THE COMPETITIVE FLOOR TO WORLD OIL PRICES

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Abstract

In this OPEC crisis or the next, oil prices may fall to the competitive floor. At the high-cost end of the spectrum, it would take a price as low as $4 to produce an immediate shutdown of nearly half of capacity in the United States, and as low as $2 to do the same in the North Sea. A price of $10 would stop development investment for the bulk of U.S. oil and over a third of North Sea oil. Capacity would therefore decline by roughly 6 percent per year. At the low-cost end, assuming continued competition and completely independent decision-making, a price of $5 would make it profitable for the OPEC nations to expand output to about 60 million barrels daily. This price would be sustainable past 1995. This projection is not a forecast, however.

Years ago, the author suggested that there was no oil shortage current or impending. Growing consumption, static U. S. U. S. production, and other reasons offered then and now, did not imply rising prices. There was (and is) a hidden major premise, failing which the conclusion makes no sense. One must assume rising pressure on reserves, signaled by rising costs of maintaining and expanding output. There was no sign of this.

But the oil-exporting nations had in 1970-71 tasted the fruits of collusion on a modest scale. "The genie is out of the bottle." They would try harder to get more. [Adelman 1972]

The cartel was a great success, but overreached. Lower consumer demand and rising non-cartel output cut their exports drastically. In theory, the members could have agreed--can still agree--on sharing the smaller pie, to leave them all better off. In practice, they have not been able to agree.

The burden of output cutbacks was shoved on to the biggest member, as is usual in coalitions. (The United States in NATO and Asian defense is another example.) When Saudi exports fell to near zero last summer, they had to make good on their repeated threats. They began to sell under netback contracts, which set no bottom at all to prices.

The Saudis may be able, by judicious infliction of pain[1], to rally the troops to get the price back to the neighborhood of $20. If so, then barring military action by producing nations, to remove productive capacity by force, the underlying surplus will remain indefinitely as consumption stagnates and non-cartel output creeps up. The cartel will bump from crisis to crisis.

At some point, conceivably, the price may fall to the competitive floor. It is worth trying to locate, however approximately, the short- and long-term competitive price level.

We look at the two ends of the spectrum of producing areas. Our results in brief: at the high-cost end, it would take a price as low as $4 to produce an immediate shutdown of nearly half of capacity in the United States, and as low as $2 to do the same in the North Sea. A price of $10 would stop development investment for the bulk of U. S. oil and over a third of North Sea oil. Capacity would therefore decline.

At the low-cost end, assuming competition and completely independent decision-making, a price of $5 would make it profitable for the OPEC nations to expand output to over 60 million barrels daily. The price would be sustainable past 1995 at the

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[1] It is hard to imagine any greater encouragement than to hear from the Vice President of the United States how much pain they are inflicting. One is reminded of how an Undersecretary of State was despatched to the Persian Gulf in January 1971 to inform the producers there of how much damage they would inflict by an embargo. These lessons are learned.

least.

Shutdown Costs for North Sea and USA

We take account only of strictly economic costs, disregarding taxes, royalties, and other charges, which vary from country to country. They can and will be changed by governments, in response to the bad news. Those quicker to adapt will be penalized less than the more stubborn.

[TABLE I HERE]

Operating costs As Table I shows, during 1983-84, operating costs in the British North Sea averaged a little over $2 per barrel. From what is known about the distribution of those costs [OGJ, 1986a], approximately 60 percent of North Sea oil is produced at or below average cost, and 80 percent is produced at or below twice the average. Hence it would take a price as low as $4 to reduce North Sea output by 20 percent.

[TABLE II HERE]

In the United States, as Table II shows, 1982 average operating costs were $4.84, which we have reduced to just under $4 to take account of a decline since then.[DOE/EIA 1986, table E1] Since they include some allocation of overhead, they overstate true variable costs. In the 1960s, the distribution of well costs seemed to have a longer thinner "tail" than in the North Sea. About 65 percent of production was at or below average cost, and another 30 percent at or below twice the average. [Adelman, 1972]. This may still be true.[2] If so, a price of $8 would have little effect, but a price of $4 would suppress more than one third of U. S. production, practically overnight.

Thus even a very low price would not quickly shut down oil production, even in the highest-cost areas. But to the extent that it was no longer profitable to invest in additional capacity, there would no longer be any offset to the natural decline rate in all reservoirs, which would reduce production. In general, the fraction of known reservoirs that would continue to be developed would vary with the price. We would like to know the price which would at least maintain development.

There is, however, a qualification. Suppose the price falls to $8, and an operator expects that it will revive to $29 by 1995 [API 1986]. For an average developed barrel, costing $4 to produce, and perhaps 20 percent of the price in roylaties and state and local taxes, the gross return would then be as follows:

Year	Price	Cost	Taxes, Royalties	Net
1986	$8	$4	$1.60	$2.40
1995	$29	$4	$5.80	$19.20

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[2] For example, the Kern River field in 1985 had 6254 wells producing 139 thousand barrels daily. [Oil & Gas Journal, January 27, 1986, p. 104] Average output was thus 22 bd per well. In early 1986, 1500 wells were closed, which had produced 17 tbd, an average of 11 bd per well. [Wall Street Journal, March 12, 1986, p. 5] Thus the highest-cost 12 percent of output was produced at a cost about twice the average for the field.

Whether the eight-fold return in nine years (26 percent per year) is "*good enough*" depends of course on the risk attached to it. Or to state the problem a little differently: considering production in 1995 as an option, how much would it be worth in the market?

The need to ask these questions is more important than any answer. Discussion of the oil market has long been plagued with such confusions as the alleged "wide gap between full and marginal costs"; if "full cost" means average cost, then marginal cost may be much more or much less. A false assumption which cripples thought is that the price floor is "the out-of-pocket cost of the last barrels", because investment is a "sunken cost". If this were true, nearly every single industry would show wild price gyrations at all times, because investment would have no effect on price. But in oil as elsewhere, the statement is untrue under any conditions.

Oil development consists in spending large sums of money to build a shelf inventory, "proved reserves". No manufacturer or shopkeeper will give away his wares because his stock-in-trade is a "sunk cost". What he sells he must replace. Even if he is going out of business, others are staying, and will pay their replacement cost for his inventory.

In oil too, the true price floor includes replacement cost. The problem in world oil is the excess of price over operating-plus-replacement cost for the great bulk of the world's reserves.

<u>**Development cost**</u> Table I shows that oil development investment in the U.K. North Sea was about \$5.5 billion in 1983-84 (converting the pound sterling at \$1.50). Since output was equal to capacity, the increase from 2.029 to 2.449 million barrels daily represented a net capacity gain of 420,000 b/d over two years. But since there was a continuing decline in old reservoirs, the capacity lost and replaced during those two years must be added back. This can be approximated by assuming that the ratio of production to reserves is about equal to the decline rate, as would be true under conditions of constant exponential decline for an unlimited period.[3] There is reason to think this exaggerates the decline rate for 1984, but the error is offset by an error in the opposite direction. (See next paragraph.)

