FINDING AND DEVELOPING COSTS IN THE USA
1945-1985

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ABSTRACT

Development cost is defined as the ratio of development expenditures in a given year to reserves added in that year. Changes in development cost are a good proxy for changes in finding cost and in user cost, because discovery, development, and postponement or holding of hydrocarbons in place, are three competing forms of investment.

Popular definitions of "finding" cost are an illogical and useless mixture of discovery and development.

Although the discovery of large oil fields peaked before 1930, oil reserves added by development increased then stabilized around 1960. Costs tended if anything to decrease through 1972, but the decrease was mostly a one-time gain through the retreat from a costly regulatory scheme.

The first price explosion in 1974 saw a strong <u>decline</u> in oil reserves added. The second price explosion was followed by an increase, but the best performance since 1949-51 came in 1983-85, when oil prices were declining by nearly one fourth in real terms. High oil and gas prices promoted a drilling boom, which raised factor prices and lowered efficiency. Old-field development was therefore inhibited, but then helped as the boom deflated. Therefore the effect of the steeper price decline of 1986-87 has been mitigated by the decline in cost.

Finding and Developing Costs in the USA

Introduction The United States, excluding Alaska, is by far the largest and most intensively explored and developed oil province in the world. It is therefore the best place to study the effects of diminishing returns over time in oil and natural gas discovery and development.

Diminishing returns over time must be carefully distinguished from diminishing returns at any given time. The more wells to be drilled and reserves to be booked in a given year, the farther down the list of projects the industry goes. Moreover, haste makes waste. Therefore, under the conditions ruling at any given time, the greater the discovery-development effort, the less productive it is.

But over time, the largest fields would be found first even by chance, not to mention design; the better the drilling prospect, the earlier it is drilled. Hence over time there should be a persistent shift toward fewer and poorer reservoirs. The supply curve would move counter-clockwise, all else being equal, and the price would rise. (Below, Figure 5)

In the United States, by the end of 1945, 1.3 million wells had been dug, and 32 billion barrels produced.[API 1959] The industry was far down the discovery curve. Of the largest 186 fields in the "lower 48" (i. e. excluding Alaska) known in 1985, 120 had been found before 1945, and they contained 76 percent of all the oil in the group. (Below, Fig. 1) In 1945, there were only 20 billion barrels left in "proved recoverable reserves" [API-AGA 1946]. Yet through 1985, the United States, excluding Alaska, produced not 20 but 100 billion barrels.

It has been shown that reserves in known oil and gas fields continue to grow for decades after supposed maturity. Moreover, the growth of reserves in known fields in the USA after World War II was about equally divided between higher recovery rates and new oil in place [AHKZ 1983, ch. 6]. Proved reserves are only the ready shelf inventory of the industry, which keeps re-stocking the shelves by drawing from some undetermined amount "out there".

Diminishing returns have been extensively analyzed by estimating and projecting reserves and production. [For recent surveys: see Meyer & Fleming 1985, Woods 1985] The best-known example of the physical approach is that of M. King Hubbert. He fitted a logistic curve to past production, and extrapolated it to predict future production, on the principle that the area under the ultimate curve was the original finite amount. After the peak, production would turn downward at a rate which would first accelerate, then flatten, converging toward zero.

Hubbert's prediction of 1970 as the peak production year was correct, apparently the only good prediction known to students of the oil industry. The objections of John M. Ryan, that the curve had no logical connection with the actual process of finding-developing-producing, seem never to have been much regarded. [Hubbert, 1962. Ryan, 1965]

U.S. oil production in the "lower 48" declined slightly for a decade, but after mid-1980 remained quite steady. The industry seemed to take an unconscionably long time dying. Perhaps the higher prices were a reprieve, but there were also much higher costs. The much lower prices of 1986 are perceived as promising lower reserve-additions. The key is in the price-cost relation, which the volumetric approach ignores.

The problem can be posed by taking successive snapshots [OGJ 1943, OGJ 1987] of two large oil fields (all amounts are in millios of barrels):

	Kern River (disc. 1899)	East Texas (disc. 1930)
End-1942 reserves:	54	2600
Cumulative production, 1943-86	736	3031
End-1986 reserves:	970	1200

In more recent experience: the Prudhoe Bay field was rated for years at 9.6 billion barrels recoverable reserves. Early in 1987, it produced its 5-billionth barrel, leaving, one might suppose, 4.6 billion. But this was becoming increasingly doubtful because the expected decline in output was postponed from year to year. In fact, an informed estimate shortly thereafter was of 8.2 billion, including 0.4 billion natural gas liquids. [Salomon 1987]

The additional barrels in large as in small fields were no gift of nature, nor did they reflect any "conservatism" in the original estimates. On the contrary, they were acquired by heavy investment both tangible and intangible. Our objective is to measure the relation between discovery-development investment and reserve-additions since World War II.

<u>Some costs and pseudo-costs</u> Many cost figures are mentioned these days, but usually the sources and methods are not explained. Often there are obvious errors in one or both. For example, "finding costs" are often used to designate the sum of development and exploration outlays. [Andersen 1985] But this adds apples to oranges, and it compounds the error to compare the sum of the expenditures with the reserves described as "found" during the year. The reserves discovered through the finding effort of a given year will nearly all be booked in later years. As for money spent for the acquisition of acreage, that is not a cost at all, but a transfer payment.

Second, they add oil and gas, which have been subject to different forces, and reacted differently. This multiplies the effect of the first error. If Company A develops oil and B explores for gas, we add their expenditures, divide by Company

A's reserves-added, and are alarmed at the average "finding cost". Each company knows better.

Third, the basic data are seriously biased downward. Thus a compilation for 30 large companies, which account for about two-thirds of liquids reserves [Picchi & Winnall, 1986] has them replacing only 81 percent of their production in 1985, only 63 percent for 1978-85 inclusive. (We exclude purchases.) But the corresponding Department of Energy totals for the whole industry were 134 and 112 percent.

These and other errors which we cannot trace cumulate into estimates of "finding cost" which are flights of fancy. The most notorious though not the worst example was the damages award in the Pennzoil-Texaco case. (We state no opinion on the legal question at issue, whether there existed a valid binding Getty-Pennzoil contract.) Pennzoil had paid about $3.40 per barrel for Getty's oil reserves. It claimed that the replacement cost by drilling would have been $10.87.[1] One need not believe that capital markets are perfect to see that such a 3:1 discrepancy between market value and replacement cost is ridiculous. Even more wild is an estimate submitted in October 1986 to the IPAA (which, we stress, was not their work) that "replacement cost of

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[1] Thomas Petzinger Jr., "Texaco v. Pennzoil, Anatomy of a Jury's Deliberations", Wall Street Journal, May 8, 1987, p. 7.

crude oil was over $26.50 in 1984, but if one adds financing costs the totals go much higher". [IPAA, 1986]

"Financing costs" are the cost of holding the asset oil-in-ground until it is extracted. For this reason, as we show below, oil at the wellhead has a cost or break-even price roughly three times as much as the capital cost or value of oil-in-ground. Hence this measure of so-called "finding cost" translates into a wellhead cost of about $80. In fact, even $26.50 as the in-ground cost is overstated by a factor of about six (below, Table II).

A recent article [Desprairies, Boy de la Tour, Lacour 1985] has some fairly elaborate cross classifications of reserves by cost category, but provides no hint of sources or methods. Moreover, a cost of $20 per barrel is said to be "compatible with a market cost of around $30/barrel" [p. 523], which sounds as though there is some additional undisclosed element. This mystery about the concept of cost makes it impossible to use.

Sometimes it is not even necessary to learn <u>how</u> an estimate was made to see that it is impossible. For example, there have been frequent references to an estimate that outside OPEC it takes $70,000 to find and develop one additional daily barrel of capacity. [OECD 1985, Ebinger 1985, Banks 1985] This is presented as a worldwide parameter, to which the industry and its customers must adapt.

But a little mental arithmetic shows this estimate to be impossible. In the United States, the cost of capital on equity funds is about 10 percent real, i. e., assuming oil prices will move with the general price level. A rough average decline rate is around 12 percent (below, Table III). Assume 35 percent for royalties, state taxes (not income taxes), and operating costs (below, Table V). Spending $70,000 for a daily barrel only makes sense if the price is at least $65 per barrel, and is expected to rise with the rate of general inflation.[2]

During the delirium of 1979-81 many oilmen expected such prices--some day. But it passes all credulity to suppose that they have on average been spending this, year in year out--without losing their shirts, their jobs, or their companies to takeovers or stockholders' suits.

In 1985, a barrel of developed reserves in the ground sold in the USA at $6 per barrel ([OGJ 1985c]). Now, $6 per barrel in ground equates to $20,300 per initial daily barrel of capacity (below, Equation [2]). Rational people will not spend the equivalent of $70,000 for what they can reproduce for less than one-third the amount.

The $70,000 per daily barrel delusion is a useful reminder. A cost estimate needs to be validated by reference to the relevant price. If it passes the test, it may still be wrong,

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[2] That is, ($70,000/365)*(.12+.10)/.65 = $64.91.

but if costs are far above prices, the estimate must be rejected, and the estimator must go back to the drawing board.

Theory

Costs are measured as an investment outlay versus (1) new reserves in the ground, or (2) new productive capacity.

There is a basic relationship between (1) and (2). Proved reserves are the amount which will ultimately be produced out of a pool by the capacity of facilities in place. Hence if R = reserves, Q = initial output, and a = the exponential decline rate, then:

$$R = \int_0^T Q\, e^{-at}\, dt = Q/a * (1-e^{-aT}) \qquad [1a]$$

As T becomes large, R approaches Q/a, or a = Q/R. [1]

With normal pool lifetimes, the error in using infinite time is usually but not always negligible. The depletion rate is only an approximation to the true decline rate, and is subject to biases up and down. (For a fuller discussion, see [AHKZ 1983, Appendix B.])

In the United States, good data exist on annual increments to proved reserves, and development costs can be calculated as dollars per barrel added in the ground. But with Equation [1], that figure can be translated into outlays per initial barrel of capacity, and checked against independent data.

For example, if K = investment, and K/R, the cost of installing facilities which will enable us to book one barrel in the ground, then the investment per additional daily barrel in the US in recent years, when the decline rate a was about 0.12:

$$(T \to \infty) \qquad K/Q = 365\ (K/Ra) = 365K/.12 = 3042\ K \qquad [2]$$

$$(T=25) \qquad K/Q = 365\ (K/Ra)(1-e^{-aT}) = 365K/.113 = 3230K$$

Conversely, if we learn that the investment per daily barrel is e. g. \$20,000 per daily barrel, the investment per barrel in-ground is about \$20,000/3230K = \$6.19.

Moreover, as indicated earlier, the producer needs to hold the asset, as a stock of proved reserves, until he sells it off. Thus the real supply price must allow for the ratio of above-ground to in-ground values.

Defining K, a, R, T, and Q as before, we add i, the minimum acceptable rate of return, and P as the market value.

Undiscounted value of in-ground reserves = $PR = PQ/a$

Discounted present value above ground =

$$PV = P_Q \int_0^{\infty} e^{-(a+i)t}\, dt = PQ/(a+i) = PR\ (a+i)/a \qquad [3]$$

Then in equilibrium the <u>value</u> of a discounted above-ground unit relative to an undiscounted below-ground unit is approximately $(a+i)/a$. What comes to the same thing, the <u>cost</u> of holding the inventory below-ground until the time of production is:

$$(T \to \infty) \qquad (a+i)/a = 1 + (i/a) \qquad [4]$$

$$(T=25) \qquad ((a+i)/a) = (1-e^{-aT})/(1-e^{-(a+i)T}) \qquad [4a]$$

Assuming R/Q = 12, i = 0.1, the cost of holding is 1.833 assuming infinite time, and 1.783 assuming 25 years.

Thus a barrel or mcf above ground is barely worth buying at a price which is (1+(i/a)) times the price of a unit below ground. Contrariwise, if a unit above ground cannot be expected to sell for (1+(i/a)) times its cost to create under ground, then it is not worth creating.

Obviously, the higher the discount rate, and the longer it takes to get the oil or gas out of the ground (reciprocal of a), the more expensive is the oil or gas. The faster the depletion, and the shorter the holding time, the better--all else being equal.

But faster depletion takes more investment. Hence the optimum depletion rate is a tradeoff between higher investment and quicker return. (Of course, the depletion rate may be limited by government, or by some kind of monopoly arrangement limiting investment and production.)

But, instead of depleting a pool faster and more expensively to get more production, at some point it pays to incur the costs of <u>finding</u> an additional pool. Thus development and exploration are limited substitutes for each other. This is a hint that will be followed up later.

Data: expenditures and reserve additions

[TABLE I HERE]

Column 1 of Table I presents a series for converting nominal into constant-dollar expenditures.[3]

In cols. 2 - 7, using column 1 as deflator, we show expenditures made for finding and for developing, 1955-1986. The Joint Association Survey is the source for 1955-72, the Census Bureau for 1973-82. The estimates for 1983-86 are approximations based on the J. A. S. drilling expenditures, since total exploration or total development are no longer available from any source.[4]

The expenditure series have been purged of lease bonuses or lease rentals, which are not costs, but rather transfer payments, that is, a share of past or expected profits, paid to the landowners, chiefly the U. S. government.

The division of exploration expenditures between oil and gas is proportional to the number of successful exploratory wells for

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[3] During 1963-85, this is the drilling cost index of the Independent Petroleum Association of America [IPAA 1963-85]. During the years of overlap 1963-73, changes in the IPAA index were very close to those in the GNP:IPD price index of "non-residential gross domestic business investment". The two diverged sharply after 1973, an important fact to be discussed below. But it enables the use of the "business investment" index as a proxy for the IPAA index for years before 1963.

[4] In March 1986, the API resumed publication of a comparable series, starting with the year 1983.

each; total development expenditures are divided between oil and gas in proportion to drilling expenditures respectively on development oil wells and development gas wells.

[TABLE II HERE]

In Table II, the deflated expenditures of Table I are divided by reserves-added, to obtain the cost per unit added. The reserve additions were published for many years by the American Petroleum Institute and American Gas Association. [API-AGA, 1959-76; API-AGA & EIA 1977-79; EIA, 1980-86] They are understated because of the omission of natural gas liquids, which, following the EIA takeover of the reserve statistics, are no longer compiled by origin. [EIA letter 1985] It is an unfortunate gap, but with little effect on the observed trend.

Increments to gas reserves include only non-associated gas, since we are trying to match them with drilling and equipping and other expenditures on new gas wells. This again gives some understatement because some part of the expenditures for crude oil development is for the production of associated-dissolved gas.

An alternative series shown below (Table IV, Figure 6) is essentially a combined finding-developing cost per barrel.

[TABLE III HERE]

Table III shows some factors bearing upon cost changes: the depletion rate, cumulative production, number of development wells drilled, and total drilling expenditures per rig year, a rough indicator of efficiency.

The increase in drilling expenditures per rig year appears to be an anomaly, given the efficiency increases that have occurred in the industry since the post-1979 drilling boom. Certainly the increase in the number of wells drilled per rig-year acts to offset the rise in expenditures per rig-year, but a decrease in expenditures would still have been expected, or at least stability, not an increase. The explanation for this result is derived, at least in part, from the fall in the drilling price index (Table I) which offsets the drop in nominal drilling expenditures.

It might at first appear that these reserve and expenditure data were so highly aggregated as to be useless. After all, they include a very large number of fields and reservoirs, and a wide range of recorded costs. And it is true that if these data aggregated the <u>average</u> or <u>total lifetime</u> cost of many reservoirs, the result would not be interesting. But a single year's data record <u>incremental</u> (not average) cost across all reservoirs developed. The industry is a selective mechanism for maintaining or expanding output at the least cost. Under competitive conditions (which hold in the USA though not in the world industry), marginal cost everywhere moves toward the expected price. Lower-cost reservoirs are expanded to the point where rising costs choke off additional drilling. Higher-cost reservoirs are drilled more selectively, to bring down incremental costs, or are not drilled at all. The industry is forever approaching the long-run equilibrium, which of course it never attains. (The excluded transfer payments equalize private marginal costs, not social costs.)

Of course, there is still a great variability among new projects, some real and some artificial. On the low side: new low-cost reservoirs are drilled up only gradually. Costs are abnormally low at first, then rise as they approach marginal equality. This biases the total down. Contrariwise, the early stages of any project are outlays with nothing to show for them, which biases the total expenditure up.

Indivisibilities are also a distortion. Incremental cost in a pool may be below the price, but more intensive development would require so large an additional investment, e.g. another platform, that its cost would exceed the price. More generally, too high a production rate will damage the reservoir and exact a very high cost; best not to approach the edge of the cliff.

So far, reserves <u>developed</u> during the year have been discussed. Oil in newly found fields and pools can only be roughly estimated, as the AAPG does annually. [AAPG, annual]. For those years where they overlap, the AAPG estimates are below the API, and I would consider them downward-biased. [Meyer 1985,

p. 1953] Back-dated estimates made years later are much more accurate.

No use is made here of the item "discoveries" in the API-AGA or the current EIA publications. These "discoveries" include only that small part of newly-found fields that has actually been booked, i.e. developed and made ready for production in the given year. The eventual reserve figure is several or many times the initial estimate, with great variation among fields, regions, and years. Hence the annual "discoveries" number is meaningless, a fragment masquerading as data.

