2) = TSTAR
      P(NW,3)=0.0
C CALCULATE (ALPHA + BETA*H/E)
      ABHE = (OZERO-ZOF)/(RHAT/NW-OZERO*TSTAR)
      P(NW,4) = ABHE
      CAPITL = E
      CPTOT = 0.0
      ETOT = 0.0
      DO 319  I=1,4
      IF (I-5) 311,311,312
  312 CAPITL = H
  311 EXPNS(I) = CAPITL * RC(I)
      IF (NTAX(I) - 2) 313,314,315
C  EXPENDITURES ARE DEPRECIATED
  313 DBASE(NYRDEP,I) = EXPNS(I)
      D = 0.0
      J1=NYRDEP
      DO 316  J=1,NYRDEP
      D = D + (2. * (NYRDEP + 1 - J) * DBASE(J1,I))/(NYRDEP * (NYRDEP +
     1 1))
  316 J1 = J1 - 1
      CPCOST(I) = D
      GO TO 318
C  EXPENDITURES ARE EXPENSED
  314 CPCOST(I) = EXPNS(I)
      GO TO 318
C  EXPENDITURES ARE INCLUDED IN DEPLETION ALLOWANCE
  315 CPCOST(I) = 0.0
  318 CPTOT = CPTOT + CPCOST(I)
  319 ETOT = ETOT + EXPNS(I)
C  CALCULATE IMPORTS, XIMP AND IMPORT COST, COSTI
C  CALCULATE PHYSICAL DEMAND, PD + REFINERY COST, RCOST - REVENUE,
C     REVNUE
      PD = REF * REFDEM * 365.
      RCOST = FCOSTR * 365. * REF + (VCOSTR + TCOST) * PD
      REVNUE = RPRICE * PD
      XIMP = PD * QUOTA
      ASUM = (PD - XIMP)
      COSTI = XIMP * FPRICE
C  CALCULATE ECONOMIC PRODUCTION, OE
      OE = FCOSTW/(UPRICE * (1. - DEPL * TRATE) * (1.-ROYAL) - VCOSTW)
      IF (QMAX - OE) 208,208,317
C  CALCULATE DOMESTIC PRODUCTION, SUM
C  CALCULATE OPERATING COST, OC
  317 SUM = 0.0
      OC = 0.0
```

```
      J1 = NN - 1
      DO 340 L=1,J1
      J=J1-(L-1)
      TSTAR = P(J,2)
      T = P(J,3)
      ARHE = P(J,4)
      IF (T-TSTAR)  1317, 1318, 1318
 1317 D = QZERO
      GO TO 1342
 1318 XX = ARHE * (T-TSTAR)
      D = QZERO/EXP(XX)
 1342 IF (D-DMAX) 341,342,342
  342 D = AD
      GO TO 344
  341 IF (D-DF) 350,343,343
  350 OM = 0.0
      GO TO 340
  343 D = 365.
  344 IF (T+D-TSTAR) 345,345,346
  345 OM = QZERO * D
      C = (FCOSTW + VCOSTW*QZERO) * D
      GO TO 349
  346 IF (T-TSTAR) 347,348,348
  347 XX = ARHE *      ( TSTAR - T - D)
      XXX = 1.-EXP(XX)
      OM = QZERO * (TSTAR - T) + (QZERO/ARHE) * XXX
      C = (FCOSTW + VCOSTW * QZERO) * (TSTAR - T) +((FCOSTW + VCOSTW *
     1   QZERO)/ARHE) * XXX
      GO TO 349
  348 XX = ARHE * (TSTAR - T)
      YY = ARHE * (TSTAR - T - D)
      XXX = EXP(XX) - EXP(YY)
      OM = (QZERO/ARHE) * XXX
      C = ((FCOSTW + VCOSTW * QZERO)/ARHE) * XXX
C  AGE WELLS
  349 P(J,3) = T + D
      SUM = SUM + (OM * P(J,1))
      OC = OC + (C * P(J,1))
      IF (ASUM - SUM) 602,601,349
C
C      ADJUST FOR LAST UNEQUAL COMPANY
C
  602 P(J,3) = T - D
      SUM = SUM - (OM * P(J,1))
      OC = OC - (C * P(J,1))
      GO TO 601
  340 CONTINUE
C CALCULATE ROYALTY AND ACTUAL DOMESTIC PRODUCTION
  601 RSUM = SUM * ROYAL
      ASUM = SUM - RSUM
      AS(NS,N) = ASUM
      VP(NS)   = VP(NS) + ASUM
C  CALCULATE COST OF CRUDE OIL DOMESTIC PURCHASES, DPCOST
      DP = PD - XIMP -ASUM
      DPCOST = DP * DPRICE
```

```
      COSA_F = 0.0
      IF (DPCOST) 357,358,358
  357 COSA F =-DPCOST
      DPCOST = 0.0
C  CALCULATE DEPLETION ALLOWANCE, DA
  358 DA = ASUM*OPRICE*DEPL
C  CALCULATE NEW RESERVES
      R1 = RESERV
      RESERV = RESERV + RNEW - SUM
      S1(NS,N+1) = RESERV
C  CALCULATE PROFIT AND TAX