The North Sea development outlay of about \$5600 per initial daily barrel is for a diminishing flow. The amount per barrel which would make production just barely worthwhile is found by multiplying the investment by the sum of the depletion/decline

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[3] Thus if initial output = Q, and the annual decline rate = $\underline{a}$, output in any year $\underline{t}$ = $Q_t = Q\,e^{-at}$, and proved reserves $R = \int Q\,e^{-at}\,dt = Q/a$ or $a = Q/R$.

rate and the minimum acceptable rate of return.[4] In the U. S. capital market in early 1986, the riskless rate of return, on U. S. Treasury bonds, was about 8 percent. It has declined because of lower inflation, and may decline further. Adding the risk premium on oil operations, which according to various researchers seems historically to be about 8 percent, yields a total 16 percent. Added to the apparent 13.5 percent decline rate (which constitutes the offset), a total return of 29.5 percent is necessary: initial year cash flow as percent of up-front investment.[5]

In the United States, development expenditures were calculated by using the 1984 <u>Joint Association Survey</u> to update what is unfortunately the last (1982) issue of the Census <u>Annual Survey of Oil & Gas</u>. Division of total development expenditures

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[4] That is, $NPV = PQ \int_0^\infty e^{-(a+i)t}\,dt - K = 0$
Then $PQ/(a+i) = K$
and $P = (K/Q)(a+i)$ = supply price

[5] The risk premium on oil operations is a thorny question, of course. Recent price declines might be a reason for increasing it. Yet since 1973, oil price changes have been if anything negatively correlated with changes in incomes and asset values generally. Hence the covariance with the general asset market may not be much more than that of other kinds of company share ownership.

If we could assume that oil prices will henceforth move approximately with the general price level, we would use the real not the nominal cost of capital, not 16 percent but 10 percent. Then the total required return would be 23.5 percent. The same is true for the United States and other areas, as set forth below.

between oil and gas was made in proportion to the respective drilling development expenditures. An estimate of the increment to capacity would be a much less reliable number than the gross addition to reserves, which in 1984 was 3748 million barrels, or \$3.78 per barrel in the ground.[6] We are forced to exclude natural gas liquids (from associated-dissolved gas production), since this number is no longer compiled by DOE/EIA. [DOE/EIA 1984] This results in a small cost overstatement.

The in-ground cost per barrel is converted into a wellhead cost per barrel by a method which is mathematically equivalent to the one used for the North Sea. [Adelman 1986, Appendix A] The cost of holding the reserve barrel until produced and sold off varies directly with the cost of capital, and inversely with the depletion/decline rate; the quicker it is produced, the cheaper to hold. In the United States, where $\underline{i}$=the discount rate and $\underline{a}$=the depletion/decline rate, the multiplier $(1+(i/a)) = (1+(.16/.115)) = 2.39$. Hence the average development cost at the wellhead is reckoned at \$9.04.

If the real not the nominal discount rate is used, the multiplier is $(1+(.10/.115))=1.87$, and wellhead cost = \$7.07. This would be relevant if and when one thought the price of oil had really gone to competitive equilibrium levels, and would

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6 Another fortuitous resemblance: 3.78 is not 3748 scaled down.

henceforth fluctuate with the general price level, modified by its own supply and demand.

Summary: UK & USA In the North Sea, the sum of average operating plus development costs is a bit less than $7 per barrel. Therefore a $7 price, net of all taxes, would support continued development of about half the U.K. fields. At $14, or twice the average, nearly all fields would still be worth further development. In the United States, average development-plus-operating cost is about $13, so a $14 price would stop development in fields accounting for nearly half the total. A price of $10 per barrel would stop development investment for the bulk of U. S. oil and over a third of North Sea oil.[7] (For effects on exploration, see below, p. 11.)

At this point, we must digress to deal with a widely-cited estimate which cannot be reconciled with the real world.

The myth of "$70,000 per daily barrel in non-OPEC"

A little mental arithmetic shows this is impossible. It is twelve times the 1983-84 average for the British North Sea, and would therefore require a price of over $85, after taxes, to break even. (That is, ($70,000/$5300)*($4.43+$2.12)=$86.51.) In

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7 The distribution of development costs probably has not as long a tail as operating costs, because development costs are a larger portion of the total. Hence a price double the average of development cost would preclude a somewhat higher portion of the total than a price double the average of operating cost.

the United States, the breakeven price would be even higher.

Not long ago, most oilmen doubtless believed such a price was coming--some day. But to suppose they spent billions up front at this rate, for years on end, without losing their shirts, their jobs, or their companies to takeovers or stockholders' suits, is not credible. Even in 1982, when reputable consulting firms were predicting $200 per barrel, a North Sea development was cancelled because it would have cost $4 billion to develop about 300 million barrels [NYT 1982], very roughly $44,000 per daily barrel.[8] Thus even around the height of the delusion, an investment only 63 percent of the supposed <u>average</u> cost was ruled out.

<u>Finding cost (resource value)</u> We have assumed up to now that the decline rate would stay constant. That is not true. Without newly found reservoirs to "freshen up the mix", increasingly intensive development is bound to increase the percent of reserves depleted every year, and the rate of production decline. That is what happened in the United States after about 1965.

A price double the average development cost supplies an incentive for exploration to find low-cost fields. There is some

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[8] Let K=investment, Q= initial daily output, R= reserves, and a=the decline rate. Then as shown earlier, Q=Ra/365. Then K/Q is equal to (365/a)*(K/R). If a is taken as approximately 11 percent, then $K/Q=(365/.11)(\$4*10^9/300*10^6)=\$44,231$.

indirect evidence bearing on this question: the per-barrel value of a reserve sold in the ground.

In late 1985, the price of a barrel of oil in a developed reserve was $6, give or take $1. [OGJ 1985] However, an allowance for the tax benefits of drilling would raise the pre-tax cost to about $7. If our estimate in Table 2 is correct, this divides neatly in half, and the value of undeveloped oil in the ground was $3.50 per barrel. With the collapse of oil prices since late 1985, this value must today be much lower. Except where expected finding cost (excluding development) can be brought this low, or lower, it does not pay to explore.

Unfortunately, we cannot compare the value of an undeveloped barrel in the ground with the cost of finding it. There are no data from which to estimate finding costs per unit. There are data on exploration **expenditures**, the most recent from 1982. But there are no data on the amount of newly found oil, aside from the usual meaningless "finding" which lumps together development and discovery.