For the Province of Alberta in Canada, there are back-dated discoveries, year by year, and by fields, since 1947. [Alberta 1984] [Uhler & Eglington 1986]. For the United States, similar numbers by states (but not fields) are available from 1921 through 1979. After that year, the API-AGA statistics were replaced by a Department of Energy series. Unfortunately, this was based on a sample of operators not fields, and the back-dated estimates could no longer be made. And since it takes about six years to get a reliable estimate, the usable back-dated entries end in 1973. A panel appointed by the National Academy of Sciences has criticized this procedure [NAS 1985], and pointed out the statistical gap.

Since fields continued to grow after 1973, even the API-AGA series is too low. Hence we cannot use it to calculate unit costs. Even if we did, since a biased series might be better than none, a given year's "cost" would not be comparable with, nor additive to, the same year's unit development cost. Below, we will show how changes in development cost are a proxy for changes in discovery costs; and how discovery values may be estimated from reserve values and development costs.

Discussion: Graphic Summaries

Oil & Gas Discovery

[FIGURE 1 HERE]

Figure 1 is based on the original reserves credited as of the end of 1985 to 186 large fields which account for approximately 50 percent of total U. S. reserves. The lower line shows the percentage credited to fields found during the decade ending in the year shown. Thus fields found before 1900 contained about 5 percent of the total, 1901-1910 discoveries about 7 percent, etc. Oil discoveries peak in the decade 1921-1930, with about one-fourth of the total, after which the decline is rapid to 1960 and thereafter.

The upper curve cumulates the decades. It shows, for example, that about 80 percent of the oil in these large fields discovered through 1985 was in fields discovered before 1945.

[FIGURE 2 HERE]

Figure 2 shows the trends in backdated discoveries of oil and gas in all fields, large and small, during 1920-1973. The oil line checks approximately with the trends shown in Figure 1, with the same peak before 1930, and the severe decline since. The AAPG series (not shown) at least suffices to show there was no reversal of the decline after 1973. Nonassociated gas discoveries are dominated by the spike in 1922; another much smaller peak is in 1951.

[FIGURES 3 & 4 HERE]

Figures 3 and 4 show 1955-86 expenditures on exploration and development, for oil and gas, in current dollars and constant dollars, respectively.[5] In oil, there was a slow decrease in real expenditures through 1973, while gas shows a drop in the later fifties, and a rough constancy afterward. Then comes the big boom. Stated in real terms, oil development expenditures decline sharply after 1955-56, while the other classes remain stable.

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[5] During 1955-1982; designating oil development wells as OWLS, the cost index as IP, reported oil development expenditures could be fairly well estimated by:

$$\text{Expenditures (\$billions)} = \$7.6 * OWLS^{0.72} * IP^{1.03} \qquad [5]$$

The standard error of estimate is 8.6 percent.

Incidentally, the number of wells, and the IPAA drilling-equipping cost index, are reported promptly. Using them to estimate expenditures normally saves one to two years.

Oil Development Costs

As stated earlier, diminishing returns in finding new fields and pools are to be expected. Development investment would at first seem to be an activity of gradually increasing efficiency because of progress in technology. But this is only true ceteris paribus, when considering a given operation, e. g. drilling to a given depth in a given place. It is not true of the observed development cost at any time.

If newer fields are getting smaller, deeper, more heterogeneous and faulted, etc., then development cost per unit of reserves booked in those new fields must also increase.[6]

Moreover, when it becomes increasingly difficult to find new oil fields as good as those previously discovered, the alternative of more intensive development in the old fields becomes more attractive. Thus more development wells will be drilled into and near the older pools.

Finally, the higher the cost of new oil, the greater the incentive to drain the old oil faster, even at the cost of higher investment requirements. As seen above, the higher expenditures are to an important degree offset by the faster payout. Of course, in each reservoir, a point is reached where faster

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[6] Suppose all pools to be at the same depth, circular, and homogeneous. Then the total number of wells drilled will be proportional to area. The number of dry holes will be proportional to the circumference which they outline. The ratio of circumference to area is $2/r$, where r = radius, so the smaller the area the higher the dry-hole ratio. Increasingly heterogeneous reservoirs are in effect smaller circles, with higher dry-hole ratios. Non-circular areas have a higher ratio of circumference to area.

depletion would be inordinately costly because it would damage the reservoir.

Thus for three (not wholly independent) reasons, oil development cost changes reflect discovery cost changes: as the crop gets more scanty, more development effort is needed to process it. Hence oil development costs are a proxy or indirect indicator of changes in finding cost.

The general principle is: at the margin, another unit of investment ought to bring the same return in development as in exploration. With lower development cost _ceteris paribus_, the shift toward development from exploration relieves the pressure on exploration, and stops when marginal returns are again equated.

It is natural to think of discovery and development as complementary, and so they are in any given project. The higher the expected finding cost, the lower must the development cost be for the project to be acceptable. But outside of a relatively small number of projects in the early stages, discovery and development are overwhelmingly substitutes not complements.

A measure of changes in finding-developing-producing cost

The unit costs calculated above, dividing expenditures by reserves-added, are deficient in that they must to some extent reflect movements along the supply curve, when we are trying to isolate the movement of the curve (see above, p. 1).

[FIGURE 5 HERE]

In Figure 5, reserves-added are plotted on the horizontal axis, price on the vertical. Each of the three observed points represents the intersection of the year's supply curve with the year's demand curve. The curve must pass through the origin, since with a zero price there would be zero reserve-additions. Dividing the Y-value (price) by the X-value (reserves added), yields the average <u>slope</u> of the supply curve. Thus if the price were $10 and 10 units were supplied (S1), then the slope would equal unity. If, at the same $10 price, only 5 units are supplied (S2), then the slope of the curve is 10/5 = 2. In Figure 5, we have also drawn in a non-linear supply curve, which seems more realistic. But even if we supposed that the shape changed over the years, the increasing slope of the curve would signal rising costs, even if we knew nothing about the slope of any particular curve. Moreover, the supply price shown in Figure 7 includes discovery or in-ground value, development cost, and current producing cost.

[TABLE IV; FIGURE 6 HERE]

Table IV, and Figure 6, show the slope of the price: reserves-added relationship over a 55 year period. From 1918 to 1929, when discoveries were increasing, the slope decreased by a factor of about 6, despite much fluctuation. Omitting the depression outliers of 1930-37, when investment dwindled and reserves-added went nearly to zero, a small net decrease is apparent. For the next 36 years, when exploration dwindled rapidly, the supply curve showed no leftward rotation.

A similar price/reserves plot for natural gas is not posssible, because the published "price" of natural gas is merely the arithmetic average of all prices on old and new contracts, inter-state and intra-state, in no way comparable with current costs, hence with no meaning for supply. Of course they were in any case distorted during the long period when gas prices were under control--as, indeed, many still are--and were forced artificially high or low.

[FIGURE 7 HERE]

Figure 7 shows, for the period since 1955, both measures of the cost of oil, together with the development cost of gas. The two oil measures move generally together, but the price of gas shows little relation, until of course the 1970s.

Development Costs 1973-85

There was a sharp break with the past after 1972, and both development costs and total costs increased very greatly, for various reasons. Wells drilled rose by a factor of 3.25. The demand for oil and gas drilling-equipping services greatly exceeded supply, which could not be quickly expanded. Hence the price of drilling-equipping services rose very sharply. But even adjusted for factor price changes, the real cost approximately doubled over that time, whether measured by outlays per reserve barrel added, or by the price of oil related to reserve barrels.

Obviously, the services were used much less efficiently. Anecdotal evidence abounds. It is all too credible that kickbacks inflated drilling costs 30 to 40 percent in some instances. [WSJ 1985] But my own conjecture is that the use of untrained personnel, and the hoarding of men, materials, and machines, were much more important. In any case, the return to drilling investment had to be less, as the industry moved up the short-run supply curve.

[FIGURE 8 HERE]

Figure 8 shows that during 1949-1968, although well depth increased, the number of wells drilled per rig-year persistently increased, showing increasing efficiency. During the next five years, well depth continued to increase, and wells per rig year decreased, indicating perhaps unchanged efficiency. But after 1973, although average depth decreased, wells drilled per rig-year continued to decline, indicating a loss of efficiency, until the startling reversal after 1981.

In an effort to separate well depth from intensity of use, an ordinary least squares regression was done, with wells per rig year as the dependent variable. The DOE revised well completion series was used for 1973-85, and estimated back to 1967 by applying the 1973-77 ratio of the DOE series to the API series (1.055). The independent variables are (1) the ratio of active rigs to all rigs, as tabulated starting 1967 by Reed Tool Co., and (2) the average depth of well. If WRY = Wells per Rig Year, PAR = Percent of Active Rigs, and AWD = Average Well Depth, then the estimating equation is:

$$WRY = 14.3-0.49(\ln PAR)-1.32(\ln AWD) \qquad [\ 5\ ]$$

Thus for every additional percent of rig capacity utilized, the number of wells per rig-year fell by 0.49 percent; for every additional percent of average well depth, wells per rig-year decreased 1.32 percent. The R^2 was .78, F-statistic 32, respective t-statistics 3.8, 4.9, 3.0. This looks robust, but the extremely low Durbin-Watson (0.95) downgrades the significance. As usual, the small sample and much collinearity take their toll. However, it seems clear that there has been a great short-term gain in efficiency, which may have more than undone the waste and misdirected effort of the 1970s.

One hesitates to credit a doubling of efficiency (wells or footage drilled per rig year) in only the five years 1981-86. The mix of wells, as between oil and gas, deep and shallow, etc., must have changed. But a special tabulation done at Baker Hughes, which allows for these changes, shows an increase of over 70 percent. My own conjecture is that these gains were made slowly and incrementally since 1973, but were masked by the gross inefficiencies unleashed by the drilling boom. As activity slumped after 1981, the gains quickly appeared. We should not, therefore, expect to see them continue for long.

An attempted explanation. We now try to draw the threads together, and first try to explain to some degree why costs were stable or possibly even decreasing during 1955-72. It takes some explaining because cumulative output went from 33.2 billion barrels end-1946 to 103.4 end-1973. Proved reserves of 21.5

billion at the end of 1946 were used up and replaced three times over during the next 27 years, each replacement from fields inferior to the previous.

An exogenous factor was the decline, after 1949, in the real price of oil in the United States, following trends in the world price, although it was always considerably higher.

Imports were subject to quotas, first informal, then "voluntary", then mandatory. But I think it was well understood by the late 1950s that further price increases would not be tolerated, and might lead to loss of quota protection. Indeed, the struggle over oil imports was never-ending. In 1969, the Nixon Administration undertook a review of the whole import question, by a task force under the general direction of George P. Shultz, which favored abandonment. [Shultz et al 1970]

The import quota had sheltered a system of market demand prorationing which restricted output, and favored small unproductive wells. It was often profitable to drill many more wells than needed to drain a reservoir optimally. The additional wells brought no additional capacity, only increased production "allowables". [Adelman 1964.][7]

As the real price slowly declined, these wells were curtailed. Moreover, poorer prospects were no longer drilled. As Table III col. (5) shows, the number of oil development wells fell drastically, from 29 thousand in 1955 to 9 thousand in

[7] This paper received the accolade of its author being denounced by name by the then Governor of Texas, Mr. John B. Connally.

1973. (Gas development wells actually rose.) By that time, production was no longer restricted by market-demand prorationing.

[FIGURE 9 HERE]

The result was a one-time gain in efficiency, the precise amount of which is impossible to measure. This must account for some part of the substantial oil cost reduction during a period of massive resource depletion. As Figure 9 shows, there was no corresponding decline in gas costs.

But from 1973 through 1976, the oil industry reacted to the increase in oil prices by bidding up factor prices even faster; while real costs rose faster yet. It is a tribute to the power of expectations, and of course a classic example of the accelerator-multiplier principle.

By 1978, this had been largely corrected, and the price-cost margin was again at about the 1973 level. But then came the even larger price jump of 1979-81, and an even stronger industry reaction. Nothing was too extravagant, since everyone knew that the price of oil was going to $100 or $200 by the end of the century. At the same time, gas price regulation had generated excess demand, and focussed all of it upon a small number of exempt sources of supply: recently or newly found gas, imports, and deep gas whose price touched $9 per Mcf.

The bubbles began to burst after 1981, but the effect was two sided. Footage drilled per rig year, for example, which had fallen from 125 thousand in 1972 to 102 thousand in 1981, rose to over 200 thousand at the end of 1986, and was still rising in early 1987. To be sure, such comparisons are always distorted by the shift in the mix of wells, oil and gas, shallow and deep, productive and dry.

In any case, the fall in factor prices was such that the producer's real price of oil actually increased, while development cost fell again. By 1984, it was at about the 1955-63 level. Despite the sharp decline in rigs running, there was only a mild decrease in oil development wells drilled. The volume of oil reserves-added in 1983-85 was a near-record for any three years, exceeded in the lower 48 only in 1949-51.[8] [API 1959, API 1979, EIA 1986] Cost inflation and inefficiency cut so sharply into the incentive of higher prices, that it is hard to discern the net effect of the price increase. Conversely, the price decrease since 1981 has been buffered and offset by the decrease in costs.

Multiple regression analysis is the standard way of sorting out such effects, but the barriers are formidable. The obvious candidates for independent variables are the number of oil development wells and/or some other index of intensity of use, to register the movement along the supply curve; cumulative production, to register the depletion effect which displaces the whole supply curve; and the depletion rate or production/reserve ratio, which pertains to both kinds of effects. The higher the

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[8] Reserves-added in 1986 were less than half of the 1983-85 average, but more than the lows of 1977, 1979, or 1982, when real (inflation adjusted) oil prices were higher.

depletion rate, the greater the shift away from exploration and toward development as a source of reserves. It was pointed out earlier that these were substitutes, hence proxies, because the more expensive it became to find new fields, the greater the inducement to increase drilling in and around old fields, and produce at higher depletion rates.

But all these variables are highly intercorrelated, and each is serially correlated with itself. For the period before 1974, no regression showed any relation. The appearance of a relation comes only when one includes the later years, which makes the results unacceptable for any attempt to explain the depletion effect upon costs. Possibly a much larger scale study, combining time series with cross-sections by states, could fill the gap.

[TABLE V HERE]

<u>Regression study of reserves added</u> Table V shows the results of a somewhat different approach: explaining the changes in annual crude oil reserves-added by cost and price factors.

Equations 5-7 and 12-14 show the explanatory variables as the nominal price of crude oil, and the IPAA drilling cost (factor price). In both the arithmetic and logarithmic version, the factor price variable is stronger. Suppose that both variables double. "Real price", as defined here, would be unchanged. But since $2^{-1.23}*2^{0.74}=0.71$, reserves-added would drop by 29 percent. Apparently, the drilling cost variable incorporates not only the effect of drilling cost, but also the effect of lower efficiency, with which it is strongly correlated.

We must recognize an identification problem. Reserve--increments (the dependent variable) have no effect on the price of oil, nor on cumulative depletion. But they do have an effect on the index of factor prices (IPAA). The greater the inputs into oil development, the greater the reserve increments, and also the greater the pressure on factor prices. This may be tolerable because most inputs are on exploration and on gas development. But to some extent it impairs the relationships measured in Table V.

Equations 3-6 and 10-13 incorporate the effect of cumulative production. Taken in isolation, Equations 3 and 10 have the right sign and a good t-statistic. But when allowance is made for the effect of prices and costs, the coefficients are small and insignificant. The effect is complex. Cumulative depletion registers cumulative learning. Hence the attempt to use a quadratic function to capture also the ultimate resource-exhaustion effect. But nothing can be observed.

We look now at the outstanding anomaly, the extraordinarily bad performance of the mid-1970s, when a huge upsurge of exploratory and development drilling coincided with a very low level of reserves-added. There would be no mystery if the drilling boom were exogenous, and simply imposed higher money and real costs. But this is not so; the drilling upsurge was a response to perceived profit opportunities. It is difficult to get inside the mystery because of the wide variation in oil prices at any given moment. For many leases whose output was under price control, further development drilling was unprofitable. Yet for the whole producing system, the desired level of drilling plainly exceeded what could be done.

Analysis is the more difficult because after 1973, averages of price and cost become unreliable because of price regulation. Moreover, the reserves-added data are also less reliable.

[FIGURES 10 & 11 HERE]

Figures 10 and 11 show another physical indicator of cost: average daily output per oil well and per gas well. In oil, there is a slow increase after 1958, peaking in 1973 and declining thereafter, but still well above anything before 1967. In gas, there was a persistent decline in California and Texas. The increase in Louisiana reflects the growing importance of offshore production. The Louisiana decline after 1974 shows a substantial decline in efficiency, or increase in cost.

Finding Costs, Development Costs, and Resource Values, 1970-1985

The value of any asset, in any industry, is equal to the lesser of (a) the present discounted value of its future surplus over operating costs, or (b) its replacement cost. This ratio has become well known as "Tobin's Q". In a mining industry, as we have emphasized, replacement may be had by (b_1) development or (b_2) exploration.

A developed or undeveloped barrel in the ground is an asset, governed by the general rule. Value and replacement cost are always gravitating toward each other. The higher the value, the greater the finding incentive and investment. This drives up the cost. Conversely, the higher the cost of finding, the greater the value of a barrel already found.

In whatever industry, nothing is more difficult than predicting future returns from holding an asset for later sale. Yet owners must make the comparison with replacement cost as best they can, and decide whether or not to invest or to disinvest, i. e. sell off some of the asset.