      TAX = (REVNUE - RCOST - COSTI - DPCOST - OC - CPTOT - DA) * TRATE
      PROFIT = REVNUE - RCOST - COSTI - DPCOST - OC - FTOT - TAX
      DISCP = PROFIT/(1.+ZINT)**N
      S2(NS,N) = PROFIT
      S3(NS,N) = TAX
      S4(NS,N) = DISCP
      IF (JYRSW-1) 361,361,360
C  PRINT YEARLY RESULTS
  360 CONTINUE
C  PRINT REPORTS 3 AND 4
      ASSIGN 904 TO NPRT3
      ASSIGN 361 TO NPRT4
      GO TO 903
  361 N = N + 1
      IF (N-NYRS) 363,363,362
  362 CONTINUE
C  PRINT REPORTS 5 AND 6
      ASSIGN 906 TO NPRT5
      ASSIGN 954 TO NPRT6
      GO TO 905
  9-  CONTINUE
      CALL RSERVE
      DISCR(NS) = VTOT/(1.+ZINT)**NYRS
      V3(NS)=DISCR(NS)
      DO 366  I=1,NYRS
  366 V3(NS) = V3(NS) + S4(NS,I)
      NS = NS + 1
      IF (NS - NSIM) 364,364,365
  365 BEST = V3(1)
      NB = 1
      DO 380  J=2,NSIM
      XX = V3 (J)
      IF (XX        - BEST) 380,380,381
  381 NB = J
      BEST = V3(NB)
  380 CONTINUE
C  PRINT RESULTS OF BEST SIMULATION
C  PRINT REPORTS 7 AND 8
      J1=NB
      ASSIGN 908 TO NPRT7
      ASSIGN 951 TO NPRT8
      GO TO 907
  951 VP(J1) = VP(J1) *1000.0
      IF (JSIMSW - 1 ) 385,385,386
```

```
C  PRINT RESULTS OF ALL SIMULATIONS
C  PRINT R-PORTS 7 AND 8
  386 K1=NR-1
      K2 = NR + 1
      ASSIGN 389 TO NPRT7
      IF (K1) 387,387,390
  390 M1=1
      M2=K1
      GO TO 395
  387 IF (NSIM - NR) 388,388,392
  392 M1=K2
      M2=NSIM
  395 DO 389  J1=M1,M2
C  PRINT RESULTS OF SIMULATION J1
      GO TO 907
  389 CONTINUE
      IF (M1-K2)  1030, 388, 1800
 1800 M1 = K2
      M2 = NSIM
      GO TO 395
  388 ASSIGN 953 TO NPRT8
      J1 = 1
      GO TO 908
  953 ASSIGN 952 TO NPRT8
      DO 952  J1=2,NSIM
      GO TO 9081
  952 CONTINUE
  385 PRINT 3400
 3400 FORMAT (1H1)
      STOP
C  PRINT R-PORT NUM-R 1
  901 K = 1
      PRINT 2000, (ID(J),J=1,3),MO,JDAY,JYR,K
      PRINT 20 0
      PRINT 2020
      PRINT 2030
      PRINT 2040
      PRINT 2050
      PRINT 2060
      PRINT 2070
      PRINT 2080, RSUCN,(RDC(J),J=1,4)
      PRINT 2090
      PRINT 2100
      PRINT 2110
      PRINT 2080, AVSUCN,(AVDC(J),J=1,3)
      PRINT 2120
      PRINT 2130
      PRINT 2140
      PRINT 2150, MAXDEV,ELIFE,NAVG,IZERO
      PRINT 2160
      PRINT 2170
      X8 = RDYAL + 130.
      PRINT 2180, FCOSTN,VCOSTN,X8
      PRINT 2190
 2000 FORMAT (1H1, 4X,2A7, A5, 2(1X, A2), 1X, A4, 70X,6HREPORT,I3)
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2010 FORMAT (1H , 45X, 25HINITIALIZATION PARAMETERS)
2020 FORMAT (1H , 31X, 55HCONSAD MICRO MODEL OF CRUDE OIL MARKET OF UNI
    1TED STATES)
2030 FORMAT (1H , 49X, 22HOFFICE OF TAX ANALYSIS)
2040 FORMAT (1H , 47X, 24HU.S. TREASURY DEPARTMENT/)
2050 FORMAT (1H , 4X, 17HEXPLORATORY WELLS, 26X, 23HDRILLING COSTS PER
    1FOOT)
2060 FORMAT (1H , 45X, 28HDRY HOLE INTANGIBLE TANGIBLE, 11X, 23HOTHER E
    1XPLORATORY COSTS)
2070 FORMAT (1H , 21X, 13HSUCCESS RATIO, 14X, 3H(1), 7X, 3H(2), 7X,
    13H(3), 12X, 25H(RATIO TO DRILLING COSTS))
2080 FORMAT (1H , 24X, F6.4, 12X, 3(4X, F6.2), 20X, F6.3/)
2090 FORMAT (1H , 4X, 17HDEVELOPMENT WELLS, 25X, 23HDRILLING COSTS PER
    1FOOT)
2100 FORMAT (1H , 45X, 28HDRY HOLE INTANGIBLE TANGIBLE)