The published EIA statistics on "discoveries" are fragments masquerading as data. This is because the initial-year estimates are only a minor fraction of what will ultimately be credited to a new field or pool. Through 1979, the American Petroleum Institute and American Gas Association published a valuable series of backdated oil and gas discovery estimates, but this (and much else) was lost when their series ceased to be published, a casualty of mindless hostility to the oil and gas industry. [Cf. National Academy of Sciences 1985]

Hence we have no information on finding costs per unit. Estimates published under that heading are meaningless. However, it seems plausible that not enough can be found even at $3.50 to maintain the reservoirs. In fact, for many years, most of the additions to reserves have come from the old fields, both by improved recovery and by adding to the known oil in place.

To sum up: in the USA and the North Sea, a $20 price (at which price the Windfall Profits Tax becomes irrelevant) would make the continued development of known prospects profitable, except for extremely high cost wells. It would also supply an incentive for exploration of good prospects, i. e., those whose combined cost would not exceed $20. But many leases would not be worth further investment, and production would decline slowly, unless costs were sharply reduced.

Costs have of course come far down, and reductions in deepwater offshore have been dramatic. Hence the currently (June 1986) reported cutbacks in oil production capital spending do not mean an equally great a cutback in real effort and investment. Morever, efficiency is rising steeply, both because of better use of equipment, and because the poorer prospects are cut first. The collapse in drilling has not been matched by the number of wells drilled and feet drilled. Rigs operating during January-February 1986 were a third less than the same months of 1985 [MER 1986], but well completions and footage were actually a little higher. [OGJ 1986d] Moreover, much of the spending and drilling cutbacks have been precautionary, a waiting until the dust settles. In the North Sea and elsewhere, lower taxes will restore profitability to some projects currently uneconomic.

Other non-cartel areas areas Some resemble the U. S. and U. K. because they are competitive, and production is carried to where incremental cost equals price. Here lower prices would force cutbacks.

But many and probably most non-cartel countries have been explored and developed below their potential. In such countries, reserves and production will increase because government and public opinion are, with agonizing slowness, shedding the illusion of oil and gas as appreciating assets, worth keeping in the ground. This illusion is powerfully reinforced by the notions, so vague as to defy analysis and common sense, that oil is "strategic", whatever that means; that oil deposits are family heirlooms not vulgar commodities to be managed for maximum return. They will begin to negotiate and to tax on the basis of prices as they really are.

For example, the world price decline after 1981 caused the abandonment of the National Energy Program in Canada, other reforms, and an investment surge. The Dutch turned from cutting back exports to actively seeking customers. The price collapse of early 1986 led Norway to accept a price for the Troll and Sleipner gas fields [OGJ 1986c] which was half (or less) of what they had previously been demanding. The development is the direct result of lower prices. The probability of revising government policy, in order to minimize the loss of revenue, is what makes pre-tax calculations relevant.

Taking the non-cartel areas as a group, if the price is raised back to $20, there is no basis for supposing that they will have lower reserves and production in 1995 than they do today. But a price in the $4--$8 range would indeed shrink the oil industry there. An intermediate price is much harder to read.

We turn therefore to the low-cost areas, to see what, under competitive conditions, would be available at such a range of prices.

The Supply Function in the OPEC Areas

The competitive floor price In 1970, the Persian Gulf price was $1.20, which at present-day drilling cost levels would be about $3. Supply was ample, and the price was stable, tending to decline very slowly. How different would things be in the 1980s and 1990s?

With no cartel, each producing nation would become a price-taker. To maximize returns, they would increase output to where the incremental cost of more production approached the market price. They might yearn for the good old days of the cartel, but that would not matter so long as they could do no more than yearn.

As with the North Sea and USA, we need to know how much money must be spent to obtain a barrel of daily capacity, to be translated into a cost per barrel.

[TABLE III HERE] [FIGURE 1 HERE]

Table III shows the calculations underlying Figure 1. We have the estimated curve for the year 1995, allowing ten years for some of the OPEC nations to build capacity up to 5 percent of their proved reserves. The industry rule of thumb is 1/15th annual depletion, or 6.7 percent. In the U. S. A. and the U. K., depletion rates are above 10 percent. (Cf. Tables I and II.)

Our reference year is 1978, the last year before data were radically distorted by the second price explosion and the output cutbacks. Line 1 shows the number of wells of all types completed that year, line 2 the average depth of well. Line 3a shows the average cost of an onshore well in the USA at that depth. For Iran and Nigeria, however, we choose not the average value but the maximum, to allow for exceptionally difficult drilling conditions. For countries which produce both onshore and offshore, we multiply by the ratio, calculated from the Joint Association Survey, of well costs for all wells to well costs of onshore alone, yielding the adjusted average well cost in line 3b.

In addition to drilling and equipping wells, there are also the outlays on lease equipment, improved recovery systems, overhead, and other portions of total development cost. These have historically averaged 66 percent of drilling costs, with little variation. Well cost must be scaled up by that percentage.

Multiplying (a) the number of wells drilled by (b) the drilling plus non-drilling cost for each well, yields total drilling- related expenditures, in line 4. This includes gas wells and equipment, and exploratory drilling (but not geo-logical- geophysical work), which ought to be excluded; but the total is considered oil development expenditure.

Operations outside the United States tend to be more expensive where there is no infrastructure in place, of people and service industries, and supplies. But these are all mature producers. Furthermore, we take no account of local peculiarities, public or private, which increase the expense, but are not necessary.

New capacity is calculated by taking the adjusted average production per well per day (line 7b), and assuming that the average new well produces as much as the average old well.

This average is multiplied not by total wells drilled, but only by new successful oil wells, to yield gross new capacity added, country by country (line 9b). There is a factor of overstatement here, because some successful oil wells are exploratory holes, which in themselves do not add to capacity. However, exploration was at a low level in these countries, a fact to be discussed more fully below.

Dividing total investment (line 4) by new capacity added by drilling (line 9b) yields investment per additional daily barrel (line 10b). We must now translate this into cost per barrel by the same method as was applied to the North Sea.

We assume the production decline to be equal to the 1995 production/reserve percent, in this case 5 percent, as would be true of exponential decline over an infinite period. Operating expenses are assumed to be 7 percent of investment. The total gross rate of return is 36.5 percent, which makes mental arithmetic easy. (For example, if the investment per daily barrel is one thousand dollars, then unit cost=$1000*(.05+.07+.245)/365 =$1.) However, this is fortuitous. We assume a cost of capital, in nominal terms, 24.5 percent. This is half again as high as what it would be for a private oil and gas operator in the United States or similar developed countries.[9]

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[9] In a forthcoming paper, it will be explained why the discount rate for an oil-producing country, whose oil income is a large part of its revenues, must be considerably higher than for

The limitations on these estimates are several. First, like the U. S. but unlike the North Sea, they are strictly wellhead costs, with no allowance for transport. Second, they are costs per average well. This involves some opposing biases.