When oil prices are under pressure, we hear ad nauseam about the foolish oilmen who will sell off "the incremental barrel" at anything over bare operating cost. In fact, they will do no such thing, unless they think the whole industry is liquidating, and prices will never recover. Otherwise they must take into account the value of the asset they consume: reserves.

Prices soften or decline when they are too far above the <u>total</u> of operating costs <u>plus</u> development cost <u>plus</u> the lesser of resource value or marginal finding cost. We should not lose sight of the fact that in the areas holding most of the world's reserves, a price as low as $10 is still very high compared with the sum of the three. Our current concern, however, is with the United States.

We propose to show the relation by first estimating what price above ground would barely compensate the investment calculated here, and comparing this supply price with actual above-ground prices.

[TABLE VI HERE]

Table VI shows oil and gas revenues during 1955-83, first gross then net of operating costs, taxes, and royalties. The ratio stayed within a narrow range of 35 to 37 percent before 1974, but then declined mildly as prices outran costs, and then jumped with the imposition of the misnamed Windfall Profits Tax in 1981.

We turn now to the comparison of in-ground values with prices and costs. Published estimates of current values are based on current sales of properties. The sample for any one year is very small. The dispersion is great, since each sale is a single payment for a bundle of oil, gas, and many special features, good or bad. It becomes hard to discern the values of the oil or gas reserves as such. Moreover, published results are "oil equivalent barrels", mingling oil and gas together.

A recent paper [Adelman, DeSilva and Koehn 1987] tabulates the individual company estimates issued by the John S. Herold Company beginning 1946. They calculate the present value of the proved reserves, expected to be depleted in some trajectory over time, and discounted at what is considered an appropriate rate.

The Herold valuations are not market data. However, they are themselves subject to a market process: the nearer they come to what investors consider reasonable, i.e. would pay or demand, the more successful they are. The survival of the company for this long a period indicates that they have been acceptably close; and the Herold valuations are frequently referred to and quoted in the financial press.

[TABLE VII HERE]

In Table VII, columns (1) and (2) shows the average wellhead price of crude oil, and the price net of operating expenses, royalties, State severance taxes and (in recent years) the Windfall Profits Tax, which is an excise not a profits tax. For 1955-82, there are actual data on these deductions. Since as shown in the previous table the dispersion about the period mean is quite small, it seems safe to extend it forward and back.

Column (3) shows the annual average value of proved reserves of crude oil in the United States. Outside this country, not only are reserves calculated differently, but the risk and discounting factors are different.

[FIGURES 12, 13, AND 14 HERE]

Figure 12 shows the salient values: prices, values and costs over a 40-year period. Because there is such a violent break at 1973, Figures 13 and 14 show the earlier and later period separately. These figures are all in nominal (current) dollars. In real (inflation-adjusted) terms, they all decreased through 1973.

For many years, the industry has had a rule of thumb of in-ground value as one-third of the wellhead price. It seems to be well supported. Figure 15 (lower line) shows value is mildly below one-third before 1973, mildly higher afterward.

[FIGURE 15 HERE]

Column (4) of Table VII recapitulates the development cost estimates from earlier tables. Column (5) adjusts it for tax benefits which lowered the net cost to the investor, more substantially before 1975, when percentage depletion was repealed. Since value is also after tax, this is necessary to make the cost comparable with the value. The average ratio of value to post-tax cost over the whole period 1955-88 is 1.6. (The only years with values below unity are, significantly, during the very disturbed if profitable years since the first oil shock.)

The excess over unity, stated in column (6), is equal to user cost, the present value of future use. It is the pure resource value sacrificed by choosing to develop today rather than later. A developed reserve is worth the present value of revenues less operating outlays, but an undeveloped reserve is worth only revenues less the sum of operating outlays plus development cost. Therefore, if one subtracts out development cost per unit from reserve value, one has the pure resource value of a unit in the ground. In equilibrium, user cost equals discovery cost, and should indeed be regarded as a rough estimate, especially when averaged over a period of years.

[FIGURE 16 HERE]

Figure 16 shows user cost in 1955-86. In nominal terms it was quite stable through 1973, and paralleled development cost. This confirms what we concluded in reviewing the theory: development cost and exploration cost move in parallel because they are substitutes for each other. The years 1975-76-77, and 1982, showed negative user cost. I think it is significant that these were all unusually bad years in terms of reserves-added.

Price expectations and asset values. In general, a long-lived asset rises in price when the market expects an increase in the prices of the goods in which the asset will be embedded through future production. Hence asset price changes are a leading indicator or forecaster of product price changes. There was no indication of higher user cost, hence future higher prices, before 1973, which suggests that there was no room for higher prices within the framework of expected supply and demand.

Table VII permits us to restate equation [4]:

$$V = Pa/(a+i-g) \qquad [6]$$

where the net present value of a barrel in-ground is the net price above-ground, discounted for the cost of holding the undepleted portion over the remaining lifetime of the pool. In equation [6], we have introduced a new parameter g, the rate at which the price is expected to rise.

According to the well-known "Hotelling valuation principle" (HVP) [Miller & Upton 1985], the price of a mineral is expected to rise at the riskless interest rate, since at a lower rate the owner of the deposit would be losing what he could earn by selling the mineral and investing the proceeds. But a given percent rise in the price is equivalent to a decline in the interest rate. Hence in equilibrium g = i. If so, Equation [6] reduces to V = P, the value of the deposit equals the current undiscounted price. The elegant simplicity of this principle is attractive. But it is contradicted by the data of Table VII. See Figure 15 again.

The HVP cannot work because the owner of the reserve cannot in fact extract and sell it off entire. At most he can deplete a minor fraction in any given year. The faster he depletes, the higher the present value. This relation is embodied in the reservoir engineer's "deferment factor", which is proportional to the reserve-production ratio. The lower the deferment factor, the higher the ratio of discounted to undiscounted value. [Production Engineering Handbook 1987] But the lower the deferment ratio, the higher the cost. Optimal depletion therefore involves a tradeoff. We can see how the one-third rule embodies this fact if in Equation [6] we set g to zero, and assume that the decline rate and the discount are approximately the same. In that case, V = P/2.

However, that is only a broad generalization approximately true over a long period. As noted above, in-ground value is an index of price expectations. If the net prices are expected to rise in the future, the present value of a known deposit rises immediately. Therefore an increase in the ratio of V to P signals an expected rise in price. Rearranging Equation [6] we have:

$$g = i + a(1-(P/V)) \qquad [7]$$

We can make this calculation from the data in Table VII, and the annual production:reserve ratio in Table III, by assuming the real discount rate is 10 percent. It is shown in Figure 17.

[FIGURE 17 HERE]

We cannot claim accuracy for these estimates, since they are very sensitive to the discount rate. However, it is easy to substitute a better one; there is a one-to-one correspondence between changes in i and changes in g. It would raise or lower the curve, but not change its slope anywhere.

Figure 17 shows that the steep price increases of 1946 and 1947 were not expected to last; they did last, however. There was some mild pessimism in the early 1950s, which was reversed in 1955; the better tone lasted through the early 60s, but then became increasingly poor. Ever-worse price deterioration was expected through 1970. Here the apprehension was justified, since the real price kept dropping. But expectations grew less bad in 1971-72, and then became practically neutral in 1973. The poor expectations of 1974-79 indicated the industry did not expect to keep all of its gains, but it is interesting that when the price shot up in 1980-81, expectations were for further increases. But the turnaround in prices did not lead to bad price expectations. Interestingly, the price deterioration of 1985 improved g, and the 1986 collapse put it to an unprecedentally high level. In other words, the low 1986 price was expected to turn around, and this was a correct forecast.

[Beninger & Arndt 1987] list 47 sales of oil and/or gas properties between January 1986 and August 1987. Table VIII shows the results of four ordinary least squares regressions, with reserve values as determined by oil and gas reserves. Neither a constant nor a time trend makes economic sense because each is related to the total value of the property sold, hence a distortion of any non-average property. An R^2 of .98 indicates very high heteroscedasticity. To adjust for it, we divide each observation by the estiamted value of the property. In equation 4, the R^2 is now only 0.22. The per-barrel values are now $5.80 per barrel and 82 cents per Mcf, and even more highly significant. The estimated value per barrel is almost identical with the Herold value for 1986. Nevertheless, the average estimated value is 11 percent above the actual. Hence it is plausible that a better estimate would be $5.22 per barrel and 74 cents per Mcf. It is interesting how little the gas estimate is changed by the various estimating methods. The period was of course, a highly disturbed one, but we are unable to see any indications of this in the residuals pattern.

<u>Reserve Values in late 1987</u> [Salomon 1988] have tabulated sales of oil and gas reserves, of which 19 observations are usable, for the months July-November 1987. (See Table VIIIB.) Ordinary least squares regression, corrected for heteroscedasticity, estimates the value at $4.34 per barrel,

$0.74/Mcf. During this period, average market prices of oil and gas were respectively about $16 and $1.80. (The spot price of gas was lower, but the value of a developed reserve is determined by the contracts in force rather than those which might be newly made.) The oil value seems therefore to be on the low side, the gas value on the high side, of the traditional 1/3 rule.

CONCLUSIONS

"Exhaustible resources" Since the whole earth is finite, any mineral in it is finite, but we know not where the limits are, and it would not matter if we did. We will never get to the end of our oil resources. We will stop impounding them into reserves when it no longer pays.

To treat the total of "economic" resources, i. e. those worth producing, as a pre-fixed non-renewable stock, is circular reasoning, assuming the conclusion. For in order to estimate that amount we first need to estimate future costs and prices. We might as well claim that there was a pre-fixed number of buggy-whips to produce. In fact, the logistical curve is a good description of a manufacturing industry, every one of which has gone through a phase of accelerating then decelerating growth. [Burns 1934]

Cost increases would be a sonar "ping" warning us we were getting closer to the end, when it would no longer pay to find and develop. The ping did not get any louder during 1945-73. Development cost tended if anything to decrease, an indicator that discovery costs were not rising either. It roughly doubled after 1973, returning to the 1955-62 level. Much but by no means all of the increase is explained by the inefficiencies and waste imposed by a more than threefold investment expansion in only eight years.

We are left with a realization of how much reserves can keep expanding literally decades after all the big fields are found, and at no increase in real cost. That expansibility is now being sorely tried.

Meyer, Woods, and others have drawn attention to the estimates derived from discovery process models of very large numbers of very small fields, relatively easily found, and containing, in the aggregate, large amounts of oil. [Meyer and Fleming 1985, and sources cited there. Woods 1985, GRI 1985.] Smith and Paddock [1984] have been able to approximate discovery decline curves in various provinces. A small difference in the slope of the decline curve of field size makes a considerable difference in the total area to be added. And both the height and slope of the discovery curve depends on improved development technology, which improves finding rates, because more new fields are worth exploitation.

Cumulative depletion has its favorable side. Intensive drilling and production have produced a dense network of pipelines and infrastructure, which allows quick production, thereby lowering cost. One sees a similar development in places like the North Sea, where pipelines to shore were a major fraction of development cost, and remain to be used by newer smaller fields as the older larger ones go into decline. Moreover, development costs per drilling-production unit in 1000 feet of water have dropped about three-fourths in ten years. [Petrie and Wright 1985]

In Alaska, Prudhoe Bay had about 25 billion barrels in place, of which 10 billion became reserves. But overlaying Prudhoe Bay are the West Sak and Ugnu formations containing perhaps 70 billion barrels in place. [OGJ 1985b] If any of it is developed into reserves--none has been--it will certainly be much higher-cost oil than Prudhoe. On the other hand, the Kuparuk waterflood promises one billion barrels for $445 million, cheap in any league. [PIW 1985]

In mid-1987, a developed barrel of oil reserve in the ground appeared to be worth about $4.50, while its cost was about $3.00. On average, therefore, the industry is in no danger of disappearing, nor even of drastic shrinkage. But a considerable number of marginal deposits have lower value and higher cost, and will be scratched. Moreover, if the pure resource value is $1.50, one must question how much oil can be discovered at that cost or less. Without new fields and pools to freshen the mix, development costs must creep upward, though we cannot tell how fast.

The collapse and recovery of oil prices in 1986-87 begins a new chapter. For the first quarter of 1987, the number of rotary rigs operating averaged 825, about half of the 1975 level. But the number of wells completed, and footage, were about equal to 1975, while prices in the $15-$20 range compared with $5-$12, average $7.67. [DOE 1975]

Today, the better prospects look better than ever, at the expense of a lot of poor or mediocre ones. It is reasonable to expect a shrinking domestic industry at prices in the $15-$20 range, but we will hazard the guess that the decline will be quite slow. The forecasts of the National Petroleum Council and others [PIW October 1986], that production in and outside the United States will shrink even as prices rise, may turn out to be true, but as of now they have no foundation in fact.

APPENDIX: COST CALCULATIONS

The objective of the calculations is to obtain the marginal or incremental capital cost per barrel of oil or per mcf of gas by investing in a new project.

Define: P = market price <u>or</u> supply price (see below).

i = market interest rate

K = capital expenditures.

R = reserves to be developed.

Q = initial or peak output

a = exponential decline rate

T = life of project

Taking <u>i</u> the discount rate as exogenous, we calculate <u>P</u> as supply price or cost, the price at which the investment would be just barely worth making.

Derivations

1) Reserves are cumulative production, declining exponentially:

$$R = Q \int_0^T e^{-at}\, dt = Q * \frac{1-e^{-aT}}{a} \qquad [1]$$

For most values of a and T, the last expression converges quickly to unity, and may usually but not always be dropped.

2) For a given investment, the Net Present Value:

$$NPV = PQ \int_0^T e^{-(a+i)t} \, dt - K = 0 \qquad [3]$$

$$PQ * (1-e^{-(a+i)T}) = K * (a+i)$$

Substituting [1] into this equation, and transposing:

$$P = \frac{K}{R} * \frac{a+i}{a} * \frac{(1-e^{-aT})}{(1-e^{-(a+i)T})} \qquad [4]$$

For typical values of a, i, and T, the last fraction converges quickly to unity, and may usually but not always be dropped.

<u>or</u>, $P = (K/(Q/a)) * (a+i)/a = (K/Q)\ (a+i)$ [4a]

In words, the supply price is equal to the cost per unit in-ground (K/R) multiplied by the adjustment for holding the stock until produced, (a+i)/a = (1+ (i/a)); <u>or</u> to the investment per annual barrel multiplied by the compound discount rate.

Alternatively, if the price is known, we solve for the rate of return:

$$i = a*((PR/K)-1) \qquad [5]$$

<u>or</u>, $i = PQ/K - a$ [5a]

Where T is known, find <u>a</u> by solving equation [1], but using actual T instead of infinity. Then insert <u>a</u> and known T into Equations [4] or [5], and solve alternatively for <u>P</u> or <u>i</u>.

<u>Note</u>: In the foregoing, we assume all capital expenditures made at one time, in year zero. We assume peak output initially, then an exponential decline.

In fact, capital expenditures stretch over several years, usually peaking in or just before year zero, when production starts. Typically, production builds up over 2 - 3 years, then holds approximately stable for a few more, then declines steeply.

The errors are mutually offsetting. [Adelman & Paddock (1980)] showed that for North Sea fields, the value of P calculated as above gave an excellent prediction of the values as calculated from the actual production plans, tabulated by Wood McKenzie.

The result of the Adelman-Paddock test is not surprising. [McCray 1975] gives the following formula slightly adapted here for calculating the expected decline period, which our short method equates to infinity:

$$T = \frac{R}{Q_0 - Q_f} * \ln (Q_0 / Q_f)$$

where T is the period in years, R = reserves = estimated cumulative output, Q_0 = initial-year output, and Q_f = final-year output. Obviously when the final-year output is zero, the period is infinite.

If T is finite, a is less, and the extreme right-hand fraction of Equation [4] is less than unity. Hence the supply price is less, and the return is higher, than would result from our simpler use of the K/R * (a+i)/a approximation.

Consider proved reserves of 100, initial-year output of 10. On the usual assumptions of infinite life, the depletion/decline rate is taken at 10/100 = 0.1. Assume (K/R) = \$1, and the discount rate at 10 percent. Then by Equation [4], with the final right-hand fraction converging to unity:

$$P = \frac{K}{R} \frac{a+i}{a} = 1*2 = \$2 \qquad i = [Pa/(K/R)]-a$$

Alternatively: assuming that the market price P = \$3, i = 0.2.

Suppose we know, however, that final-year output is 2. then we calculate:

$$T = \frac{100}{10-2} * \ln 5 = 12.5 * 1.6 = 20.1 \text{ years}$$

If so, a decline rate of 8.0 percent per year yields cumulative output of 99.96, and P = \$1.85. Alternatively, if we assume a market price of \$3, then on the infinite-life assumption, the rate of return is 20 percent. Setting T = 20.1 and a = .08, the resulting i = 22 percent.

Thus our method, which assumes infinite time, understates present value, and overstates cost by a factor of 9.2 percent.