2110 FORMAT (1H , 21X, 13HSUCCESS RATIO, 14X, 3H(6), 7X, 3H(7), 7X, 3H(
    18))
2120 FORMAT (1H , 4X, 103HWELL CHARACTERISTICS DEPENDENT ON INITIAL EXP
    1LORATION AND DEVELOPMENT EXPENDITURES FOR FLUSH PRODUCTION)
2130 FORMAT (1H , 5X, 107HMINIMUM NUMBER OF DAYS     AVERAGE ECONOMIC L
    1IFE OF WELLS     AVERAGE NUMBER OF DAYS     PRODUCTION PER DAY)
2140 FORMAT (1H , 5X, 21H(MAXIMUM DEVELOPMENT), 17X,  7H(YEARS), 40X,
    1 9H(BARRELS))
2150 FORMAT (1H ,12X,I5,27X,F3.0,28X,I5,19X,F7.2/)
2160 FORMAT (1H , 6X, 20HCRUDE OIL PRODUCTION, 8X, 31HOPERATING COST PE
    1R DAY PER WELL, 8X, 18H ROYALTY INTERESTS)
2170 FORMAT (1H , 4X, 24H(EXCLUDES CAPITAL COSTS), 9X, 27HFIXED VARIABL
    1E (PER BARREL), 4X, 23H(PERCENT OF PRODUCTION))
2180 FORMAT (1H , 35X, F6.3, 9X, F6.3, 23X, F5.1/)
2190 FORMAT (1H , 34X, 32HPERCENTAGE OF DOMESTIC CRUDE OIL, 4X,
    1 23HAVERAGE CRUDE OIL PRICE)
      PRINT 2200
      PRINT 2210
      XX = PCTSUP * 100.
      PRINT 2220, XX,DPRICE,FPRICE
      PRINT 2230
      PRINT 2240
      PRINT 2250, FCOSTR,VCOSTR,TCOST
      PRINT 2260
      PRINT 2270
      PRINT 2280
      PRINT 2290, RET,RETORN,RPRICE
      PRINT 2300
      PRINT 2310
      PRINT 2320
      PRINT 2330, EX,DV,R
      PRINT 2340, RE
      XX = ZINT * 100.
      PRINT 2350, XX
      PRINT  802, ALPHA
 802 FORMAT (5X,
    1          55HMOVING AVERAGE COEFFICIENT FOR EXPLORATION EXPENDITURE
    2   , F3.2)
      GO TO NPRT1, (702)
2200 FORMAT (1H , 37X, 26HSUPPLIED BY OWN PRODUCTION, 10X, 17HDOLLAR PE
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     1R BARREL)
 2210 FORMAT (1H , 73X, 17HDOMESTIC  FOREIGN)
 2220 FORMAT (1H , 47X, F5.0, 22X, F5.2, 4X, F5.2/)
 2230 FORMAT (1H , 6X, 19HREFINERY PRODUCTION, 9X, 35HOPERATING COST PER
     1 DAY PER REFINERY, 5X, 30HCRUDE OIL TRANSPORTATION COSTS)
 2240 FORMAT (1H , 4X, 23H EXCLUDES CRUDE OIL AND, 11X, 5HFIXED, 5X,
     1 21HVARIABLE (PER BARREL), 14X, 12H(PER BARREL),)
 2250 FORMAT(1H , 4X, 23HINCLUDES CAPITAL COSTS , 18X, F7.0, 18X, F6.3,
     1 25X, F6.3/)
 2260 FORMAT (1H , 65X, 19HREFINERY DEMAND)
 2270 FORMAT (1H , 34X, 28HNUMBER OF REFINERIES, 5X, 27HCRUDE RUNS TO ST
     1ILL PER DAY, 5X, 22HAVERAGE REFINERY PRICE)
 2280 FORMAT (1H , 62X, 22HPER REFINERY (BARRELS),  9X, 18HDOLLARS PER B
     1ARREL)
 2290 FORMAT (1H , 43X,F7.0,24X, F7.0, 23X, F5.2/)
 2300 FORMAT (1H , 4X, 93HLINEAR PARAMETERS FOR CALCULATING NUMBER OF WE
     1LLS AND RESERVES FOR GIVEN CAPITAL EXPENDITURES)
 2310 FORMAT (1H , 23X, 17HEXPLORATION WELLS, 8X, 17HDEVELOPMENT WELLS,
     1 8X, 19HRESERVES IN BARRELS)
 2320 FORMAT (1H , 73X, 20HPER EXPLORATORY WELL)
 2330 FORMAT (1H ,32X,F10.8,15X,F10.8,16X,F11.8/)
 2340 FORMAT (1H , 4X, 76HAVERAGE OF THE RATIO OF DEVELOPMENT EXPENDITUR
     1ES TO EXPLORATION EXPENDITURES, 3X, F6.3/)
 2350 FORMAT (1H , 4X, 43HINTEREST RATE FOR DISCOUNTING FUTURE INCOME,
     1 2X, F5.2)
C  PRINT REPORT NUMBER 2
  902 K = 2
      PRINT 2000, (ID(J),J=1,3),MO,JDAY,JYR,K
      PRINT 2360
      PRINT 2020
      PRINT 2030
      PRINT 2040
      PRINT 2370
      PRINT 2380, QUOTA
      PRINT 2390
      PRINT 2400
      PRINT 2410, ID,DMAX
      PRINT 2420
      PRINT 2430