On the one side, the cost per barrel from the average well may and usually does overstate the cost per barrel from all wells. This happens when (as in the United States) there is a long thin tail of small wells. This can be adjusted for by calculating a weighted average flow rate, weighting the average flow rate for each field by the production of the field. [Adelman & Paddock, 1980] A weighted average of all wells would be preferable but is impossible. The weighted average flow rate is shown in line 7b. It is usually higher, but sometimes lower, than the unweighted average in line 7a.

But even an adjusted average cost curve is not a supply curve. As we pointed out earlier in discussing the USA and the UK, a substantial fraction, less than half, of the oil is produced at costs above average. Hence for each country one must make an allowance for the more expensive output. Our procedure is to multiply the average cost, line 10b, by 2.5, yielding the supply curve segment of line 11. This adjustment in effect yields a 50 percent or greater rate of return for more than half the existing capacity, which serves as an incentive to discovery of

a private operator.

new fields. Hence we have a substantial implicit allowance for exploration costs.

It need not be said that every item has a wide margin for error. Indeed, among the lowest-cost suppliers, the order tells more about our adjustment rules than about true relative costs. For example, Saudi expenditures were unusually high in 1978 because of a great water-injection project, and oil wells relatively low, while Libya was completing an unusually large number of oil wells that year.

For some of these countries, going to 5 percent depletion involves a very large buildup. For example, in 1978, Saudi Arabia produced only 2.6 percent of its proved reserves. We assume that investment per unit is proportional to the depletion rate. Hence the Saudi investment is increased in the proportion 5.0/2.6, or by 92 percent. This represents a considerable overstatement, because reserves would be increasing along with capacity. We keep the assumption, however, in order to be consistent with a later treatment. (See below, the "zero reserves-added model".)

The supply cost for the group as a whole is that for the highest-cost members, Venezuela and Nigeria. The 1978 cost (at 1985 factor prices) in Nigeria was $2.00. With much of its output known to be at higher costs, we multiply the average by 2.5, reaching $5.00. Producing at 5 percent of 1985 proved reserves would be a slightly higher percent of reserves than in 1978, although the absolute amount would be lower, hence the supply price increases only slightly.

Venezuela and Nigeria are the only countries where estimating errors make any difference. For the others, even large relative errors would be negligible in absolute terms. That is, if the true cost is twice our calculated cost, and the latter is 50 cents, the error is only 50 cents. There is no way of changing the conclusion: in these countries, oil ranges from cheap to dirt cheap.

Declining oil prices have lowered costs greatly, both by lower factor prices and by greater efficiency. Costs will undoubtedly decline from 1985 levels, but we cannot tell by how much.

How Long Can a Competitive Price be Sustained?

We have assumed that it takes a decade to reach equilibrium. We need to estimate rates of reserve buildup and drawdown before we can start to answer the ultimate question: still assuming competition, how long can this price level be sustained?

World non-Communist consumption in 1985 was 45.5 million barrels daily [DOE/EIA/ICID, March 1986, p. 10], of which 39 mbd was supplied by crude oil [OGJ March 10, 1986, p. 80], and the rest by natural gas liquids, Communist block exports, and inventory drawdown. We focus on crude oil supply and demand.

At much lower prices, consumption would increase. We assume average annual economic growth at 3 percent, and an oil:GNP ratio annual growth of 2 percent, for an oil consumption growth rate of 5 percent.[10]

Table IV shows that this consumption turnaround could be supplied entirely from the stock of proved reserves at end-1985. Non-cartel oil production is assumed to decline steadily at about 8 percent per year, which is almost surely excessive, while output of cartel oil (OPEC plus Mexico) would increase by a factor of three. Most of the growth in cartel output would merely reactivate capacity already in existence in 1985.

Table IV is a model not merely of zero discoveries but of zero reserve additions from known fields. In any given time period these are always the great bulk of all reserve additions. Nevertheless, there is no problem of supply at the competitive floor price for a decade. It is during this time that reserves

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[10] I think the reaction would be slow, because of (1) improved technology in combustion and building; (2) the developed countries have been approaching the North American level of automobile saturation; (3) excise taxation of oil products by consuming-country governments; (4) the retrofitting asymmetry. Part of the reaction to higher prices was the alteration of existing structures; but the alteration will not be undone because of lower prices. Insulation will not be ripped out of buildings.

would in fact be added, at the cost per barrel shown in Table III, to support consumption after 1995.

Sustainability after 1995 It is conservative to assume that enough additional reserves will be created during ten years, at the costs shown in Table III, to supply the world for a few years, at least, past 1995. But we consider it a mistake to estimate the rate of reserve additions as if they were some kind of exogenous fact. Reserves are ready shelf inventory. The rate of reserve-building results from profit-maximizing investment decisions, which are radically different under competition and monopoly.

Any monopoly must restrict output in order to maintain price. Hence there is under-investment. With a reversion to competition, the rules governing investment would again be turned upside down to be right side up.

In a competitive market, low-cost sources of supply grow faster than high-cost. This was true before the 1973 price explosion. It was evident in the bitter 20-year fight in the United States over restricting imports. Since 1973, water has been running uphill. Drilling in the USA increased by a factor of four through 1985. In Saudi Arabia, drilling dropped by two thirds, because only sharply lower production would maintain the price.

If the monopoly disappeared, and every producer acted independently, competition would first induce full use of their existing capacity, and then set them off on an investment boom. They would hate it, of course, and some of them would have real financial problems in raising the relatively small amounts needed. But the only way to save something from the wreck of the cartel would be to explore, develop, and produce to the maximum.

The difference between oil and uranium is instructive. After 1974, the price of uranium soared almost as spectacularly as oil. But there was no cartel to restrict investment. Accordingly, there was a massive increase in supply. Less than five years after the first surge, uranium prices began to drop, and went to the lowest level since they were first recorded. [Neff 1984] The "Neff paradigm" will hold also in oil if the monopoly disappears; the question is how far down the price will go.

We look first at development of known fields, which provide the great bulk of new reserves added in any time period.

In 1944, a team of distinguished geologists calculated Persian Gulf oil reserves at 16 billion proved, 5 probable. Excluding later discoveries, this has already been surpassed by a factor of roughly 30. These geologists were neither foolish nor conservative; as good scientists, they interpreted from the data known then. As more is known, reserve estimates grow.

For Saudi Arabia to produce 20 million barrels daily requires them only to dust off the 1973 plans for 1980. Of the 50 commercial oil fields discovered in that country, only 15 have been developed. If the price collapses, we will find out how much is in the other 35.

No OPEC country is as intensively drilled today as was the USA in 1945. Excluding Alaska, practically all the big fields had been found before that year. Proved reserves in 1945 were 20 billion barrels. But in the next 40 years the "lower 48" produced not 20 but 100 billion barrels, and they still have nearly 20 on the shelf.