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[Shultz et al 1970] Cabinet Task Force on Oil Import Control [Secretary George P. Shultz], The Oil Import Question (Washington: February 1970)

[Smith & Paddock 1984] James L. Smith and James L. Paddock, "Regional Modelling of Oil Discovery and Production", Energy Economics, vol. 6, no. 1, January 1984, pp. 5 - 13

[Uhler & Eglington 1986] Russell S. Uhler, with the collaboration of Peter C. Eglington, The Potential Supply of Crude Oil and Natural Gas Reserves in the Alberta Basin (Ottawa: Economic Council of Canada 1986)

[WSJ 1985] Wall Street Journal, January 1,1985, p. 1

[Woods 1985] Thomas J. Woods, "Resource Depletion and Lower 48 Oil and Gas Discovery Rates", Oil & Gas Journal, October 28, 1985

FIGURE 1

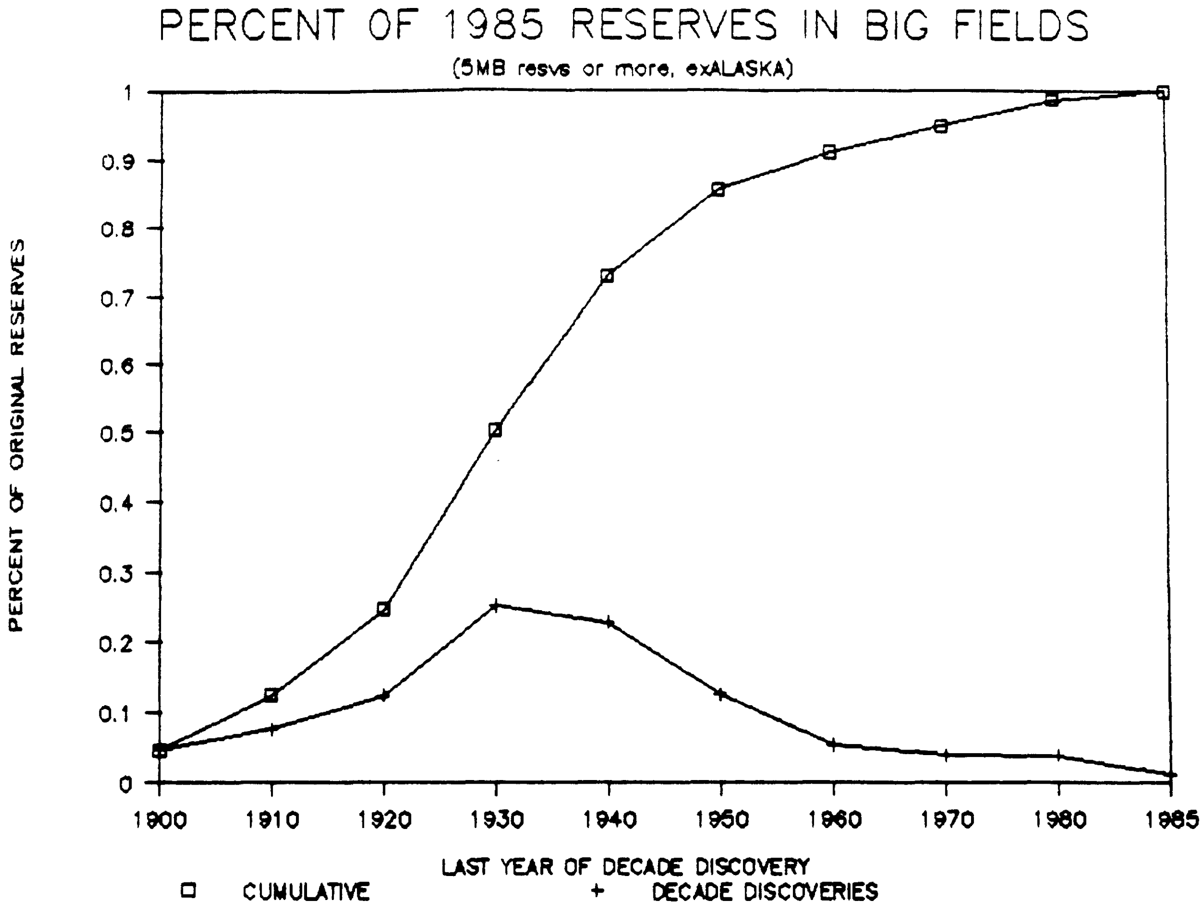

PERCENT OF 1985 RESERVES IN BIG FIELDS
(5MB resvs or more, exALASKA)
PERCENT OF ORIGINAL RESERVES
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
1900
1910
1920
1930
1940
1950
1960
1970
1980
1985
LAST YEAR OF DECADE DISCOVERY
CUMULATIVE
DECADE DISCOVERIES

FIGURE 2

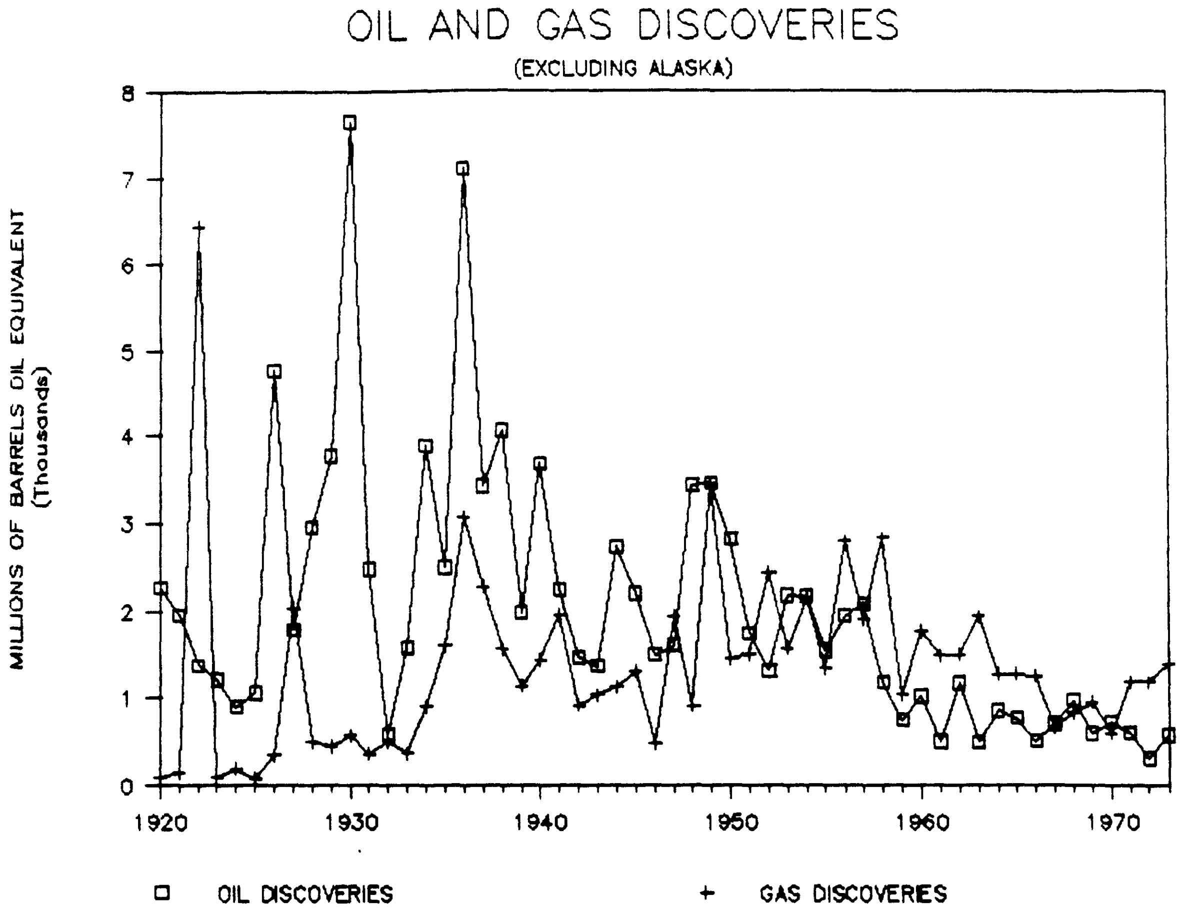

OIL AND GAS DISCOVERIES
(EXCLUDING ALASKA)
MILLIONS OF BARRELS OIL EQUIVALENT
(Thousands)
8
7
6
5
4
3
2
1
0
1920
1930
1940
1950
1960
1970
OIL DISCOVERIES
GAS DISCOVERIES

FIGURE 3

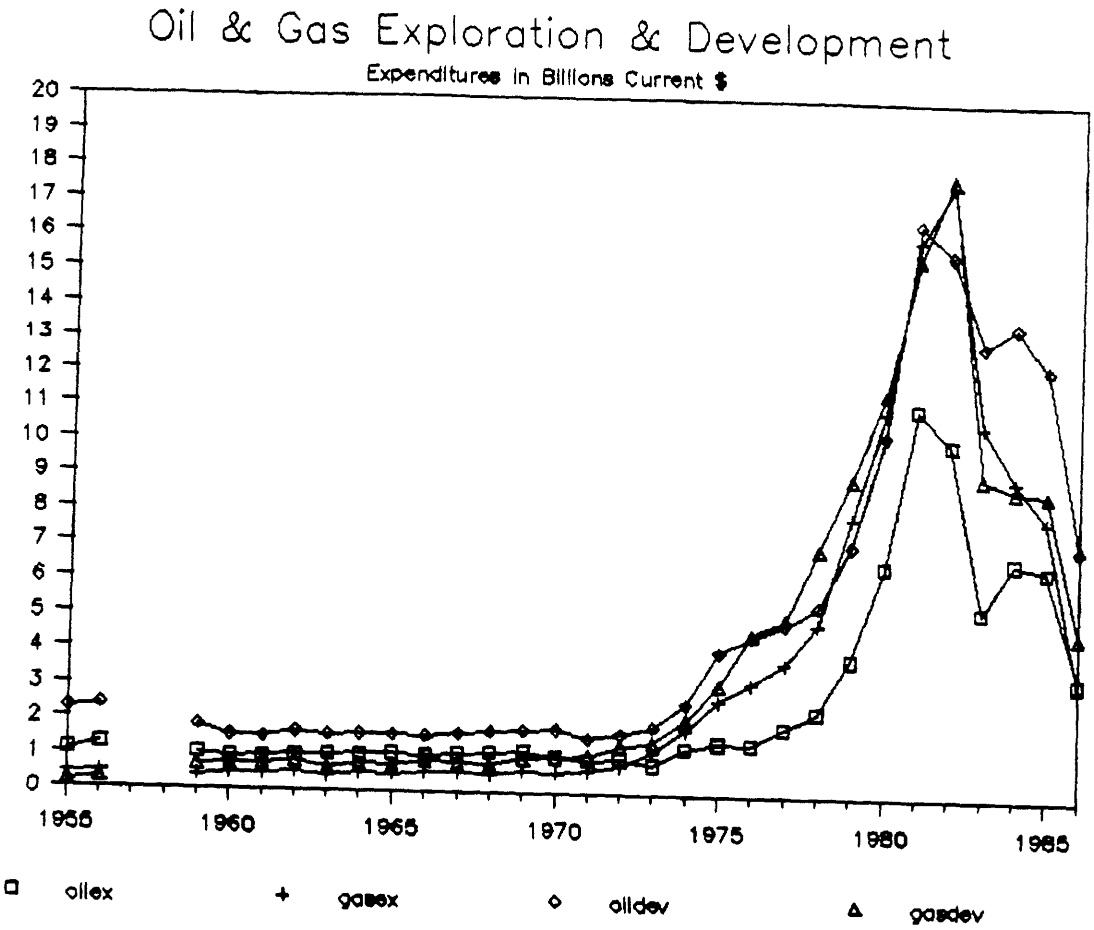

Oil & Gas Exploration & Development
Expenditures in Billions Current $
20
19
18
17
16
15
14
13
12
11
10
9
8
7
6
5
4
3
2
1
0
1956
1960
1965
1970
1975
1980
1985
oilex
gasex
oildev
gasdev

FIGURE 4

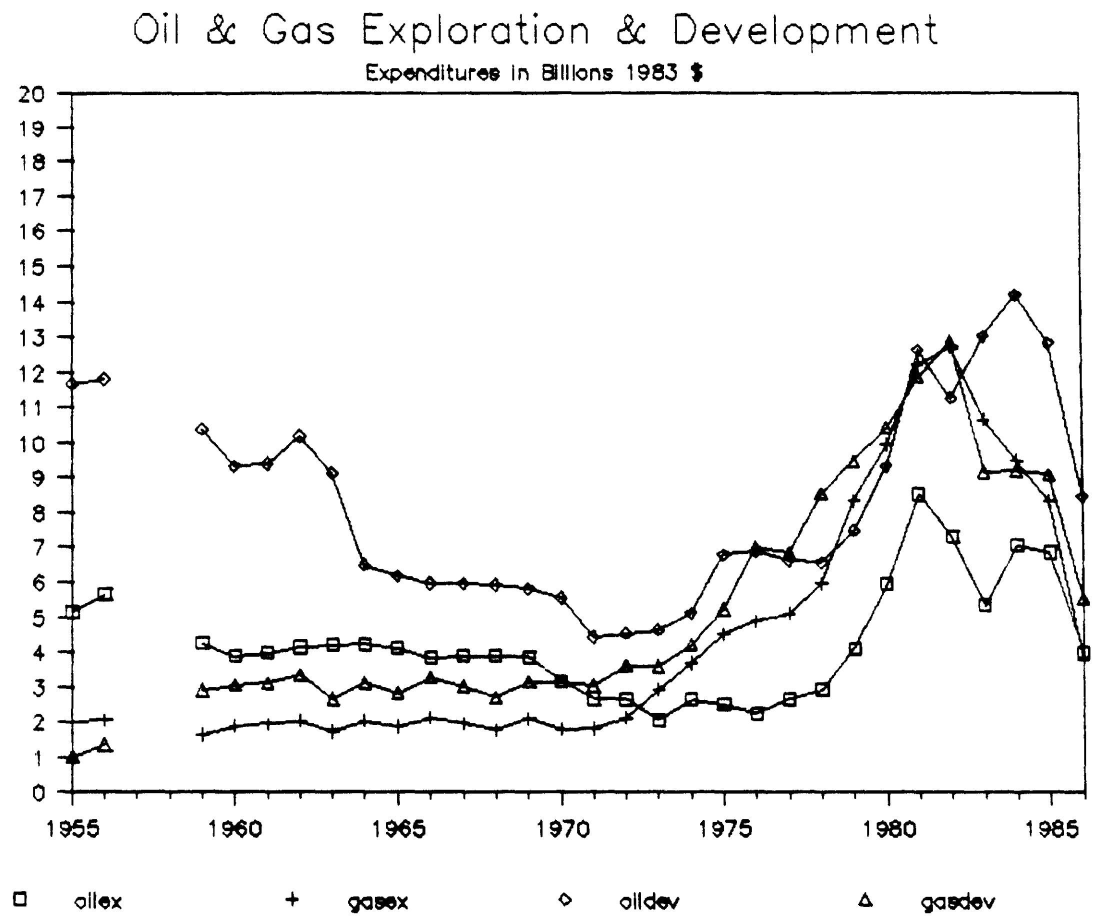

Oil & Gas Exploration & Development
Expenditures in Billions 1983 $
20
19
18
17
16
15
14
13
12
11
10
9
8
7
6
5
4
3
2
1
0
1955
1960
1965
1970
1975
1980
1985
oilex
gasex
oildev
gasdev