      PRINT 2440
      PRINT 2450, (NTAX(J),J=1,8)
      PRINT 2460, DEPL
      PRINT 2470, TRATE
      PRINT 2480, XYDUEP
      GO TO NPRT2, (903)
 2360 FORMAT (1H , 43X, 32HINITIAL STATION-GOVERNMENT POLICY)
 2370 FORMAT (1H , 4X, 26HIMPORT QUOTA FOR CRUDE OIL, 8X, 28HRATIO OF CR
     1UDE RUN TO STILLS)
 2380 FORMAT (1H , 51X, F5.3/)
 2390 FORMAT (1H , 4X, 22HPRODUCTION RESTRICTION, 13X, 23HDAYS ALLOWABLE
     1 PER YEAR, 7X, 40HAPPLIES TO WELLS WITH PRODUCTION PER DAY)
 2400 FORMAT (1H , 41X, 19H(BETWEEN 0 AND 365), 12X, 33HGREATER THAN BAR
     1RELS LISTED BELOW)
 2410 FORMAT (1H , 49X,F4.0,33X, F7.2//)
 2420 FORMAT (1H , 4X, 98HTAX TREATMENT OF CAPITAL EXPENDITURES (1-DEDUX
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     1CIATED,2-EXPENSED,3-INCLUDED IN DEPLETION ALLOWANCE) )
 2430 FORMAT (1H , 39X, 23HEXPLORATION BY CATEGORY, 7X, 23HDEVELOPMENT B
     1Y CATEGORY)
 2440 FORMAT (1H , 41X, 19H(1) (2) (3) (4) (5), 15X, 11H(6) (7) (8))
 2450 FORMAT (1H , 39X, 5(2X, I2), 15X, I2,2X,I2,2X,I2,/)
 2460 FORMAT (1H , 4X, 64HDEPLETION ALLOWANCE PER DOLLAR OF INCOME FROM
     1CRUDE OIL PRODUCTION, 4X, F5.3/)
 2470 FORMAT (1H , 4X, 56HCORPORATION INCOME TAX RATE PER DOLLAR OF TAXA
     1BLE INCOME, 17X, F4.2/)
 2480 FORMAT (1H , 4X, 32HNUMBER OF YEARS FOR DEPRECIATION, 3X, I3)
C PRINT REPORT NUMBER 3
  903 K = 1
      PRINT 2000, (ID(J),J=1,3),ND,JDAY,JYR,K
      PRINT 2490, N,NS
      PRINT 2020
      PRINT 2030
      PRINT 2040
      PRINT 2500
      PRINT 2510, REVNUE
      PRINT 2520, COSALE
      TOT1 = REVNUE + COSALE
      PRINT 2530, TOT1
      PRINT 2540
      PRINT 2550, RCOST
      PRINT 2560, DC
      PRINT 2570, COST1
      PRINT 2580, DPCOST
      X1 = RCOST + DC + COST1 + DPCOST
      PRINT 2590, X1
      PRINT 2600, DA
      PRINT 2610
      PRINT 2620, CPCOST(1)
      PRINT 2630, CPCOST(4)
      XX = CPCOST(1) + CPCOST(4)
      PRINT 2640, XX
      PRINT 2650
      PRINT 2660, CPCOST(2)
      PRINT 2670, CPCOST(3)
      PRINT 2680, CPCOST(5)
      XXY = CPCOST(2) + CPCOST(3) + CPCOST(5)
      YY = XX + XXY
      PRINT 2690, XXY
      PRINT 2691, YY
      PRINT 2700, CPCOST(6)
      PRINT 2710, CPCOST(7)
      PRINT 2720, CPCOST(8)
      XY = CPCOST(7) + CPCOST(8)
      PRINT 2730, XY
      YX = XY + CPCOST(6)
      PRINT 2740, YX
      PRINT 2750, CPTOT
      TOT2 = X1 + DA + CPTOT
      PRINT 2760, TOT2
      TAXINC = TOT1 - TOT2
      PRINT 2770, TAXINC
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      PRINT 2780, TAX
      GO TO NPRT3, (904)
 2490 FORMAT (1H , 34X, 25HTAX CALCULATIONS FOR YEAR, I3, 1X, 14HSIMULAT
     1ION RUN, I3)
 2500 FORMAT (1H , 14X, 7HREVENUE)
 2510 FORMAT (1H , 19X, 14HREFINERY SALES, 51X, F11.0)
 2520 FORMAT (1H , 19X, 15HCRUDE OIL SALES, 50X, F11.0)
 2530 FORMAT (1H , 24X, 11HTOTAL SALES, 54X, F11.0)
 2540 FORMAT (1H , 14X, 15HOPERATING COSTS)
 2550 FORMAT (1H , 19X, 19HREFINERY PRODUCTION, 41X, F11.0)
 2560 FORMAT (1H , 19X, 20HCRUDE OIL PRODUCTION, 40X, F11.0)
 2570 FORMAT (1H , 19X, 17HCRUDE OIL IMPORTS, 43X, F11.0)
 2580 FORMAT (1H , 19X, 29HCRUDE OIL DOMESTIC PURCHASES, 32X, F11.0)