Those additional 100-billion barrels plus were no gift of nature. Through heavy investment, many small fields were found, and the old fields were greatly expanded. Yet from 1945, at least through 1972, there was no increase in finding-developing cost. (Great turbulence, and disappearance of some statistics, make it difficult to say just what happened afterward, but there is reason to think the cost may have doubled in 1972-84.)

In Venezuela, another old province, reserves stagnated until costs began to creep up. They amounted to 18 billion barrels at end-1978. In the next seven years, another 13 billion were added, without major discoveries. A nationalized industry does not have the difficult problem of skimming the operator's rents without taking so high a percentage as to reduce the total take. In Nigeria, Indonesia, Malaysia, Egypt, and other places, better terms will be granted to local operating companies because it will minimize the revenue losses.

Turning now to exploration: it is prudent to assume that the oil industry will find smaller oil and gas fields than in the past.[11] It does not follow that newly-discovered oil will be less. It depends on the slope of the size-decline curve [Smith & Paddock 1984], and on the amount of investment in exploration.

The most promising areas of the world are the least explored. In Kuwait, the inadvertent result of drilling for gas for local power generation was the 1983 discovery of an oil field of about 30 billion barrels, so cheap to produce that it will replace part of current production. Kuwait is a tiny country. Saudi Arabia is as large as Texas and Louisiana combined. In 1985, those States operated an average of 963 rigs. Saudi Arabia averaged ten (10). Yet Saudi Arabia is a far better hunting ground. We will find out how much better when and if the cartel disappears--not before.

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[11] Prudence is not necessarily truth. It involves extrapolating the model of diminishing returns (see next page) from a given field or "play" to a whole country or continent or world. The extrapolation, as Kaufman has put it, "breaks the model's legs in several ways".

In a kind of twilight between exploration and development are large resources of heavy oils, especially in Canada and Venezuela. Much is profitable at a price below $10. Indeed, just as high prices and low demand put the Orinoco "belt" on hold, low prices and high demand would make it a major producer.

In short, the evidence points to a replacement of 1985-95 consumption at the cost levels of Table III, which is ample to accommodate consumption through 2000 A. D. There is too little basis for going farther, nor is there any need to. The change in marginal cost is an unknown with which buyers and sellers must somehow cope. The only meaningful question is: what would be the effect upon the supply price of oil in 1986-1990 of the unknown chance of sharply rising marginal cost after 2000 A. D.?

Long run cost and price changes

The belief that oil prices **must** somehow rise in the long term is grounded in the fact of diminishing returns. We need assume nothing about "exhaustible resources". The amount of a mineral in the Earth is unknown, and irrelevant. The "limit to growth" is cost at the margin.

In any mineral industry, *ceteris paribus* the biggest deposits are more likely to be found first, even by chance, because they are biggest. The best ones are exploited first. (Failure to do so, as we saw earlier, implies monopoly control.) Life is one long slide from good to bad and bad to worse. Hence marginal cost must keep rising over time, and the price with it. As the cost and price rise, consumption and production dwindles.

Yet for nearly 30 years it has been clear that there is no persistent widespread upward price drift; most minerals prices actually decline in the long run. Diminishing returns are opposed by increasing knowledge, both of the earth's crust and of methods of extraction and use. The price of oil, like that of any mineral, is the uncertain fluctuating result of the conflict.

Thus the value of a mineral body is subject to the kind of uncertainty found in every industry. Every mineral or non-mineral firm must reckon as a current cost the using-up of assets. That cost is the lesser of (a) the present value of the asset's future revenues or (b) the present value of reproduction cost. Either of these values is very uncertain, but there is no escape from the pain of choice for an investment decision. In fact, (a)/(b) is familiar to economists as "Tobin's Q". Mineral economics is merely an important special case.

In long run equilibrium, the fraction (a)/(b) approaches unity. We have an interesting example of a firm working out the problem at its leisure. In 1976, when Aramco was expropriated, the operating companies were allowed 6 cents (about 10 cents in 1985 prices) for every barrel discovered.

This gives us a fix on Saudi marginal finding costs (equal to user cost) and marginal revenues. The low value should not be surprising. Given proved reserves of 166 billion barrels (and probable reserves perhaps half again as great), and current annual output of 3 billion, the present discounted value of an incremental Aramco barrel was tiny almost without regard to the future price. Were Aramco producing at the levels hypothesized in Table III, development cost and also resource value ("user cost") would be much higher.

In 1976, in the United States, an undeveloped barrel in the ground would sell for several dollars. The future net revenue, i. e. the difference between price and operating-development cost, was only a small fraction of the margin in Saudi Arabia. But the present value of the smaller margin was many times as great because it would be realized within a few years not decades or centuries, if at all.

If current information indicates higher prices in the future, then it pays to refrain from investing in reserves which would be profitably depleted today, in order to save them for even more profitable future use. The higher the cost, the lower the current profit, and the greater the gain from postponement.[12] Or, what comes to the same thing: the lower the cost of

[12] Suppose this year's price for some product is $1, the relevant discount rate is 10 percent, and the best estimate of next year's price is $1.05. If the marginal cost (bare operating

creating the reserves (development cost), the lower the opportunity cost (user cost) of producing now rather than deferring production.

Thus the notion that the cartel nations were reserving their oil in the ground for later more profitable use is proved false by the fact that owners of higher-cost oil were striving to get it out more quickly, while the owners of lower-cost oil lagged far behind. This upside-down behavior is characteristic of a non-competitive industry with a competitive fringe.

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cost for facilities in place, development-plus-operating cost for facilities proposed) is 50 cents, production should be postponed to next year. That is, the net return would be 55 cents next year, which is 10 percent above this year. Or, what comes to the same thing, user cost is 5 cents, which added to marginal cost makes production this year unprofitable. But lower cost operations should not be postponed. In general, marginal cost is correlated with user cost; the higher the marginal cost the greater the gain to postponement.

Option theory adds another dimension. Suppose we have no estimate of next year's price, but we do have some estimate of the future variability of price. The greater its variability, the better the chance that some time in the future, the price will be sufficiently higher than now to make production so much more profitable as to be worth waiting for. Thus an operation with zero or negative current profits may have a positive present value. If there is a market in values, the individual needs no discount rate to make a decision. (But waiting may have costs over and above mere postponement. At the limit, it may be impossible to resume operation once it is halted.)

The important point for us is: The lower the current earnings, the greater the value of variable expectations. An operation "out of the money" is the best candidate for waiting; one "deep in the money" is the poorest. This is perfectly consistent with the maxim that we use the lowest-cost mineral resources first, and also with our thesis that user cost is positively correlated with development-operating cost.

Moreover, the increased cost of developing known reserves more intensively puts a limit on what is worth finding; some years ago, the writer called it Maximum Economic Finding Cost. [Adelman 1972; and see Devarajan and Fisher 1982] Hence an estimated increase in development cost is an implicit allowance for exploration cost.