FIGURE 5

SUPPLY CURVES:INCREASING SCARCITY

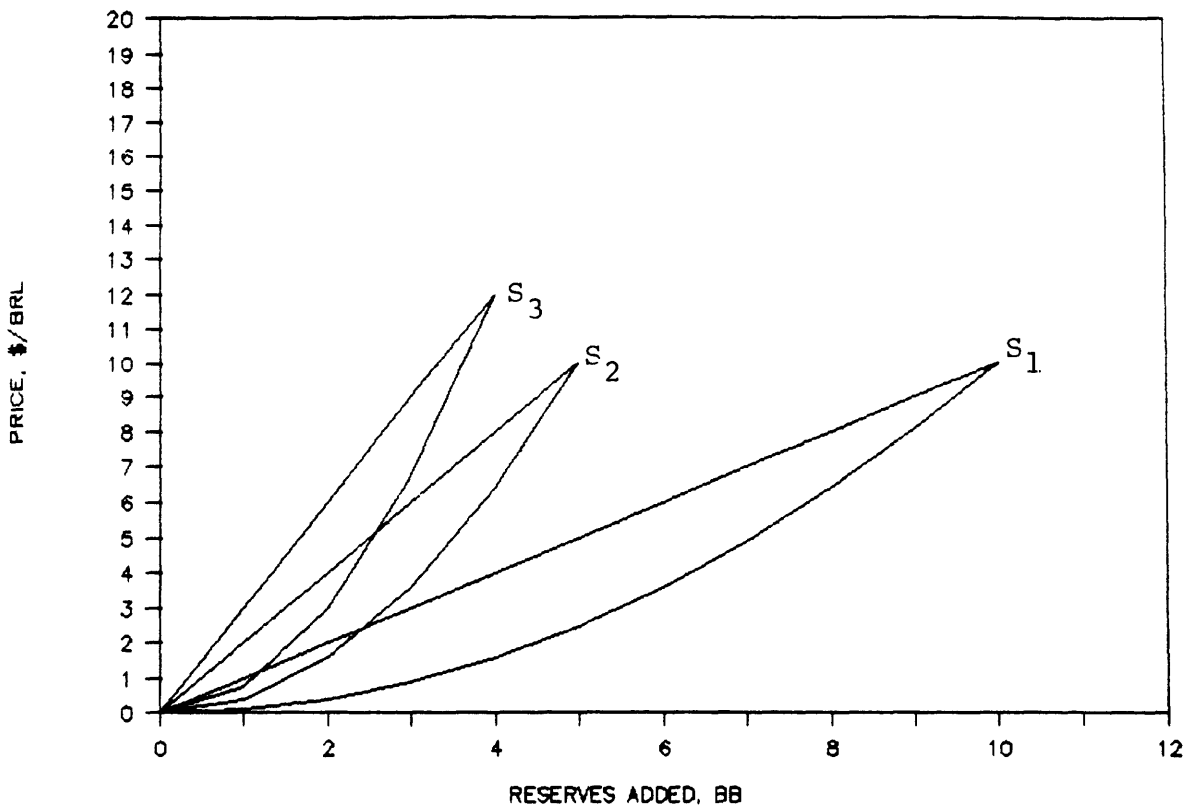


FIGURE 6

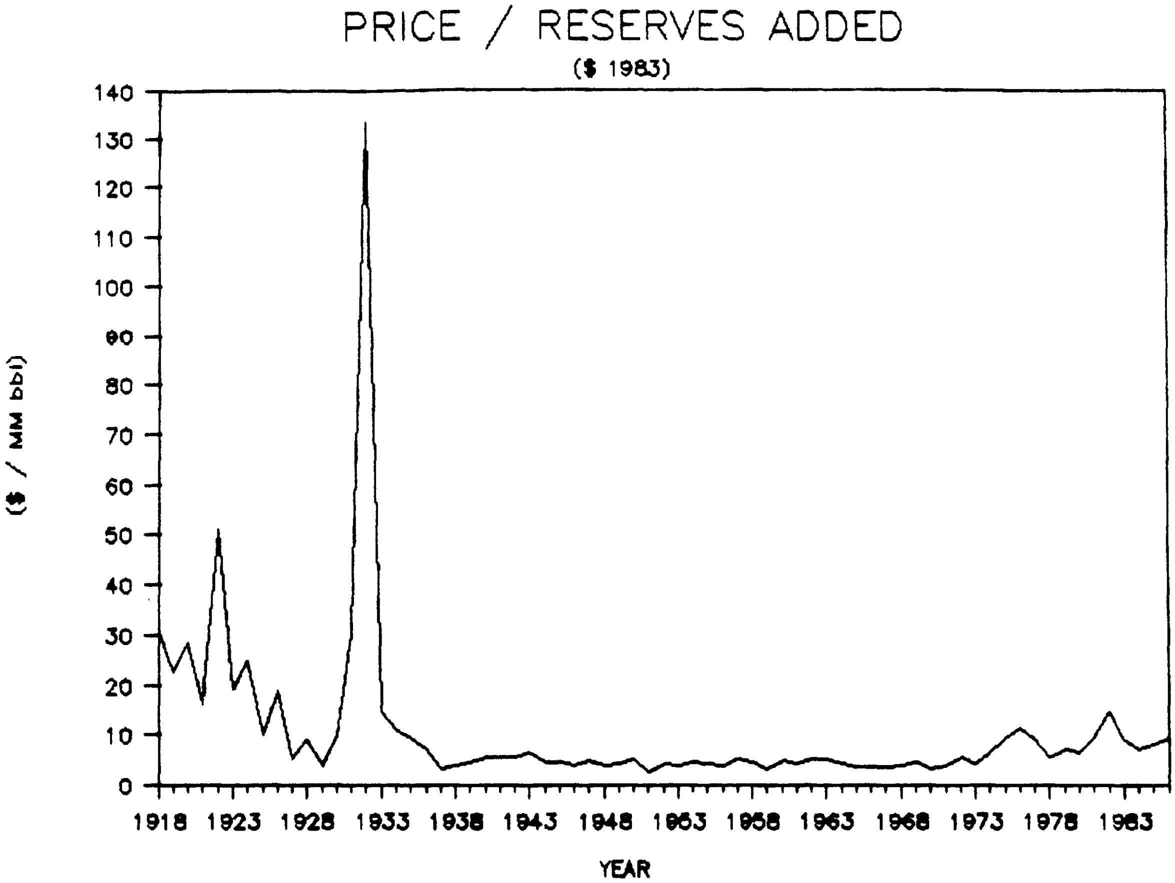
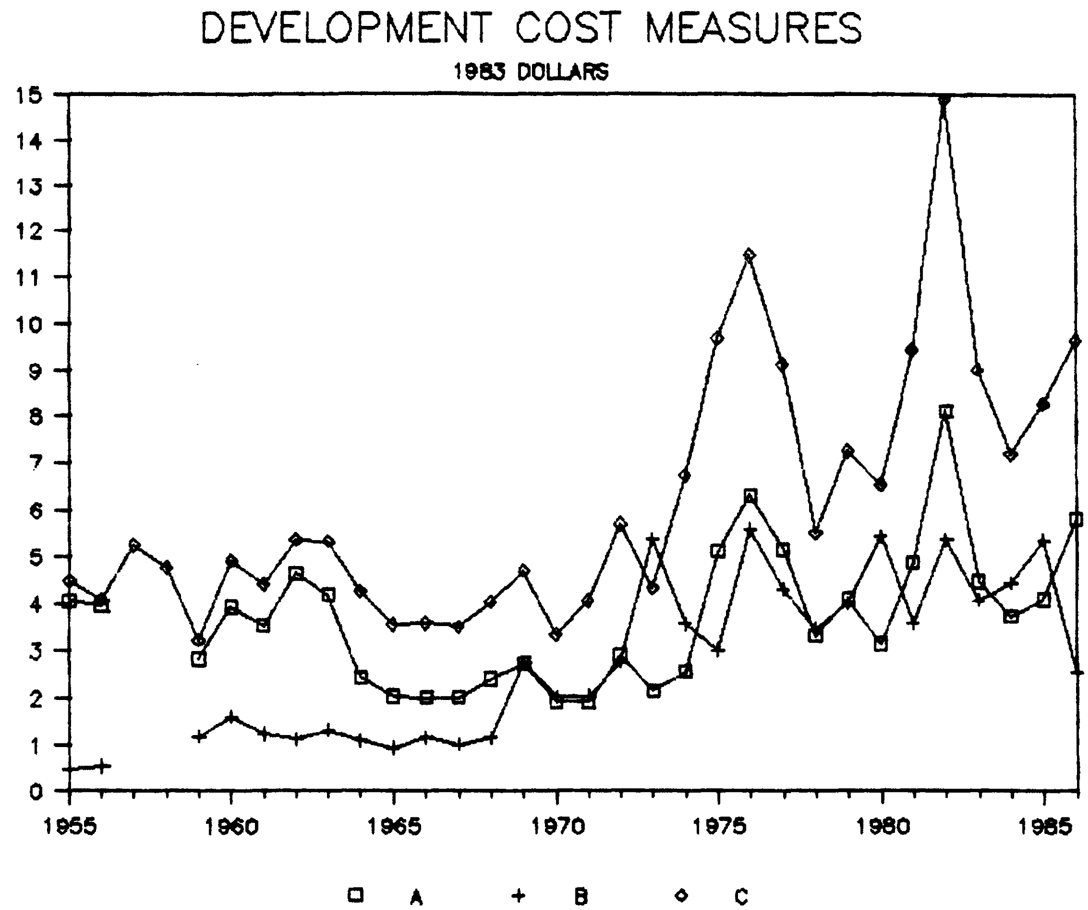

PRICE / RESERVES ADDED
($ 1983)
($ / MM bbl)
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0
1918
1923
1928
1933
1938
1943
1948
1953
1958
1963
1968
1973
1978
1983
YEAR

FIGURE 7



A = Development Cost per Barrel of Oil
B = 6*Development Cost per Mcf of Natural Gas*
C = Oil Price per Billion Barrels of Reserves Added

*In this graph, the unit cost of gas has been multiplied by a factor of 6 to allow comparison. No "oil equivalent" is intended.

FIGURE 8

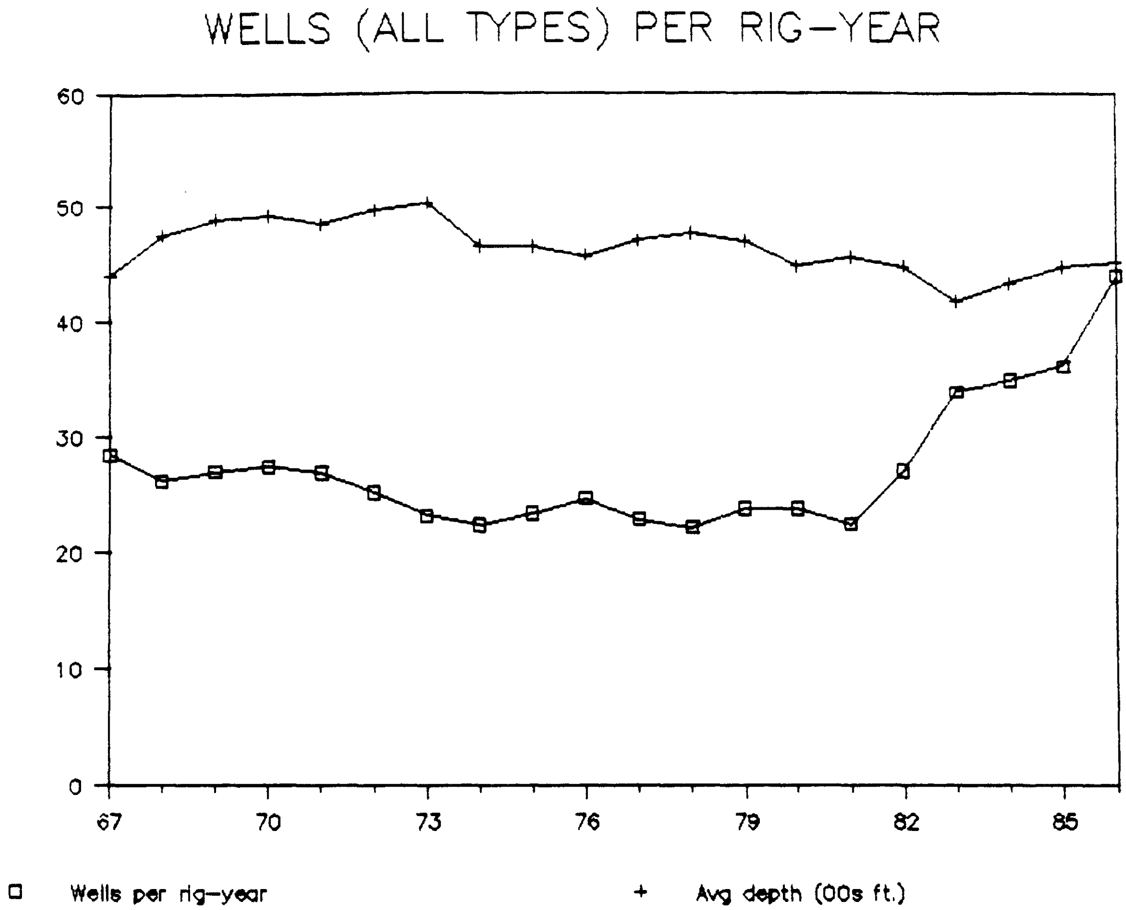
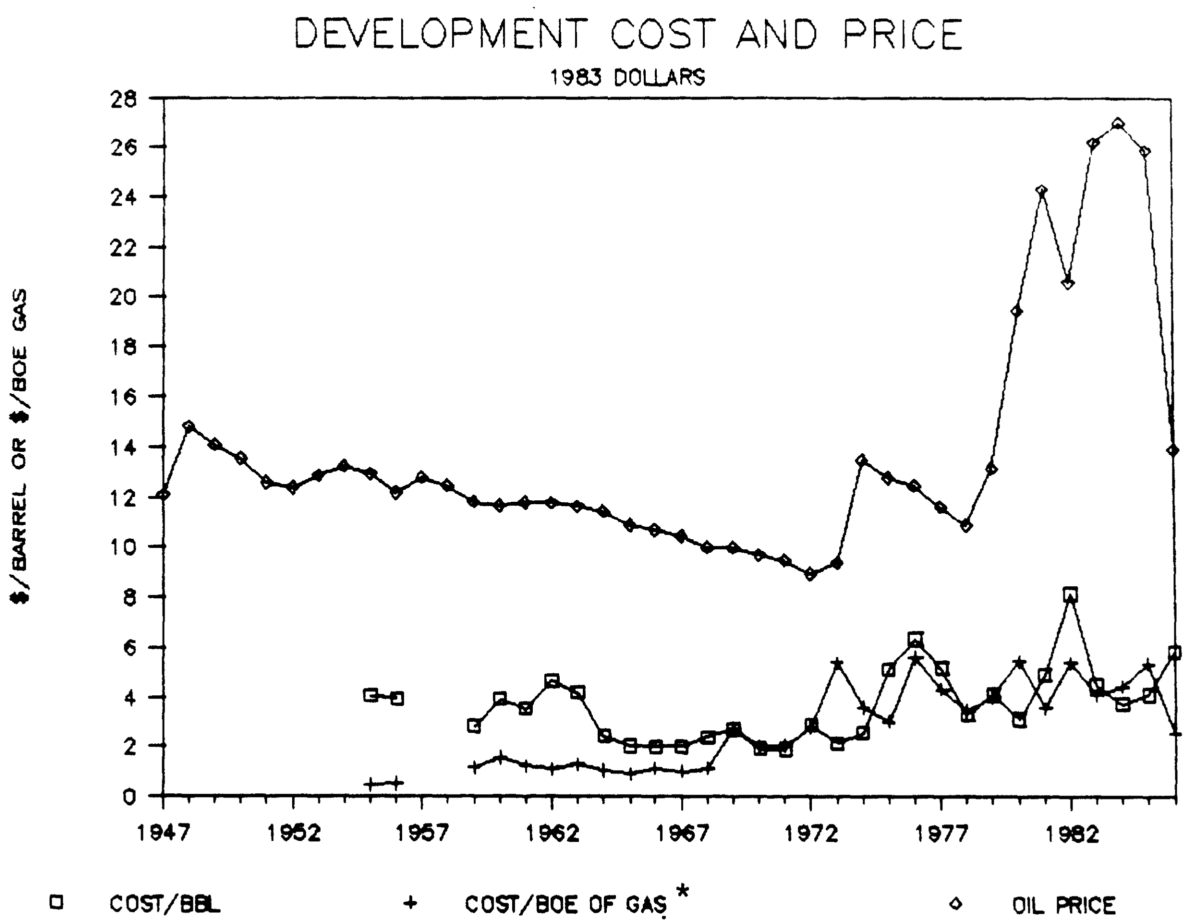
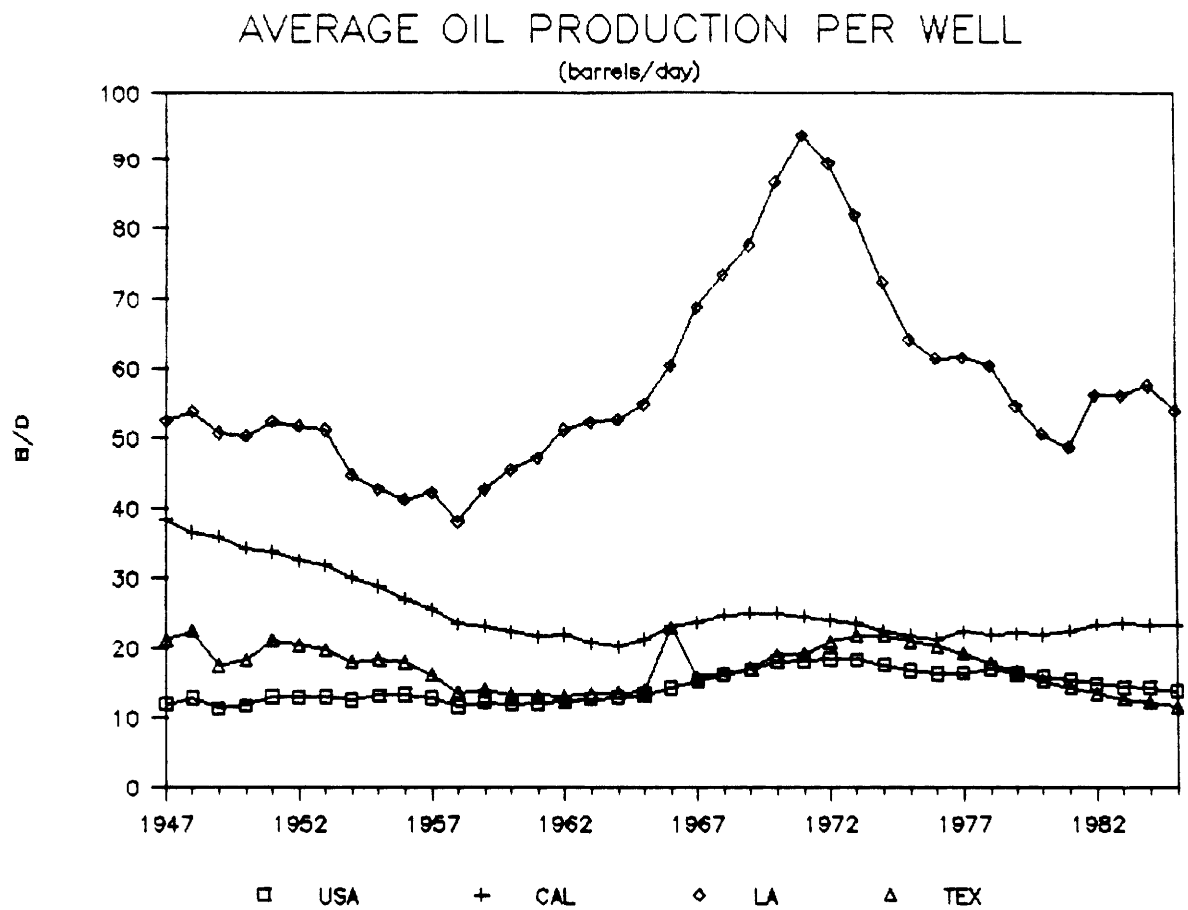

WELLS (ALL TYPES) PER RIG-YEAR
60
50
40
30
20
10
0
67
70
73
76
79
82
85
Wells per rig-year
Avg depth (00s ft.)