 2590 FORMAT (1H , 24X, 21HTOTAL OPERATING COSTS, 39X, F11.0/)
 2600 FORMAT (1H , 14X, 19HDEPLETION ALLOWANCE, 51X, F11.0/)
 2610 FORMAT (1H , 14X, 20HCAPITAL EXPENDITURES/ 20X, 11HEXPLORATION/
     1 25X, 9HDRY HOLES)
 2620 FORMAT (1H , 29X, 14HDRILLING COSTS, 26X, F11.0)
 2630 FORMAT (1H , 29X, 23HOTHER EXPLORATION COSTS, 17X, F11.0)
 2640 FORMAT (1H , 34X, 14HTOTAL DRY HOLE, 26X, F11.0)
 2650 FORMAT (1H , 24X, 15HPRODUCING WELLS)
 2660 FORMAT (1H , 29X, 25HINTANGIBLE DRILLING COSTS, 15X, F11.0)
 2670 FORMAT (1H , 29X, 23HTANGIBLE DRILLING COSTS, 17X, F11.0)
 2680 FORMAT (1H , 29X, 17HOTHER EXPLORATORY, 23X, F11.0)
 2690 FORMAT (1H , 34X, 21HTOTAL PRODUCING WELLS, 19X, F11.0)
 2691 FORMAT (1H ,24X,17HTOTAL EXPLORATION,38X,F11.0)
 2700 FORMAT (1H , 19X, 11HDEVELOPMENT/ 25X, 9HDRY HOLES, 41X, F11.0)
 2710 FORMAT (1H , 25X, 15HPRODUCING WELLS/ 30X, 25HINTANGIBLE DRILLING
     1COSTS, 15X, F11.0)
 2720 FORMAT (1H , 29X, 23HTANGIBLE DRILLING COSTS, 17X, F11.0)
 2730 FORMAT (1H ,34X,21HTOTAL PRODUCING WELLS,19X,F11.0)
 2740 FORMAT (1H , 24X, 17HTOTAL DEVELOPMENT, 38X, F11.0)
 2750 FORMAT (1H , 29X, 36HTOTAL CAPITAL EXPENDITURE DEDUCTIONS, 2?X,
     1F11.0/)
 2760 FORMAT (1H , 19X, 16HTOTAL DEDUCTIONS, 54X, F11.0/)
 2770 FORMAT (1H , 54X, 14HTAXABLE INCOME, 21X, F11.0)
 2780 FORMAT (1H , 54X, 12HTAX PAYMENT, 23X, F11.0)
C     PRINT REPORT NUMBER 4
  904 A = A
      PRINT 2006, (ID(J),J=1,3),MO,JDAY,JYR,K
      PRINT 2790  ,N,NS
      PRINT 2020
      PRINT 2030
      PRINT 2040
      PRINT 2800, REVNUE
      PRINT 2810, COSALE
      PRINT 2820, TOT1
      PRINT 2830, RCOST
      PRINT 2840, OC
      PRINT 2850, COSTT
      PRINT 2860, OPCOST
      PRINT 2870, X1
      PRINT 2880
      PRINT 2890, EXPNS(1)
 2790 FORMAT (1H , 35X, 29HINCOME STATEMENT FOR YEAR, I3, 1X, 14HSIMULAT
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     1ION RUN, I3)
 2500 FORMAT (1H , 19X, 7HREVENUE,/ 25X, 14HREFINERY SALES, 46X, F11.0)
 2510 FORMAT (1H , 24X, 15HCRUDE OIL SALES, 45X, F11.0)
 2520 FORMAT (1H , 29X, 13HTOTAL REVENUE, 47X, F11.0)
 2530 FORMAT (1H , 19X, 15HOPERATING COSTS/ 25X, 24HREFINERY OPERATING C
     1OSTS, 26X, F11.0)
 2540 FORMAT (1H , 24X, 25HCRUDE OIL OPERATING COSTS, 25X, F11.0)
 2550 FORMAT (1H , 24X, 17HCRUDE OIL IMPORTS, 33X, F11.0)
 2560 FORMAT (1H , 24X, 28HCRUDE OIL PURCHASES-DOMESTIC, 22X, F11.0)
 2570 FORMAT (1H , 29X, 21HTOTAL OPERATING COSTS, 29X, F11.0)
 2580 FORMAT (1H , 19X, 20HCAPITAL EXPENDITURES/ 25X, 11HEXPLORATION/
     1 30X, 9HDRY HOLES)
 2590 FORMAT (1H , 34X, 14HDRILLING COSTS, 26X, F11.0)
      PRINT 2900, EXPNS(4)
      PRINT 2910, EXPNS(2)
      PRINT 2920, EXPNS(3)
      PRINT 2930, EXPNS(5)
      XX = 0.0
      DO 400  I=1,5
  400 XX = XX + EXPNS(I)
      PRINT 2931, XX
      PRINT 2940, EXPNS(6)
      PRINT 2910, EXPNS(7)
      PRINT 2920, EXPNS(8)
      YY = 0.0
      DO 401  I=5,8
  401 YY = YY + EXPNS(I)
      PRINT 2950, YY
      PRINT 2960, TAX
      TOT2 = X1 + ETOT + TAX
      PRINT 2970, TOT2
      PRINT 2980, PROFIT
      RATIO = TAX / (PROFIT + TAX)
      PRINT 2990, DISCP
      PRINT 3000, RATIO
      PRINT 3010, R1
      PRINT 3020, SUM
      XX = R1 - SUM