Our only sensing device for future shortages is a competitive market price. Estimates and models of resources and reserves are inputs into price formation. Assumptions about conditions past 2000 A. D. will be discounted so heavily by rational actors that their influence is minor or imperceptible. The price reflects all the information, models, guesses, hypotheses, hunches, and mistakes. The fog surrounding any future price is like Napoleon's "fog of war". But the estimate of that future price is subject to constant correction.

The probability of marginal costs rising strongly after 2000 A. D., whatever it may be, will have little near-term effect, but a substantial effect ten years hence.

It is not unreasonable (even if unproved) to expect the competitive price of oil to increase over the long run from the current competitive "shadow price". What must forever amaze the historian is that when the price of oil was raised far above that competitive level, and was therefore subject to an additional <u>downward</u> risk, it was confidently expected to keep <u>increasing</u>.

[IIASA 1985] is about the most moderate and cautious (as it is one of the most recent) of innumerable analyses and forecasts of prices higher than 1981 or 1985.

Price forecasts But even if the price reaches, as in 1970 it approached, a level which expresses long-run supply and demand, it will probably not stay there. The cartel members need not wait for 2000 A. D. or even 1987. Lower sales have not directly forced down cartel prices. It is rather than lower revenues have made them resist the need to share burdens. But if they can make, and, more important, keep an agreement to cut production, they can quickly raise prices again.

The cartel's basic instability is that a movement in either direction becomes self-reinforcing and cumulative.

> "The better the financial condition of the sellers,... the less pressure on them to cheat and undersell each other in order to pay their bills...Once the price begins to slip, the OPEC nations will be under great pressure to produce more in order to acquire more revenue, and the more they produce, the further the price falls. [Adelman 1982]

Most likely, the price will fluctuate between the monopoly ceiling and the competitive floor. The ceiling seems first to have been envisaged around $28, but more recently OPEC spokesmen have spoken of $20. The floor as we perceive it here is about $8 in the short run, below which there will be large cutbacks in U. S. production, and $5 in the longer run, which would suffice to maintain a flow of investment in new reserves and capacity in the ex-cartel area, and elsewhere.

Concerted output cuts by the revived cartel would as in the past be a clumsy way of raising the price, with the kind of overshoot felt in 1979-81.

* * *

What should be done to cope with this instability is another question. Pent-up forces often work with violence. The world oil monopoly is both the largest of all time, and also the greatest in the divergence of price from long-run marginal cost. The accumulated tension between actual and competitive market conditions is therefore unprecedented.

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TABLE I
DEVELOPMENT & OPERATING COST, OFFSHORE U.K., 1983-84

		1982	1983	1984
1	OUTPUT MTY	100.1	110.5	120.8
2	OUTPUT MBD	2.029	2.240	2.449
3	RESERVES (MMBRLS)	7237	6845	5920
4	ANNUAL DEPLETION/DECLINE	0.102	0.119	0.151
5	LOST CAPACITY MBD	- -	0.248	0.331
6	GROSS GAIN MBD	- -	0.459	0.540
7	DEVELOPMENT IN-VESTMENT, $MM	- -	2727	2862
8	Do., $/IDB	- -	5937	5300
9	DEVELOPMENT COST, $/BRL	- -	4.57	4.43
10	PRODUCING OUTLAYS ($MM)	- -	1863	2135
11	OPERATING COST ($/BRL)	- -	2.28	2.39
12	DEVELOPING PLUS OPERATING COST ($/BRL)	- -	6.85	6.82

SOURCE:
U. K. Department of Energy. Development of the Oil & Gas Resources of the United Kingdom 1985 (HMSO 1985) and ibid (1984).
Output: Appendix 8, p. 68
Capital expenditures: Appendix 14, p. 77
Operating expenditures: Appendix 14, p. 78
Sterling converted at $1.50
Discount rate at 17 percent nominal
Tonne=7.4 barrels

Lost output is equal to current year output multiplied by average ratio production/reserves, given year and preceding year. Gross gain is sum of lost output and net increase.
Discount rate taken as 16 percent nominal on development projects. Assumes investor has access to U. S. capital markets. Rate is sum of 8.0 percent riskless end-1985, and 8.0 percent risk premium on oil and gas operations. The riskless rate will probably decrease because of lowered inflation expectations, and the risk premium may increase because of the perceived greater uncertainty of oil prices.

TABLE II
DEVELOPMENT & OPERATING COST, USA, 1984

DEVELOPMENT OUTLAYS ($MM)	GROSS RESERVES ADDED (MM BRLS)	DEVELOPMENT COST PER BARREL IN GROUND ($)	DEPLETION/ DECLINE RATE	RATIO ABOVE- TO IN-GROUND VALUE	DEVELOP- MENT COST AS PRODUCED ($)
14174	3748	3.78	0.115	2.39	9.04

------------------------1 9 8 2				----------------------	1 9 8 4
OPERATING OUTLAYS ($MM)	OIL FRACTION	OIL OPERA- TING OUTLAYS ($MM)	PRODUCTION MM BRLS	OPERATING COST/BRL ($)	ESTIMATE
17453	0.674	11762	2432	4.84	3.87

SOURCES:

DEVELOPMENT: Outlays, Census, Annual Survey of Oil & Gas 1982 adjusted to 1984 by Joint Association Survey.
Gross reserves added, DOE/EIA
Depletion/decline rate, ratio of production to average annual proved reserves, per DOE/EIA.
Ratio = (1+(i/a)), where i=discount rate, taken at 16 percent, and a=depletion/decline rate.

OPERATING: U. S. Bureau of the Census, Annual Survey of Oil & Gas 1
Production and expenditures are for the sample of compan
Oil fraction calculated by taking ratio of oil wells to wells, and assuming gas wells cost one-third more.
Reduced by 20 percent to reflect lower costs. See Independent Petroleum Association of America, Report of Study Committee, May (judgmental estimate), showing much larger decline for drilling expenditures.

TABLE III
DEVELOPMENT-OPERATING COSTS IN OPEC NATIONS
(1978 conditions, adjusted to 1985 drilling costs)

		Iraq	(1980)* Kuwait	Qatar	S. Arabia
1	WELLS DRILLED	42	36	32	145
2	APPROX. AVG. DEPTH (Tft)	9.238	2.156	7.046	5.661
3a	1985 AVG. COST/WELL ($MM)	0.571	0.069	0.337	0.238
3b	Do., adjusted	0.571	0.069	0.367	0.251
3c	Adjustment class			a	a
4	INVESTMENT ($MM)	40	4	19	60
5	OUTPUT, TBD	2593	1894	484	8066
6	OPERATING WELLS	197	545	102	700
7a	AVERAGE, TBD/WELL	13.162	3.475	4.745	11.523
7b	WTD. AVG. TBD/WELL ***	19.093 **	3.889 **	9.679	11.168
8	OIL WELLS DRILLED	36	24	12	46
9a	NEW CAPACITY, TBD	474	83	57	530
9b	ADJ. NEW CAPACITY, TBD	687	93	116	514
10a	INVESTMENT/BD (T$) =COST PER BARREL ($)	0.084	0.049	0.342	0.114
10b	ADJ. INVST./BD (T$) =COST PER BARREL ($)	0.058	0.044	0.168	0.118
11	SUPPLY PRICE ($/BRL)	0.145	0.110	0.419	0.294
12	1978 CAPACITY, MBD	4	3	0.65	12
13	1978 RESERVES, BB	32.1	66.2	4	165.7
14	1985 RESERVES, BB	44.1	89.8	3.3	168.8
15	1995 POTENTIAL (5%), MBD	6.0	12.3	0.5	23.1
16	CUMULATIVE POTENTIAL, MB	6	18	19	42
17	1995 INVESTMENT/BD (T$) =COST PER BARREL ($)	0.159	0.334	0.353	0.556

TABLE III (cont.)