FIGURE 9



*See note at Figure 7.

FIGURE 10



AVERAGE OIL PRODUCTION PER WELL
(barrels/day)
B/D
100
90
80
70
60
50
40
30
20
10
0
1947
1952
1957
1962
1967
1972
1977
1982
USA
CAL
LA
TEX

FIGURE 11

AVERAGE GAS PRODUCTION PER WELL

(MCF/DAY)

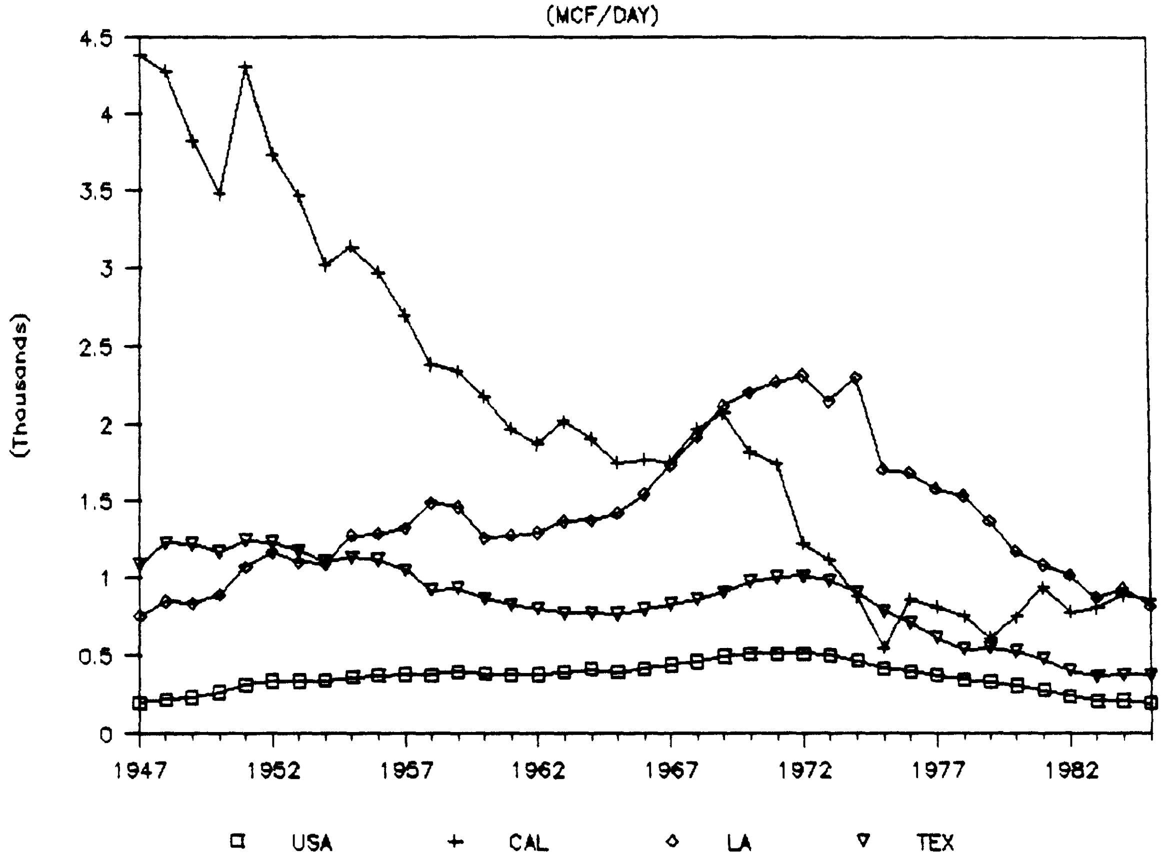


FIGURE 12

CRUDE OIL: PRICE, IN-GROUND VALUE, COST

USA 1946-1987

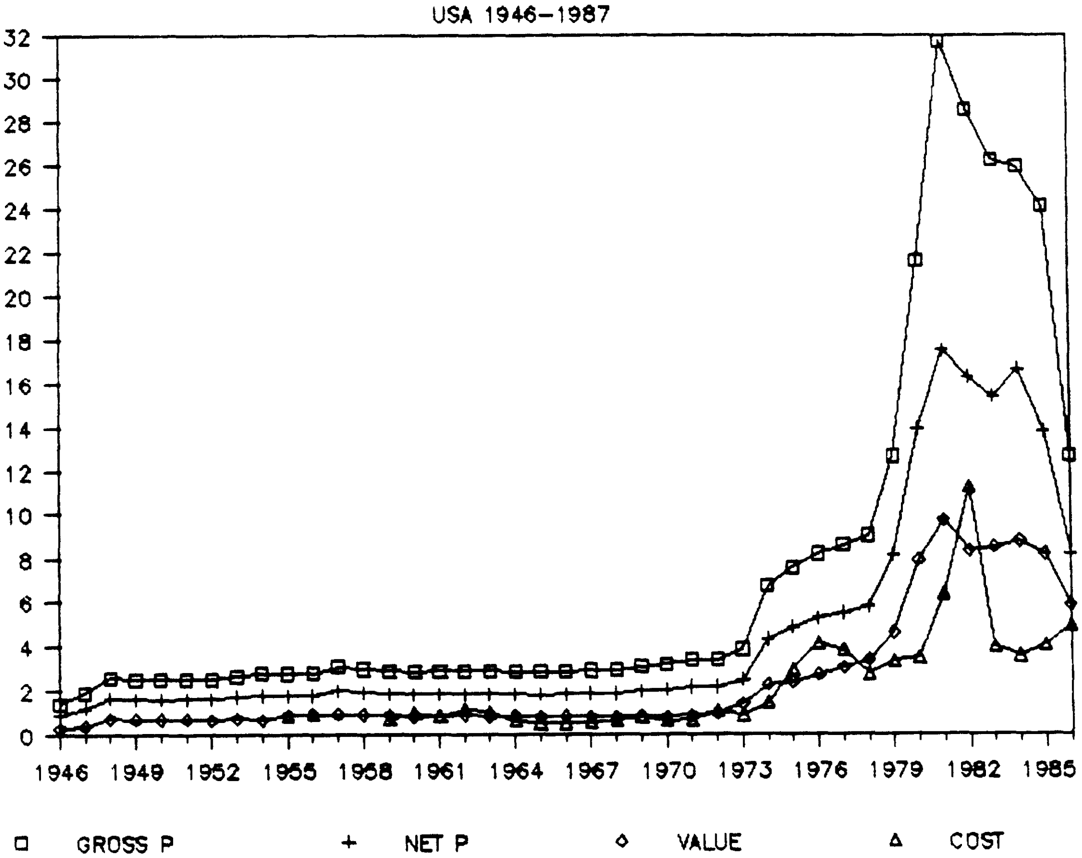
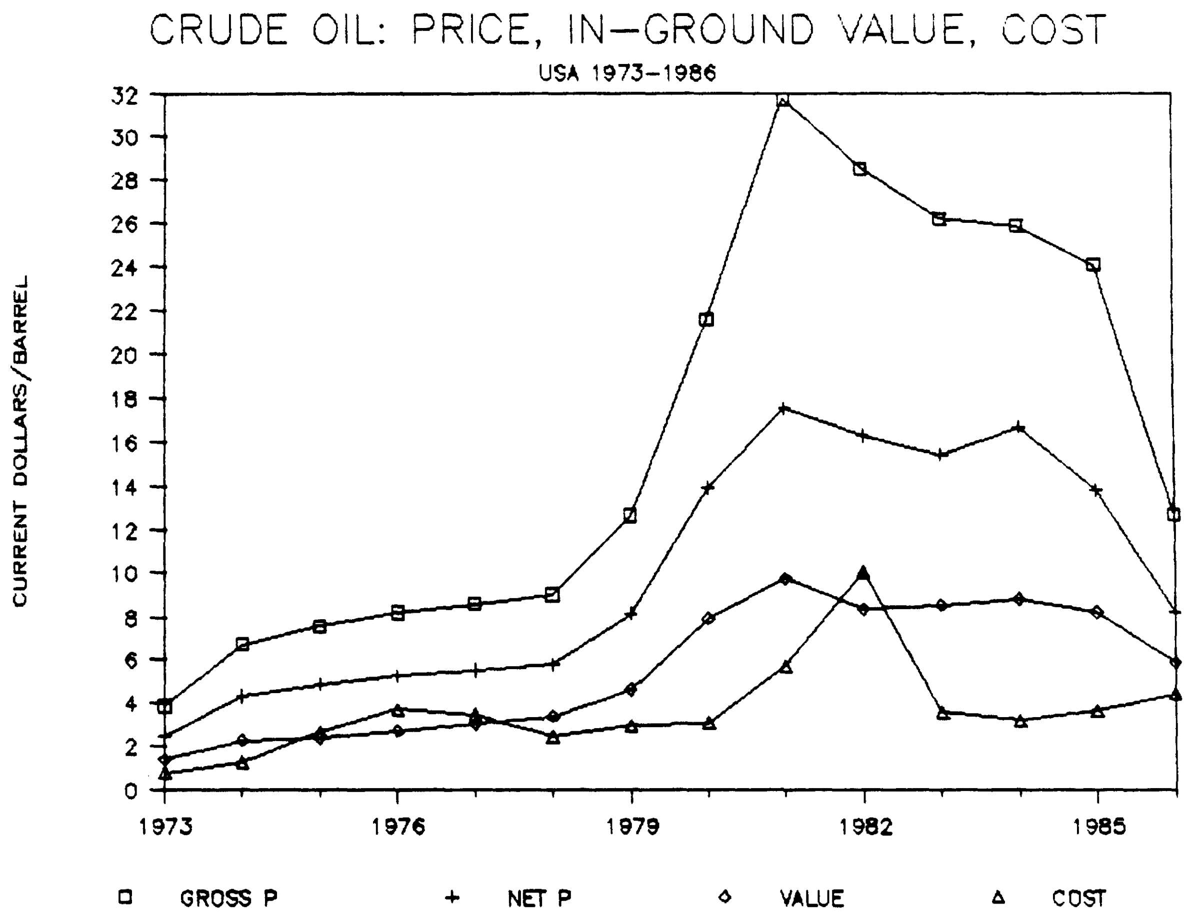


FIGURE 13



CRUDE OIL: PRICE, IN-GROUND VALUE, COST
USA 1973-1986
CURRENT DOLLARS/BARREL
32
30
28
26
24
22
20
18
16
14
12
10
8
6
4
2
0
1973
1976
1979
1982
1985
GROSS P
NET P
VALUE
COST

FIGURE 14

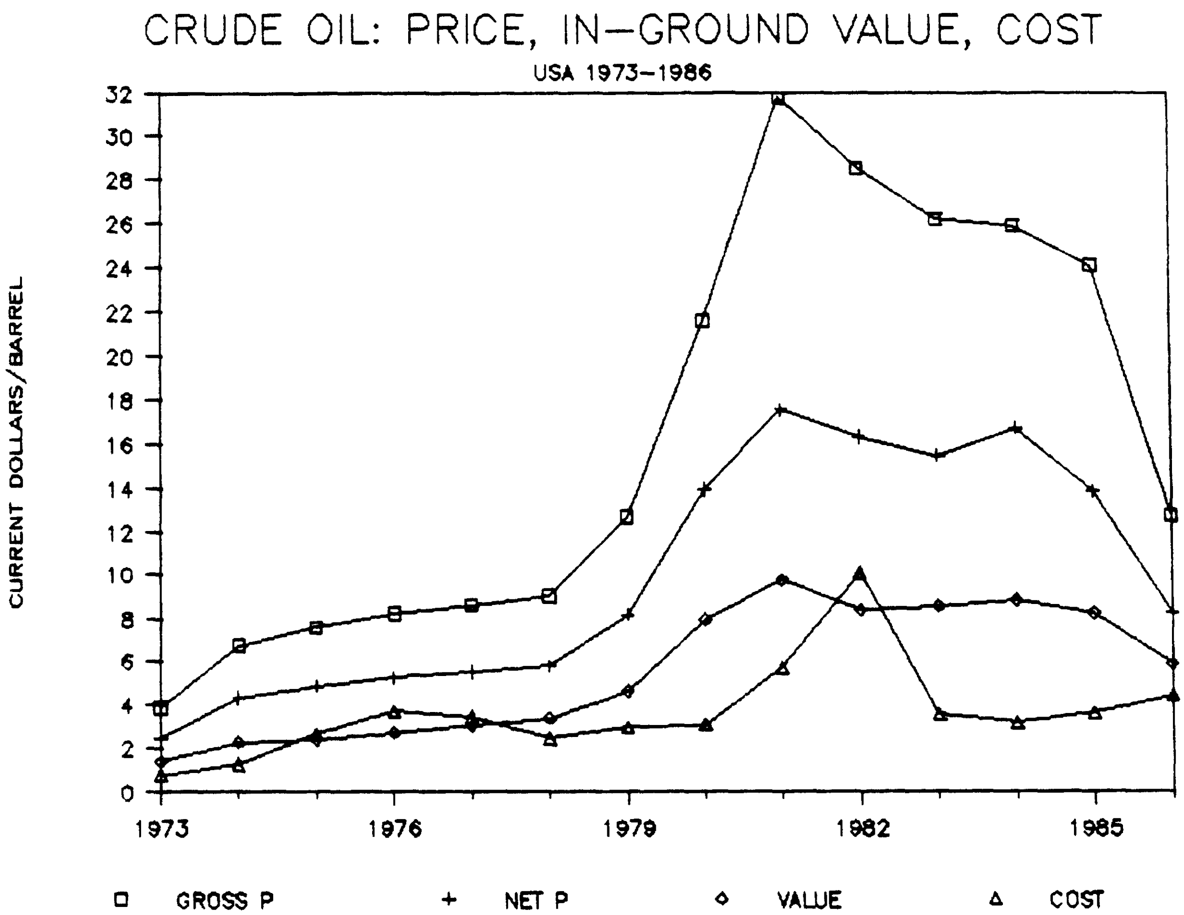
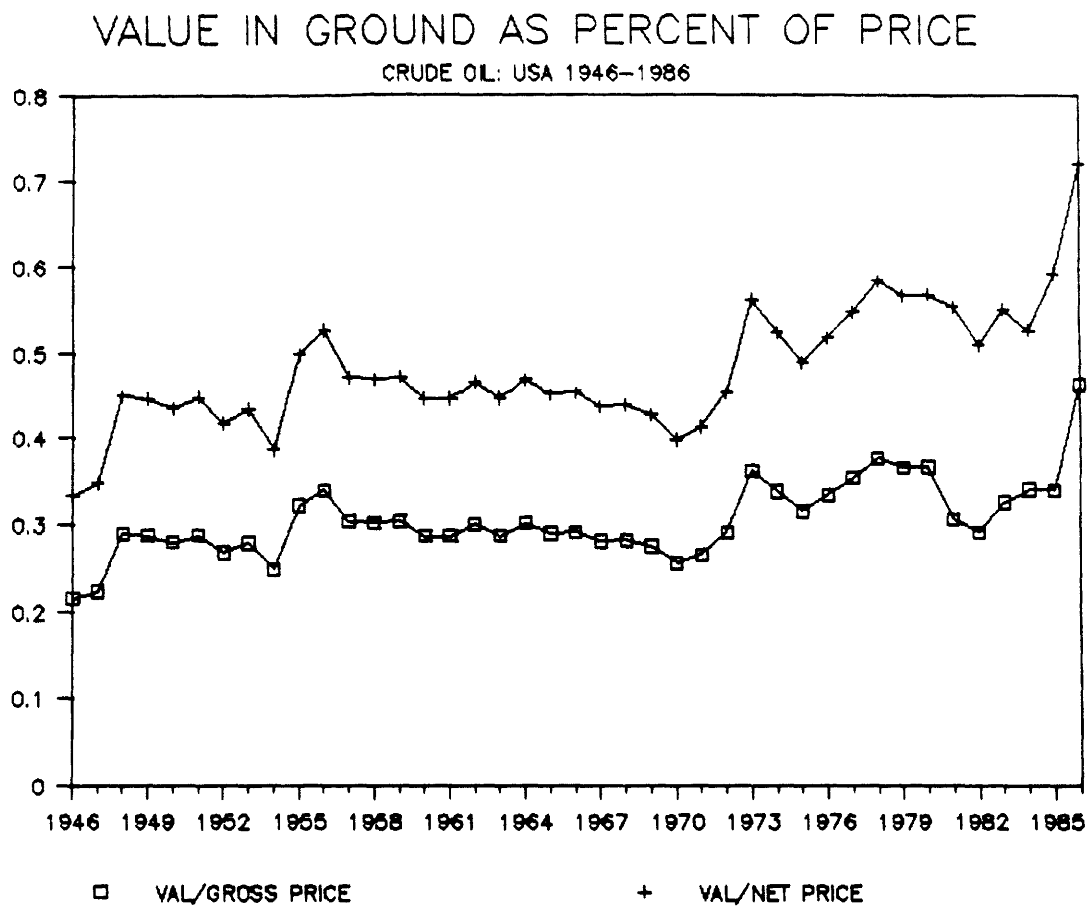