      PRINT 3030, XX
      PRINT 3040, RNEW
      PRINT 3050, RESERV
      PRINT 3060, SUM
      PRINT 3070, RSUM
      PRINT 3080, ASUM
      PRINT 3090, OP
      PRINT 3100, XIMP
      PRINT 3110, PD
      GO TO NPRT4, (250,361)
 2900 FORMAT (1H , 34X, 23HOTHER EXPLORATION COSTS, 17X, F11.0)
 2910 FORMAT (1H , 29X, 15HPRODUCING WELLS/ 35X, 25HINTANGIBLE DRILLING
     1COSTS, 15X, F11.0)
 2920 FORMAT (1H , 34X, 23HTANGIBLE DRILLING COSTS, 17X, F11.0)
 2930 FORMAT (1H , 34X, 23HOTHER EXPLORATION COSTS, 17X, F11.0)
 2931 FORMAT (1H ,29X,30HTOTAL EXPLORATION EXPENDITURES,20X,F11.0/)
 2940 FORMAT (1H , 24X, 11HDEVELOPMENT/ 30X, 25HDRY HOLES (DRILLING COST
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     15), 19X, F11.0)
 2950 FORMAT (1H , 29X, 30HTOTAL DEVELOPMENT EXPENDITURES, 20X, F11.0/)
 2960 FORMAT (1H , 19X, 12HINCOME TAXES, 49X, F11.0/)
 2970 FORMAT (1H , 19X, 13HTOTAL OUTLAYS, 52X, F11.0/)
 2980 FORMAT (1H , 54X, 11HNET PROFITS, 10X, F11.0)
 2990 FORMAT (1H , 54X, 22HDISCOUNTED NET PROFITS, 8X, F11.0)
 3000 FORMAT (1H ,54X,26HINCOME TAXES/GROSS PROFITS,9X,F11.5/)
 3010 FORMAT (1H , 19X, 18HCRUDE OIL RESERVES/ 25X, 31HRESERVES AT BEGIN
     1NING OF PERIOD, 5X, F15.0)
 3020 FORMAT (1H , 24X, 23HPRODUCTION OF CRUDE OIL, 13X, F15.0)
 3030 FORMAT (1H , 29X, 8HSUBTOTAL, 23X, F15.0)
 3040 FORMAT (1H , 24X, 12HNEW RESERVES, 24X, F15.0)
 3050 FORMAT (1H , 29X, 25HRESERVES AT END OF PERIOD, 6X, F15.0/)
 3060 FORMAT (1H , 19X, 16HCRUDE OIL SUPPLY / 25X, 19HDOMESTIC PRODUCTIO
     1N / 51X, 14HTOTAL PRODUCED, 12X, F15.0)
 3070 FORMAT (1H , 30X, 14HROYALTY INTEREST, 10X, F15.0)
 3080 FORMAT (1H , 35X, 13HCOMPANY SHARE, 13X, F15.0)
 3090 FORMAT (1H , 24X, 22HNET DOMESTIC PURCHASES, 15X, F15.0)
 3100 FORMAT (1H , 24X, 7HIMPORTS, 30X, F15.0)
 3110 FORMAT (1H , 29X, 24HTOTAL CRUDE RUN TO STILL, 8X, F15.0)
C  PRINT REPORT NUMBER 5
  905 K=5
      PRINT 2000, (ID(J),J=1,3),ND,JDAY,JYR,K
      PRINT 3120, NS
      PRINT 2020
      PRINT 2030
      PRINT 2040
      PRINT 3130
      K3=NYRS + 1
      DO 500  K1=1,K3
      K2=K1-1
  500 PRINT 3140, K2,(DATA(K1,I),I=1,6)
      GO TO NPRTS, (906)
 3120 FORMAT (1H , 20X, 75HSIMULATION DATA FOR PRICES,REFINERY DEMAND,AN
     1D CAPITAL EXPENDITURES FOR RUN, 1X, I2)
 3130 FORMAT (1H , 37X, 6HPRICES/ 19X, 4HYEAR, 10X, 9HCRUDE OIL, 7X,
     1 15HREFINERY DEMAND, 5X, 20HCAPITAL EXPENDITURES / 26X, 20HREFINER
     2Y    DOMESTIC    FOREIGN, 21X, 25HEXPLORATION   DEVELOPMENT)
 3140 FORMAT (1H , 19X, I2, 6X, F4.2, 7X, F4.2, 6X, F4.2, 9X, F7.0, 7X,
     1 F11.0, 2X, F12.0/)
C  PRINT REPORT NUMBER 6
  906 K=6
      PRINT 2000, (ID(J),J=1,3),ND,JDAY,JYR,K
      PRINT 3150, NS
      PRINT 2020
      PRINT 2030
      PRINT 2040
      PRINT 3160
      PRINT 3170
      K3=NYRS +1
      DO 600  K1=1,K3
      K2=K1-1
  600 PRINT 3180, K2,(DATA(K1,I),I=7,19)
      GO TO NPRTS, (954)
 3150 FORMAT (1H , 35X, 47HSIMULATION DATA FOR GOVERNMENT POLICIES FOR R
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     1UN, 13)
 3160 FORMAT (1H , 15X, 94HIMPORT   PRODUCTION RESTRICTIONS   TAX TREATM
     1ENT OF CAPITAL EXPENDITURES   DEPLETION    INCOME)