		Indonesia	Libya	Iran	Algeria
1	WELLS DRILLED	499	175	112	177
2	APPROX. AVG. DEPTH (Tft)	5.301	6.698	9.800	8.853
3a	1985 AVG. COST/WELL ($MM)	0.212	0.312	0.637	0.527
3b	Do., adjusted	0.224	0.312	1.033	0.527
3c	Adjustment class	a		a,b	
4	INVESTMENT ($MM)	186	91	192	155
5	OUTPUT, TBD	1630	1983	5149	1164
6	OPERATING WELLS	3042	1113	445	1057
7a	AVERAGE, TBD/WELL	0.536	1.782	11.571	1.101
7b	WTD. AVG. TBD/WELL ***	1.902	3.515	16.853	1.736
8	OIL WELLS DRILLED	334	134	49	105
9a	NEW CAPACITY, TBD	179	239	567	116
9b	ADJ. NEW CAPACITY, TBD	635	471	826	182
10a	INVESTMENT/BD (T$) =COST PER BARREL ($)	1.037	0.380	0.339	1.339
10b	ADJ. INVST./BD (T$) =COST PER BARREL ($)	0.292	0.192	0.233	0.849
11	SUPPLY PRICE ($/BRL)	0.731	0.481	0.581	2.124
12	1978 CAPACITY, MBD	1.8	2.5	7	1.2
13	1978 RESERVES, BB	10.2	24.3	59	6.3
14	1985 RESERVES, BB	8.5	21.3	47.9	8.8
15	1995 POTENTIAL (5%), MBD	1.2	2.9	6.6	1.2
16	CUMULATIVE POTENTIAL, MB	43	46	53	54
17	1995 INVESTMENT/BD (T$) =COST PER BARREL ($)	0.567	0.641	0.671	1.527

TABLE III (cont.)

		Abu Dhabi	Venezuela	Nigeria
1	WELLS DRILLED	61	807	68
2	APPROX. AVG. DEPTH (Tft)	8.849	5.353	9.667
3a	1985 AVG. COST/WELL ($MM)	0.526	0.216	0.621
3b	Do., adjusted	0.577	0.228	1.008
3c	Adjustment class	a	a	a,b
4	INVESTMENT ($MM)	58	305	114
5	OUTPUT, TBD	1446	2166	1905
6	OPERATING WELLS	257	11333	1404
7a	AVERAGE, TBD/WELL	5.626	0.191	1.357
7b	WTD. AVG. TBD/WELL ***	6.487 **	0.330	1.725
8	OIL WELLS DRILLED	17	598	33
9a	NEW CAPACITY, TBD	96	114	45
9b	ADJ. NEW CAPACITY, TBD	110	197	57
10a	INVESTMENT/BD (T$) =COST PER BARREL ($)	0.611	2.673	2.540
10b	ADJ. INVST./BD (T$) =COST PER BARREL ($)	0.530	1.548	1.998
11	SUPPLY PRICE ($/BRL)	1.325	3.870	4.995
12	1978 CAPACITY, MBD	2.1	2.4	2.5
13	1978 RESERVES, BB	30	18	18.2
14	1985 RESERVES, BB	31	25.6	16.6
15	1995 POTENTIAL (5%), MBD	4.2	3.5	2.3
16	CUMULATIVE POTENTIAL, MB	58	62	64
17	1995 INVESTMENT/BD (T$) =COST PER BARREL ($)	2.592	3.976	4.982

TABLE III, NOTES AND SOURCES

NOTES: (1) The "2.5" adjustment (line 11) assumes a highly skewed distribution of well efficiencies and costs, as is true of an area with a very large number of mostly very small wells. It is a substantial overstatment for other parts of the world.

(2) It is assumed that the cost per unit is proportional to the depletion rate. This is usually though not always an overstatment. Reservoir development should aim to stop well short of the point where costs go non-linear.

* No oil well drilled in Kuwait in 1978-79.

** We use data on individual fields' productions for 1975, 1977, and 1977 to calculate the weighted average daily outputs for Iraq, Kuwait, and Abu Dhabi respectively. Due to this, the results are then adjusted to 1978 production condition.

*** In the calculation of the weighted average daily output per well, data on individual fields' productions are taken from the first six months of 1978. For any country whose total number of oil fields is less than 15, we calculate the wtd. avg. daily output for all the nation' wells. Otherwise, we only use the number of wells from its major oil fields in our calculation.

SOURCE: Wells drilled: "World Oil", annual International Outlook issue, August 15, 1979.
Nigeria and Abu Dhabi "suspended" wells estimated at worldwide percentage.

Well depth: same source, total footage divided by completions.

Daily output: same source.

Operating wells: same source, included both types: flowing and artificial lift wells.

Drilling cost: DOE/EIA, Indexes and Estimates of Domestic Well Drilling Costs 1984 & 1985 (DOE/EIA-0347(84-85)). These are exclusively onshore wells. Adjustment a is average ratio of total U.S. to onshore U.S. cost for given well depth, from 1984 Joint Association Survey. Adjustment b is ratio of maximum to average composite drilling cost for given depth, from DOE/EIA, op. cit.

Adjustment for non-drilling costs: Bureau of the Census, Annual Survey of Oil & Gas (discontinued after 1982).

Output of newly drilled wells assumed equal to average flow of existing wells.

Capacity from Petroleum Intelligence Weekly, April 9, 1979.

Year-end reserves from Oil & Gas Journal, issues of December 1978 and 1985.

Weighted average output per well using data from O & G J, December 25, 1978, and from International petroleum Encyclopedia, 1976, 1978, and 1979.

Potential defined as a 5 percent depletion rate of reserves as estimated by O & G J. Industry rule of thumb is one-fifteenth, or 6.67 percent.

Decline assumed as percent production is of reserves. Subtracting it from gross new capacity installed (above, line 9) implies a net capacity increase of 5.6 percent for 1978.