CRUDE OIL: PRICE, IN-GROUND VALUE, COST
USA 1973-1986
CURRENT DOLLARS/BARREL
0
2
4
6
8
10
12
14
16
18
20
22
24
26
28
30
32
1973
1976
1979
1982
1985
GROSS P
NET P
VALUE
COST

FIGURE 15



VALUE IN GROUND AS PERCENT OF PRICE
CRUDE OIL: USA 1946-1986
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
1946
1949
1952
1955
1958
1961
1964
1967
1970
1973
1976
1979
1982
1985
VAL/GROSS PRICE
VAL/NET PRICE

FIGURE 16

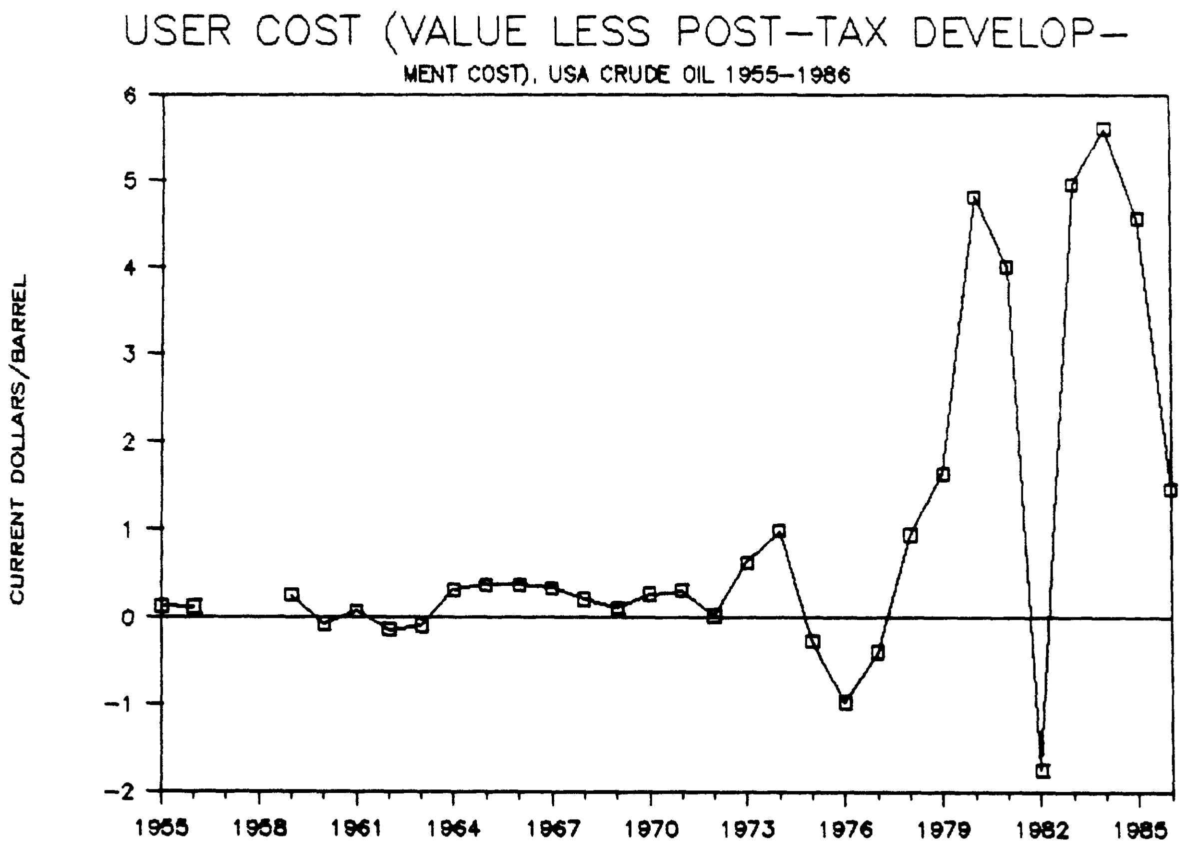
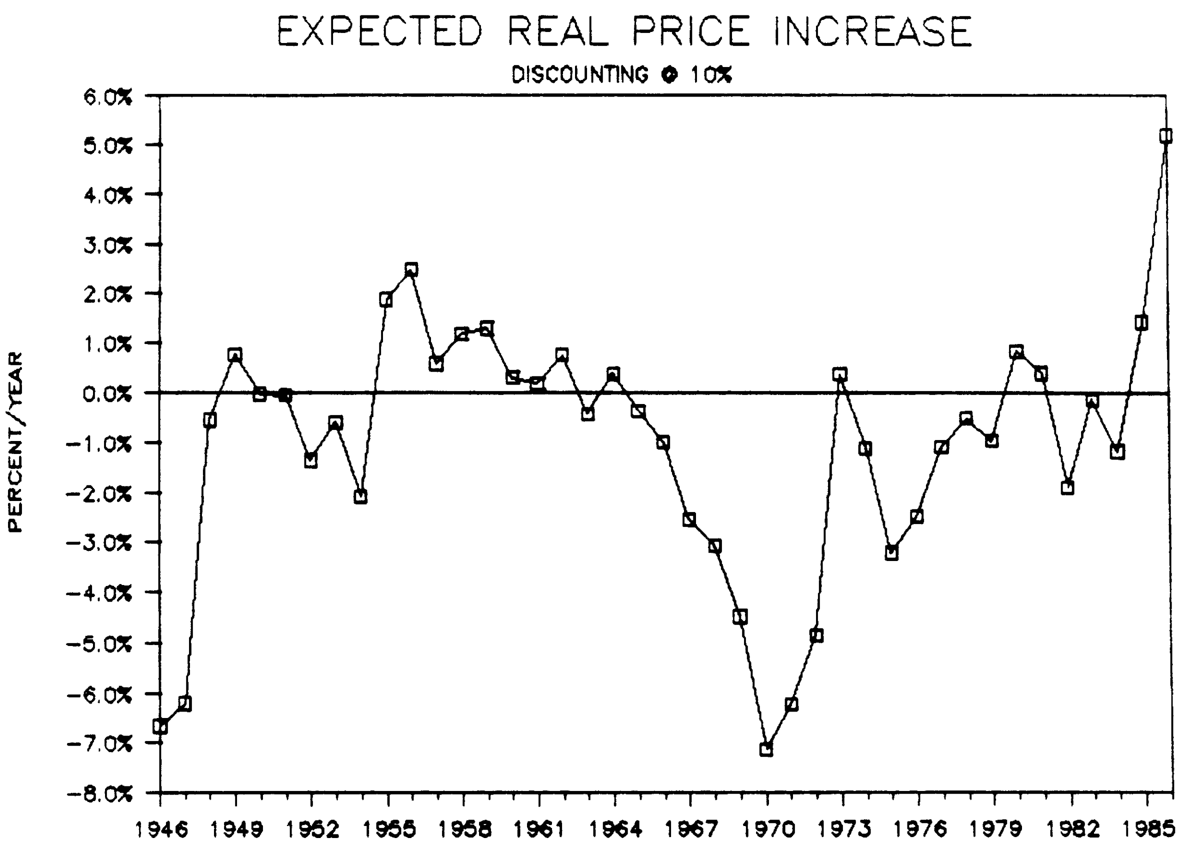

USER COST (VALUE LESS POST-TAX DEVELOP-
MENT COST), USA CRUDE OIL 1955-1986
CURRENT DOLLARS/BARREL
6
5
4
3
2
1
0
-1
-2
1955
1958
1961
1964
1967
1970
1973
1976
1979
1982
1985

FIGURE 17



EXPECTED REAL PRICE INCREASE
DISCOUNTING @ 10%
PERCENT/YEAR
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
-1.0%
-2.0%
-3.0%
-4.0%
-5.0%
-6.0%
-7.0%
-8.0%
1946
1949
1952
1955
1958
1961
1964
1967
1970
1973
1976
1979
1982
1985

TABLE I

DISCOVERY AND DEVELOPMENT EXPENDITURES 1955-1986
(In millions 1983 dollars)

		Exploration			Development		
	1	2	3	4	5	6	7
Year	Drilling Cost Index (1983=100)	Total	Crude Oil	Non-associated Gas	Total	Crude Oil	Non-associated Gas
1955	21.4	7150	5141	2009	12677	11679	997
1956	22.9	7695	5647	2048	13160	11796	1364
1957	24.2	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
1958	24.2	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
1959	24.6	5888	4250	1638	13265	10378	2887
1960	24.7	5762	3878	1885	12371	9322	3049
1961	24.5	5924	3965	1959	12493	9389	3105
1962	24.7	6175	4144	2031	13531	10182	3349
1963	24.9	5936	4202	1734	11785	9120	2664
1964	25.2	6246	4221	2025	9595	6484	3111
1965	26.3	5984	4111	1873	9000	6184	2817
1966	27.0	5942	3832	2110	9230	5952	3278
1967	28.0	5825	3872	1954	8947	5947	3000
1968	29.5	5649	3886	1763	8591	5910	2681
1969	30.9	5936	3848	2088	8948	5801	3147
1970	32.8	4946	3155	1792	8684	5538	3146
1971	35.8	4491	2665	1825	7459	4427	3032
1972	38.0	4756	2645	2111	8136	4525	3611
1973	41.7	4946	2047	2899	8214	4629	3585
1974	51.0	6319	2628	3691	9303	5101	4202
1975	60.1	6991	2499	4492	11993	6781	5212
1976	65.9	7105	2235	4870	13847	6869	6978
1977	73.8	7729	2640	5089	13410	6592	6817
1978	82.8	8843	2910	5932	15059	6535	8524
1979	96.0	12375	4076	8299	16918	7453	9465
1980	110.9	15868	5923	9944	19744	9329	10415
1981	130.8	20739	8502	12237	24473	12621	11852
1982	138.5	20004	7296	12707	24133	11263	12870
1983	100.0	15988	5325	10659	22205	13043	9154
1984	95.9	16518	7034	9484	23384	14191	9193
1985	95.9	15142	6832	8310	21963	12854	9099
1986	84.9	7744	3987	3757	13964	8453	5511

SOURCES: Table I

Column 1, Drilling cost index:

1955-62: Adjustment of 1963 index (see below) using Gross National Product Implicit Price Deflator, total for Gross Private Domestic Investment Non-Residential. The implicit price deflator and the drilling cost index correlate closely for 1963-72.

1963-85: Independent Petroleum Association of America, Report of Cost Study Committee, twice annually. Cost index refers to drilling and equipping wells.

1986: IPAA, change in judgemental index from May 1987 Report of the Cost Study Committee.

Column 2-8 Expenditures: see detailed calculation notes below

sources: 1955-72: Joint Association Survey
1973-82: Annual Survey of Oil and Gas, Bureau of the Census
1983-86: see below

Calculations:

Column 2 Exploration Total:

1955-72: (total exploration expenditures) - (lease acquisition + lease rental) + exploration overhead

1973-82: ((total exploration expenditures) - (lease acquisition + lease rental)) * ((gross expenditures drilling and equipping exploration wells) / (net expenditures drilling and equipping exploration wells))

1983-86: prior year's total exploration * percent change in total exploratory drilling (JAS)

Column 3 Exploration Oil:

1955-56: (column 2) * (# oil wells (development + exploration) / ((# oil + gas wells (development + exploration))

1959-72: (column 2) * (total oil expenditures (exploration and production) / (total oil + gas expenditures (exploration and development))

1973-82: (column 2) * (gross expenditure drilling and equipping exploration oil wells) / (gross expenditure drilling and equipping exploration oil + gas wells)

1983-86: column 2 * percent of oil exploration drilling in total exploration drilling (JAS)

Column 4 Exploration Nonassociated Gas:

column 2 - column 3

Column 5 Development Total:

1955-72: (total development expenditures) + ((development + production overhead) * (total development expenditures) / (total development + production expenditures))

1973-82: ((total development expenditures) - (development acquisitions)) * ((gross expenditures drilling and equipping development wells) / (net expenditures drilling and equipping development wells))

1983-86: prior year's total development * percent change in development drilling (JAS)

SOURCES: Table I (continued)

Column 6 Development Oil:

1955-56: (column 5) * (# oil wells (development + exploration) /
((# oil + gas wells (development + exploration)

1959-72: (column 5) * (total oil expenditures (exploration and production) / (total oil + gas expenditures (exploration and development))

1973-82: (column 5) * (gross expenditure drilling and equipping development oil wells) / (gross expenditure drilling and equipping development oil + gas wells)

1983-86: prior year's oil development * percent change in oil development drilling

Column 7 Development Nonassociated Gas:

column 5 - column 6

TABLE II
RESERVES AND UNIT COSTS

	1	2	3	4
	RESERVES ADDED		(col 6 table I/ col 1) UNIT COSTS (1983 DOLLARS)	(col 7 table I/ col 2)
Year	Crude Oil (millions barrels)	Natural Gas Non-associated (bcf)	Crude Oil ($/bbl)	Natural Gas Non-associated ($/Mcf)
1947	2465	6464	n.a.	n.a.
1948	3795	7483	n.a.	n.a.
1949	3188	6845	n.a.	n.a.
1950	2563	9059	n.a.	n.a.
1951	4414	8475	n.a.	n.a.
1952	2749	9615	n.a.	n.a.
1953	3296	15363	n.a.	n.a.
1954	2873	5627	n.a.	n.a.
1955	2871	12748	4.07	0.08
1956	2974	15297	3.97	0.09
1957	2425	16205	n.a.	n.a.
1958	2608	17382	n.a.	n.a.
1959	3667	14782	2.83	0.20
1960	2365	11545	3.94	0.26
1961	2658	15147	3.53	0.20
1962	2181	18017	4.67	0.19
1963	2174	12256	4.20	0.22
1964	2665	17366	2.43	0.18
1965	3048	18431	2.03	0.15
1966	2964	17037	2.01	0.19
1967	2962	17964	2.01	0.17
1968	2455	13979	2.41	0.19
1969	2120	6855	2.74	0.46
1970	2890	9340	1.92	0.34
1971	2318	8917	1.91	0.34
1972	1558	7812	2.90	0.46
1973	2146	3988	2.16	0.90
1974	1994	7037	2.56	0.60
1975	1318	10371	5.14	0.50
1976	1085	7460	6.33	0.94
1977	1272	9451	5.18	0.72
1978	1965	14774	3.33	0.58
1979	1808	14069	4.12	0.67
1980	2970	11434	3.14	0.91
1981	2570	19877	4.91	0.60
1982	1382	14328	8.15	0.90
1983	2897	13415	4.50	0.68
1984	3748	12508	3.75	0.75
1985	3022	9593	4.12	0.90
1986	1446	12895	5.85	0.43

SOURCES: Table II

Column 1,2, Reserve additions by Development

Oil: 1946-76: API/AGA op. cit. Table II adjusted for Alaska (1970) using Table III-2.

1977-79: average of API/AGA data and Energy Information Administration Annual U.S. ... Reserves.

1980-86: EIA figures.

Gas: 1945-59: Adelman, The Supply and Price of Natural Gas (Oxford: Basil Blackwell, 1962) Table IV-B.

1960-65: Adelman methodology, see above.

1966-77: API/AGA op. cit. Table VIII.

1978-79: average of API/AGA and EIA figures.

1980-86: EIA op. cit.

Note: tables referenced are from sources given.

Note on Alaskan exclusion: Oil: only reserves discovered in 1968 and developed in 1970 were excluded. Gas: backdated discoveries include associated and nonassociated gas; therefore, Alaska excluded in 1968. Developed reserve additions include only nonassociated gas; therefore, no Alaskan exclusion made as nonassociated volumes are insignificant.