 3170 FORMAT (1H , 8X, 103HYEAR   QUOTA    NO.OF DAYS   PRODUCTION
     1(1) (2) (3) (4) (5) (6) (7) (8)      ALLOWANCE   TAX RATE)
 3180 FORMAT (1H , 8X, I3, 5X, F4.1, 7X,F4.0,8X, F6.2, 7X, 8(2X,F2.0),9X
     1, F4.3, 8X, F3.2/)
C  PRINT REPORT NUMBER 7
  907 K=7
      PRINT 2000, (ID(J),J=1,3),MO,JDAY,JYR,K
      PRINT 3190, J1
      PRINT 2020
      PRINT 2030
      PRINT 2040
      PRINT 3200
      PRINT 3210
      DO 700  I=1,NYRS
      J=I+1
      XX = S1(J1,J) - S1(J1,I)
      YY=S3(J1,I)/(S2(J1,I)+S3(J1,I))
      ZZ = AS(J1,I)
  700 PRINT 3220, I,S1(J1,J),XX,ZZ   ,S2(J1,I),S3(J1,I),YY,S4(J1,I)
      PRINT 3230, DISCR(J1)
      PRINT 3240, V3(J1)
      PRINT 3250
      GO TO NPRT7, (908,399)
 3190 FORMAT (1H , 33X, 49HSELECTED VARIABLES FOR ANALYSIS OF SIMULATION
     1 RUN, 1X, I2)
 3200 FORMAT (1X,
     1      110H            RESERVES      NET CHANGE       CRUDE
     2                 INCOME TAX    INCOME TAXES/  DISCOUNTED       )
 3210 FORMAT (1X,
     1      110HYEAR  AT END OF YEAR   IN RESERVES    PRODUCTION
     2PROFITS          PAYMENT      GROSS PROFITS    PROFITS       )
 3220 FORMAT(1H ,I2,4X,F12.0,5X,F10.0,3X,F12.0,3X,F12.0,3X,F12.0,7X,
     1F5.3,6X,F12.0)
 3230 FORMAT (1H , 61X, 29HDISCOUNTED VALUE OF RESERVES, 5X, F14.0)
 3240 FORMAT (1H , 67X, 20HAT END OF SIMULATION/ 65X, 20HVALUE OF PROFIT
     1S AND RESERVES, 4X, F15.0)
 3250 FORMAT (1H , 73X, 20HDISCOUNTED TO TIME 0)
C  PRINT REPORT NUMBER 8
  908 K=8
      PRINT 2000, (ID(J),J=1,3),MO,JDAY,JYR,K
      PRINT 3260
      PRINT 2020
      PRINT 2030
      PRINT 2040
      PRINT 3270
      PRINT 3280
      PRINT 3290
 9081 V1=0.0
      V2=0.0
      DO 800  I=1,NYRS
      V1 = V1 + S2(J1,I)
  800 V2=V2+S3(J1,I)
```

```
      V1=V1*.001
      V2=V2*.001
      YY=V2/(V1+V2)
      ZZ = V3(J1)*.001
      XXX = S1(J1,NYRS+1) * .001
      YYY = S1(J1,1) * .001
      ZZZ=DISCP(J1)*.001
      ZZ = ZZ - ZZZ
      XX = XXX - YYY
      XX =  100.0*XX/YYY
      VP(J1)=VP(J1)*.001
      PRINT 3300, J1,XX,VP(J1),V1,V2,YY,ZZ,ZZZ
      GO TO NPNTS, (951,952,953)
 3260 FORMAT (1H , 35X, 49HSUMMARY OF SELECTED VARIABLES FOR SIMULATION
     1RUNS)
 3270 FORMAT (1X,
     1          50H                PERCENTAGE CHANGE       CRUDE PRODUCTION ,
     2                                              6X,  23HTOTAL PROFITS AND
     3 TAX-S,4X,13HINCOME TAXES/,,4X,15HDISCOUNTED VALUE)
 3280 FORMAT (1X,
     1          50H RUN      CRUDE OIL RESERVES      (1000 OF BARRELS) ,
     2                                                        9X, 17H(1000 O
     3F DOLLARS), 7X,13HGROSS PROFITS,2X, 20HPROFITS        RESERVES)
 3290 FORMAT (1X,  6HNUMBER, 51X,
     1               7HPROFITS, 5X, 12HTAX PAYMENTS, 19X, 17H(1000 OF DOLLAR
     1S))
 3300 FORMAT (      2X, I2,11X, F 5.2,17X, F12.0, 5X, F11.0, 5X, F12.0,
     1               5X,F5.3,6X,F8.0,4X,F9.0)
      END
```

```
      SUBROUTINE RSERVE
C  CALCULATE RESERVES FOR THE SIMULATION
C
C     INCREASE IN DAYS ALLOWABLE BECAUSE OF INCREASE IN RESERVES
C
      TD = AD
      TEMP = RESERV
      IF (TEMP-BCAP)  10, 10, 5
    5 TD = AD * BCAP/TEMP
   10 CONTINUE
      VTOT=0.