TABLE III
FACTORS BEARING ON COST CHANGES

	1	2	3	4	5	6	7
	Production/reserves (ex-Alaska) percent		Cumulative Production (ex-Alaska)		Development Wells Drilled		
Years	Crude Oil	Non-associated Gas	Crude Oil (millions bbls)	Non-associated Gas (000s boe)	Crude Oil (000s)	Gas (000s)	Total Drilling Expenditures Per Rig Year (1983 constant $)
1947	8.61	2.63	35024	2152	17.02	2.91	n.a.
1948	8.60	3.11	37026	2791	21.49	2.53	n.a.
1949	7.38	3.27	38845	3478	20.64	2.46	n.a.
1950	7.69	3.48	40789	4237	22.85	2.41	n.a.
1951	8.06	3.99	43003	5125	21.69	2.58	n.a.
1952	8.07	4.17	45260	6083	21.69	2.70	n.a.
1953	7.99	4.19	47572	7108	23.78	3.11	n.a.
1954	7.64	4.38	49829	8175	27.79	3.25	n.a.
1955	8.06	4.45	52248	9303	29.33	2.74	7.38
1956	8.39	4.57	54800	10523	28.46	3.72	8.18
1957	8.45	4.61	57359	11817	26.07	3.76	n.a.
1958	7.77	4.49	59731	13150	22.83	3.98	n.a.
1959	7.83	4.60	62214	14562	24.10	4.12	8.89
1960	7.82	5.05	64684	16130	19.86	4.39	10.68
1961	7.91	5.10	67190	17753	19.94	4.85	10.46
1962	8.11	5.02	69730	19413	20.04	5.08	12.04
1963	8.36	5.41	72312	21214	18.97	4.09	11.81
1964	8.52	5.58	74945	23125	19.40	4.28	10.83
1965	8.58	5.79	77620	25164	17.82	4.21	10.80
1966	9.15	6.02	80470	27319	15.42	3.59	11.83
1967	9.71	6.25	83479	29592	14.34	3.13	13.03
1968	10.08	6.82	86537	32049	13.38	2.97	12.18
1969	10.69	7.72	89658	34711	13.28	3.47	12.47
1970	11.22	8.59	92894	37563	12.28	3.35	13.31
1971	11.37	8.93	96072	40407	11.24	3.51	12.24
1972	12.22	9.77	99280	43356	10.75	4.83	11.65
1973	12.36	10.67	102393	46325	9.60	5.90	11.04
1974	12.30	10.90	105365	49173	12.79	5.96	11.38
1975	12.44	10.44	108181	51803	15.99	6.91	11.21
1976	13.06	10.91	110943	54404	16.60	8.08	12.65
1977	12.39	10.98	113638	56957	17.52	10.56	10.69
1978	12.56	11.14	116183	59531	17.88	12.62	10.63
1979	12.52	11.98	118628	62257	19.35	13.25	11.89
1980	11.32	11.43	121012	64912	30.34	15.05	12.24
1981	11.15	11.19	123369	67589	39.86	17.22	11.39
1982	11.36	10.39	125692	70065	35.61	16.24	14.21
1983	11.53	9.09	128047	72238	33.68	12.33	17.13
1984	11.49	10.14	130446	74626	37.06	13.83	16.43
1985	11.29	9.40	132831	76816	35.02	11.74	18.78
1986	11.13	9.21	135134	78946	18.67	7.65	22.38

SOURCES: Table III

Column 1,2 production / reserves

Oil: total U.S.: 1947-76: API/AGA, op. cit. Table II
1977-79: average of API/AGA and EIA figures.
1980-84 EIA op. cit.

Alaska: 1947-58: n.a. volumes are insignificant
1959-76: API/AGA, op. cit. Table III-2
1977-79: average of API/AGA and EIA figures.
1980-86 EIA op. cit.

Non-associated gas:

total U.S.: 1947-59: Adelman, The supply and Price of Natural Gas, op. cit. Table IV-B.
1960-65: Adelman methodology; see above.
1966-76: API/AGA, op. cit. Table VIII.
1977-79: average of API/AGA and EIA op. cit. figures.
1980-86 EIA op. cit.

Alaska:

reserves: 1947-58: n.a., volumes are insignificant .
1980-86 EIA op. cit.

production: 1947-58: n.a., volumes are insignificant .
1959-76: API/AGA op. cit. Volume 32 Table XII-3.
1977-78: average of API/AGA and EIA figures.
1979-86 EIA op. cit.

Mcf converted to boe by ratio (1 boe / 6.0 mcf).

Note: Tables referenced are from sources given.

Columns 5,6 American Association of Petroleum Geologists, annual North American Drilling issues, later merged with World Energy Developments issues; and Oil & Gas Journal.

Column 7 (columns 2 + 5 from Table I) / (number of rig-years)
number of rig-years, from Hughes Tool Co., reported in e. g. Oil & Gas Journal, World Oil, etc.

TABLE IV
PRICES & RESERVE ADDITIONS PRE-1945

YEAR	Current Price	Price 1983 $	Reserve Additions (MM bbl)	Price / Reserve Additions (1983 $ / bil. bbl)
1918	1.98	20.02	656	30.52
1919	2.01	19.89	878	22.66
1920	3.07	26.79	943	28.41
1921	1.73	17.64	1072	16.45
1922	1.61	18.29	358	51.08
1923	1.34	14.14	732	19.32
1924	1.43	15.16	614	24.69
1925	1.68	17.99	1764	10.20
1926	1.88	20.21	1071	18.87
1927	1.30	14.05	2601	5.40
1928	1.17	12.62	1401	9.01
1929	1.27	13.28	3207	4.14
1930	1.19	12.92	1298	9.95
1931	0.65	7.62	251	30.36
1932	0.87	11.35	85	133.47
1933	0.67	9.00	606	14.86
1934	1.00	12.21	1085	11.25
1935	0.97	11.64	1220	9.54
1936	1.09	12.97	1763	7.36
1937	1.18	12.86	3722	3.45
1938	1.13	12.19	3054	3.99
1939	1.02	11.14	2399	4.64
1940	1.02	10.77	1893	5.69
1941	1.14	11.17	1969	5.67
1942	1.19	10.53	1879	5.60
1943	1.20	10.03	1484	6.76
1944	1.21	9.75	2068	4.71
1945	1.22	9.76	2100	4.65
1946	1.41	10.35	2658	3.89
1947	1.93	12.08	2465	4.90
1948	2.60	14.82	3795	3.91
1949	2.54	14.07	3188	4.41
1950	2.51	13.52	2563	5.28
1951	2.53	12.55	4414	2.84
1952	2.53	12.36	2749	4.50
1953	2.68	12.86	3296	3.90
1954	2.78	13.23	2873	4.60
1955	2.77	12.93	2871	4.50
1956	2.79	12.17	2974	4.09
1957	3.09	12.78	2425	5.27
1958	3.01	12.46	2608	4.78
1959	2.90	11.79	3667	3.22
1960	2.88	11.66	2365	4.93

TABLE IV (CONT.)

YEAR	Current Price	Price 1983 $	Reserve Additions (MM bbl)	Price / Reserve Additions (1983 $ / bil. bbl)
1961	2.89	11.78	2658	4.43
1962	2.90	11.74	2181	5.38
1963	2.89	11.62	2174	5.35
1964	2.88	11.41	2665	4.28
1965	2.86	10.87	3048	3.57
1966	2.88	10.68	2964	3.60
1967	2.92	10.42	2962	3.52
1968	2.94	9.98	2455	4.06
1969	3.09	10.00	2120	4.72
1970	3.18	9.69	2890	3.35
1971	3.39	9.47	2318	4.08
1972	3.39	8.92	1558	5.72
1973	3.89	9.34	2146	4.35
1974	6.87	13.48	1994	6.76
1975	7.67	12.76	1318	9.68
1976	8.19	12.44	1085	11.46
1977	8.57	11.61	1272	9.13
1978	9.00	10.88	1965	5.53
1979	12.64	13.17	1808	7.28
1980	21.59	19.47	2970	6.56
1981	31.77	24.30	2570	9.45
1982	28.52	20.59	1382	14.90
1983	26.19	26.18	2897	9.04
1984	25.88	27.00	3748	7.20
1985	24.09	25.85	3022	8.31
1986	12.66	13.95	1446	9.65

Sources:

Current price: 1918-1944 calculated from Crude Price Index, Twentieth Century Petroleum Statistics, 1986, Degolyer and MacNaughton, p. 98.
1945-1986, U.S. wellhead price from EIA Annual Energy Review.

Deflator: 1918-1945, Long Term Economic Growth 1860 - 1965, U.S. Department of Commerce, October 1966, p. 200.
1945 - 1986 see column 7 Table II.

Reserve additions: 1918 - 1944 see column 1.
1945 - 1986 see column 7 Table II.

TABLE V

REGRESSION RESULTS: DETERMINANTS OF RESERVES ADDED

Equation No.	CONSTANT	CUMULATIVE OUTPUT	(CUM OUTPUT)*(CUM OUTPUT)	DRILLING FACTOR PRICES	NOMINAL PRICE	adj. RSQ	F-stat	D-W
			LOGARITHMIC EQUATIONS					
1	3.69	--	--	-0.198	--	0.156	8.24	1.14
(t-stats)	34.04	--	--	2.87	--			
2	3.45	--	--	--	-0.092	0.042	2.7	1.04
(t-stats)	81.00	--	--	--	1.64			
3	5.05	-0.34	--	--	--	0.197	10.54	1.22
(t-stats)	9.87	3.25	--	--	--			
4	6.00	-0.54	4.590E-22	--	--	0.205	6.02	1.27
(t-stats)	6.32	2.71	1.18	--	--			
5	3.42	0.37	--	-1.58	0.928	0.481	13.02	1.62
(t-stats)	4.09	1.54	--	4.5	4.5			
6	3.52	0.04	1.540E-22	-1.57	0.9	0.466	9.52	1.62
(t-stats)	3.65	1.37	0.21	4.44	3.76			
7	4.67	--	--	-1.14	0.75	0.461	17.7	1.57
(t-stats)	21.08	--	--	5.53	4.47			
			ARITHMETIC EQUATIONS					
8	2860	--	--	-6.31		0.068	3.8	1.23
(t-stats)	15.8	--	--	1.96				
9	2621	--	--	--	-6.07	0	0.19	1.15
(t-stats)	15.8	--	--	--	0.45			
10	3377	-0.01	--	--	--	0.164	8.6	1.41
(t-stats)	11.6	2.94	--	--	--			
11	4734	-0.048	2.30E-07	--	--	2.12	6.24	1.54
(t-stats)	5.94	2.26	1.82	--	--			
12	3617	-0.0065	--	-34.3	141.8	0.459	12	1.98
(t-stats)	12.9	1.18	--	3.52	4.65			
13	3790	-0.015	3.60E-08	-34.7	139.1	0.445	8.81	1.98
(t-stats)	4.34	0.47	0.21	3.45	4.01			
14	3351	--	--	-42.1	153.3	0.453	17.2	1.88
(t-stats)	20.1	--	--	5.83	5.27			

TABLE VI
PRODUCTION EXPENSES, TAXES, & ROYALTIES,
OIL & GAS, USA, 1955-1986 ($ in millions)

YEAR	GROSS REVENUES	NET REVENUES	RATIO NET TO GROSS
1955	7848	4895	0.624
1956	8347	5153	0.617
1957	N. A.	N. A.	N. A.
1958	N. A.	N. A.	N. A.
1959	9031	5705	0.632
1960	9211	5964	0.648
1961	9562	6187	0.647
1962	9919	6401	0.645
1963	10295	6673	0.648
1964	10405	6731	0.647
1965	10653	6815	0.640
1966	11429	7152	0.626
1967	12274	7795	0.635
1968	12964	8136	0.628
1969	13882	8755	0.631
1970	14919	9353	0.627
1971	15789	9896	0.627
1972	15893	9918	0.624
1973	17952	11383	0.634
1974	28154	18724	0.665
1975	32061	21433	0.669
*1975	32798	21908	0.668
1976	36709	24418	0.665
1977	42445	28346	0.668
1978	47850	31718	0.663
1979	60538	40819	0.674
1980	93629	59048	0.631
1981	135615	74711	0.551
1982	128195	73220	0.571
*1982	135590	79896	0.589
1983	126620	72173	0.570
1984	132590	75576	0.570
1985	122050	69569	0.570
1986	75060	48414	0.645
Avg 1955-80			0.645
S. D.			0.016
Avg. 1981-82			0.570
S. D.			0.016

TABLE VI SOURCES:

Gross Revenues:
1955-1975: Joint Association Survey, Part II
1975*, 1976-1982: Bureau of the Census, Annual Survey of Oil & Gas.
1982*, 1983-1986: Department of Energy, Annual Energy Review.

Net Revenues:
1955-82: Gross Revenues minus royalties, production outlays, and taxes, from J.A.S., 1955-1975; from Census, 1975*-1982.
Net royalties assumed 15 percent of gross revenues, less royalties received by operators.
Net royalty averaged 12.7 percent 1955-1982, assumed so for 1982*.

1983-85: Ratio of Net to Gross for 1981-82 used, to account for Windfall Profits Tax in effect.

1986: Ratio for 1955-80 used, assuming that Windfall Profits Tax not in effect due to fall in prices.

TABLE VII
WELLHEAD PRICE, COST, AND RESERVE VALUES
USA 1946-1987
(CURRENT DOLLARS PER BARREL)

YEAR	WELLHEAD PRICE GROSS	WELLHEAD PRICE NET	AVERAGE RESERVE VALUE	DEVELOPMENT COST PRE-TAX	DEVELOPMENT COST POST-TAX	USER COST (VALUE LESS POST-TAX COST)
1946	1.41	0.91	0.30			
1947	1.93	1.24	0.43			
1948	2.60	1.67	0.75			
1949	2.54	1.64	0.73			
1950	2.51	1.62	0.70			
1951	2.53	1.63	0.73			
1952	2.53	1.63	0.68			
1953	2.68	1.73	0.75			
1954	2.78	1.79	0.69			
1955	2.77	1.78	0.89	0.87	0.78	0.11
1956	2.79	1.80	0.95	0.95	0.84	0.10
1957	3.09	1.99	0.94			
1958	3.01	1.94	0.91			
1959	2.90	1.87	0.88	0.72	0.64	0.24
1960	2.88	1.85	0.83	1.02	0.91	-0.08
1961	2.89	1.86	0.83	0.87	0.77	0.06
1962	2.90	1.87	0.87	1.15	1.03	-0.15
1963	2.89	1.86	0.83	1.04	0.93	-0.10
1964	2.88	1.85	0.87	0.64	0.57	0.30
1965	2.86	1.84	0.83	0.53	0.48	0.35
1966	2.88	1.85	0.84	0.54	0.48	0.36
1967	2.92	1.88	0.82	0.56	0.50	0.32
1968	2.94	1.89	0.83	0.71	0.63	0.20
1969	3.09	1.99	0.85	0.85	0.75	0.10
1970	3.18	2.05	0.81	0.63	0.56	0.25
1971	3.39	2.18	0.90	0.68	0.61	0.29
1972	3.39	2.18	0.99	1.10	0.98	0.01
1973	3.89	2.51	1.41	0.89	0.79	0.62
1974	6.74	4.34	2.28	1.46	1.30	0.98
1975	7.56	4.87	2.39	2.99	2.66	-0.28
1976	8.19	5.27	2.74	4.17	3.71	-0.97
1977	8.57	5.52	3.03	3.85	3.43	-0.40
1978	9.00	5.80	3.39	2.76	2.45	0.94
1979	12.64	8.14	4.62	3.35	2.98	1.64
1980	21.59	13.90	7.91	3.48	3.10	4.81
1981	31.77	17.51	9.72	6.42	5.71	4.01
1982	28.52	16.28	8.31	11.29	10.05	-1.74
1983	26.19	15.43	8.52	4.00	3.56	4.96
1984	25.88	16.67	8.80	3.60	3.20	5.60
1985	24.09	13.80	8.19	4.08	3.63	4.56
1986	12.66	8.15	5.88	4.96	4.42	1.46

TABLE VIII

REGRESSION RESULTS: SALES VALUE OF OIL/GAS PROPERTIES 1986-87

A. Beninger & Arndt

EQUATION	CONST ($ MILLIONS)	MONTHS	OIL ($/BRL.)	GAS ($/MCF)	ADJ RSQ	F-STAT
1	4.59	0.13	3.14	0.765	0.98	746
(t-stats)	(.33)	(.140)	(6.71	(34.1)		
2	--	0.42	3.19	0.766	0.98	1142
(t-stats)	--	(.340)	(7.26)	(35.1)		
3	--	--	3.24	0.768	0.98	2255
(t-stats)	--	--	(7.38)	(35.1)		

B. Salomon Brothers

EQUATION	CONST	OIL ($/BRL.)	GAS ($/MCF)	ADJ RSQ
1	-7.4	4.81	1.71	0.97
(t-stats)	(-3.6)	(12.7)	(17.3)	
2	--	4.44	1.55	0.94
(t-stats)	--	(9.4)	(13.6)	
3	--	4.34	0.74	0.44
(t-stats)	--	(9.9)	(7.4)	

Sources:
Beninger & Arndt: Oil & Gas Journal, October 12, 1987. Non-reserves assets excluded. Equation 4 formed by dividing all terms in Equation 3 by estimated value of property sold. See J. Kmenta, Elements of Econometrics (1984), p. 287, to which my attention was drawn by Harindar DeSilva.
Salomon Brothers: Salomon Brothers, Petroleum Exploration & Production, February 2, 1988.

SOURCES, TABLE VII:

Gross Price: Table IV.

Net Price: Ratio Net to Gross, Table VI.

Average Reserve Value: Adelman, DeSilva and Koehn, 1987.

Development Cost:
Pre-Tax: Table II.
Post-Tax: See Below.

User Cost: Reserve Value minus Post-Tax Development Cost.

POST TAX COSTS:

The reduction in cost aims to capture the net advantage of drilling for oil instead of buying. This is the result of the tax advantage of charging off intangible drilling expenses. The percentage depletion allowance, repealed for nearly all properties in 1975, affected the value of a property, whether obtained by buying or by drilling.

Intangible drilling costs are "between 60 and 70 percent of the entire well cost". (Petroleum Production Handbook 1962, page 38-22, repeated at page 44-11 of Petroleum Engineering Handbook, 1987). however a special API tabulation released in 1985 showed intangibles as 34 percent in 1984. this discrepancy is due to the fact that drilling and completion account for only about 60 percent of total development cost including lease equipment, pressure maintenance programs, etc. For the whole period, therefore, development outlay post tax is reckoned at 83 percent of pre-tax, by the formula: $X=1-(.34)(1-.5)=.83$. The net present value is 63 percent of the gross saving. This is calculated by assuming that cost would otherwise be uniformly charged off over 25 years, and discounting at 10 percent this would be worth 0.367 of an immediate payment, i.e. $1-.367=.633$. Then $0.17(.63)=0.11$, and development cost is reduced by 11 percent.