      B1 = -FCOSTW * (1.-TRATE)
      B2 = DPRICE * (1.-ROYAL) * (1.-TRATE) - VCOSTR * (1.-TRATE) +
     1  DPRICE * DEP. * TRATE * (1.-ROYAL)
      YINT = ZINT / 365.
      DO 801  J=1,NN
      TSTAR = P(J,2)
      T = P(J,3)
      ARHE = P(J,4)
      XX = QZERO/QE
      TU = TSTAR +  .OG (XY) / ARHE
      TH = TSTAR+LOG(QZERO/QMAX)/ARHE
      IF (T-TU)  1801,803,803
 1801 TM = TU
      IF (TM-T)  802, 1808, 1808
 1808 TB = T
      TE = TB + TD
      V = 0.0
      FN = 1.0
 1809 QUINT = 1.0/(1.0+ZINT)**FN
      IF (TB-TM)  1812, 1812, 1810
 1810 IF (TB-TU)  1850, 1850, 805
 1812 IF (TB-TSTAR)  1814, 1840, 1840
 1814 IF (TSTAR-TE)  1830, 1820, 1820
C    CASE 4
 1820 PART1 = B1*(TE-TB)*QUINT
      PART2 = B2*QZERO*(TE-TB)*QUINT
      TSUM = PART1 + PART2
      GO TO 8200
C    CASE 5
 1830 PART1 = B1*(TE-TB)*QUINT
      PART2 = B2*QZERO*(TSTAR-TB)*QUINT
      ZZ = ARHE*(TE-TSTAR)
      PART3 = (((B2*QZERO)/ARHE)*(1.0/EXP(ZZ)-1.))*QUINT
      TSUM = PART1+PART2-PART3
      GO TO 8200
C    CASE 6
 1840 YY = ARHE*(TE-TSTAR)
      ZZ = ARHE*(TB-TSTAR)
      PART1 = B1*(TE-TB)*QUINT
      PART2 =((B2*QZERO/ARHE)*(1./EXP(YY)-1./EXP(ZZ))*QUINT)
      TSUM = PART1 - PART2
      GO TO 8200
C    CASE 7
 1850 YY = (TU-T)*YINT
```

```
      ZZ = (TB-T) * YINT
      PART1 = (-B1/YINT)*(1.0/EXP(YY)-1.0/EXP(ZZ))
      XX = T*YINT+ABHE*TSTAR
      YY = (ABHE+YINT)*TU
      ZZ = (ABHE+YINT)*TB
      PART2 = ( B2*DZERO*EXP(XX))/(ABHE+YINT)*(1.0/EXP(YY)-1.0/EXP(ZZ))
      TSUM = PART1 + PART2
      V = V + TSUM
      GO TO 806
 8200 V = V + TSUM
      TB = TE
      TE = TB + TD
      FN = FN + 1.0
      GO TO 1809
  802 IF (T-TSTAR) 804,805,803
C  CASE 1
  804 XX = (TU-T) * YINT
      PART1 = (B1/YINT) * (1. - (1./EXP(XX)))
      XX = (TSTAR-T)*YINT
      PART2 = (B2*DZERO/YINT)*(1.-1./EXP(XX))
      XX=T*YINT + ABHE*TSTAR
      YY =  (ABHE + YINT) * TSTAR
      ZZ =  (ABHE + YINT) * TU
      PART3 = (B2*DZERO/(ABHE + YINT)) * EXP(XX) * (1./EXP(YY) -1./
     1  EXP(ZZ))
      V = PART1 + PART2 + PART3
      GO TO 806
C  CASE 2
  805 XX = (TU - T) * YINT
      PART1 = (B1/YINT) * (1. - 1./EXP(XX)))
      XX = T*YINT + ABHE*TSTAR
      YY =  (ABHE + YINT) * T
      ZZ =  (ABHE +YINT) * TU
      PART2 = (B2 * DZERO/(ABHE + YINT)) * EXP(XX) * (1./EXP(YY) - 1./
     1  EXP(ZZ))
      V=PART1 + PART2
      GO TO 806
C  CASE 3
  803 V=0.0
  806 VTOT = VTOT + V * P(L,1)
  801 CONTINUE
C
C     EVALUATION OF DEPRECIABLE ASSETS AT END OF SIMULATION
C
      D=0.0
      DO 319 I=1,8
      IF(NTAX(I)-2) 311,319,31
  311 DO 318 K=2,NYRDEP
      J1=K-1
      J=1
  312 TEMP =(2.0*J1*DBAS  (I))/(NYRDEP*(NYRDEP+1))
      D=D+TEMP*RATE/(1+ZINT)**J
      J=J+1
      J1=J1-1
      IF(J1)318,318,312
```