TABLE IIIa
DEVELOPMENT-OPERATING COSTS
of Oil Fields in Comalcalco and in Gulf of Campeche, Mexico
(1984 conditions and drilling costs)

		Comalcalco	Gulf of Campeche
1	WELLS DRILLED	45	35
2	APPROX. AVG. DEPTH (Tft)	17.286	12.622
3a	1984 AVG. COST/WELL ($MM)	3.697	4.291
3b	Do., adjusted	3.697	4.291
3c	Adjustment class		
4	INVESTMENT ($MM)	276	249
5	OUTPUT, TBD	721	1738
6	OPERATING WELLS **	357	100
7a	AVERAGE, TBD/WELL	2.020	17.380
7b	WTD. AVG. TBD/WELL ***	5.765	18.333
8	OIL WELLS DRILLED	30	27
9a	NEW CAPACITY, TBD	61	469
9b	ADJ. NEW CAPACITY, TBD	173	495
10a	INVESTMENT/BD (T$) =COST PER BARREL ($)	4.558	0.531
10b	ADJ. INVST./BD (T$) =COST PER BARREL ($)	1.597	0.504
11	SUPPLY PRICE ($/BRL)	3.992	1.259
12	1984 CAPACITY, TBD	721	1738
13	1984 YEAR-END RESERVES, BB	9.3	31.8
14	1995 POTENTIAL (5%), MBD	1.28	4.36
15	CUMULATIVE POTENTIAL, MB	1.28	5.64
16	1995 INVESTMENT/BD (T$) =COST PER BARREL ($)	7.071	3.158

TABLE 3a NOTES AND SOURCES (in addition to Table III)

NOTE: ** Data on the numbers of operating wells are as of July 1, 1984.
There are 249 flowing and 108 artificial lift wells in Comalcalco area and 100 flowing and zero artificial lift wells in Campeche area.

*** In the calculation of the weighted average daily production per well, data on individual fields' daily productions are taken from the first six months of 1984.

SOURCES: Wells drilled: "Memoria de Labores, 1984", [1985, Instituto Mexicano del Petroleo].

Well depths: same source, total footage divided by completions.

Daily output: same source.

1984 year-end reserves: same source, included 5 BB condensate in both areas.

Drilling cost: 1984 Joint Association Survey.
Since wells in each region are either all onshore or all offshore, no adjustment is necessary. We use the data on average drilling cost in the U.S. for given depth in the calculations.

Operating wells: Oil & Gas Journal, December 31, 1984 issue, annual report on worldwide production.

Weighted average output per well using data from the same source.

Capacity assumed equal to production.

TABLE IV

ZERO DRILLING AND RESERVE-ADDITIONS MODEL, 1985-95

	PRODUCTION (MBD)		------(BILLIONS OF BARRELS)------ CUMULATIVE PRODUCTION		PROVED RESERVES	
YEAR	CARTEL	NONCARTEL	CARTEL	NONCARTEL	CARTEL	NONCARTEL
1985	18	21	- -	- -	460	159
1995	54	9	144	58	378	39
1995 PRODUCTION:RESERVES ----------------------->					0.052	0.088

SOURCE: 1985,Oil & Gas Journal, "World Wide Oil"
Cartel includes OPEC nations plus Mexico
Non-cartel includes all others outside Communist blocks.
For explanation of 1995 values, see text.

FIGURE I

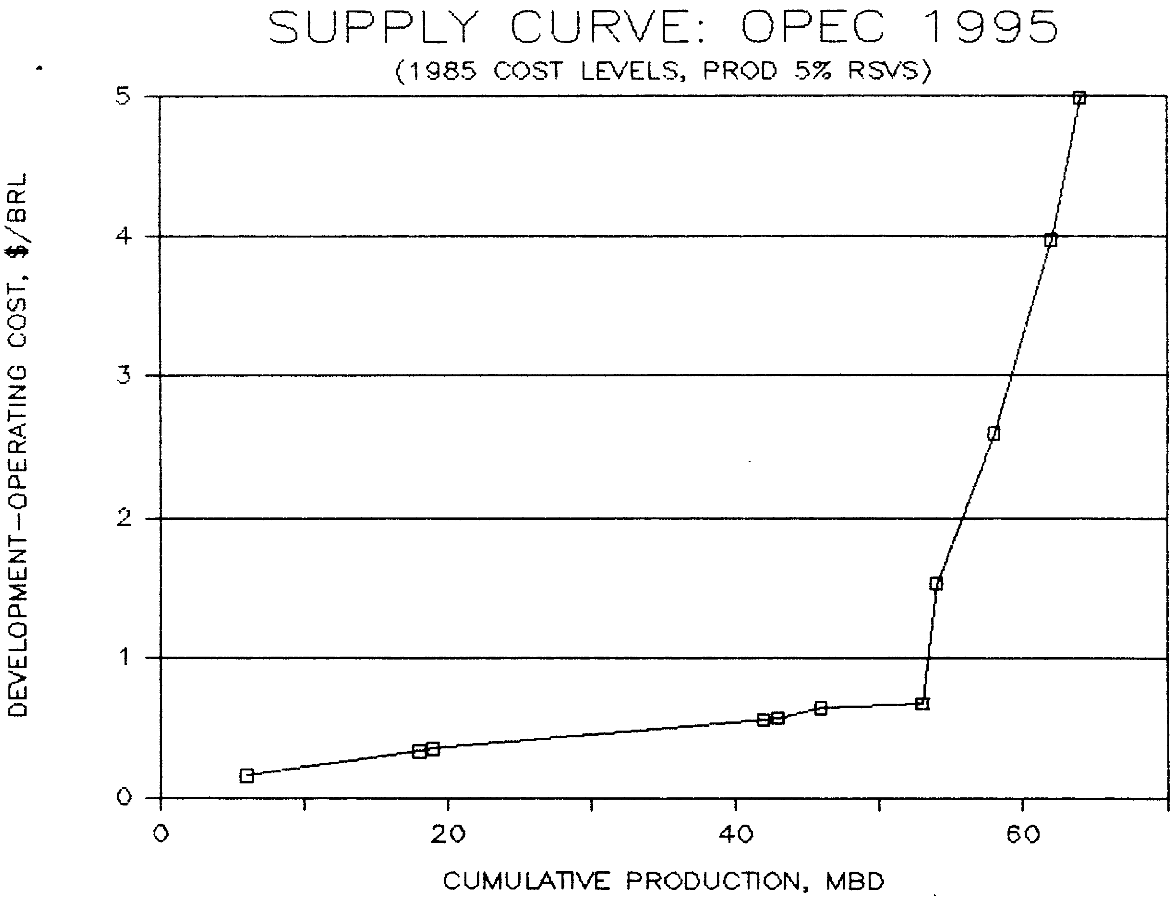
SUPPLY CURVE: OPEC 1995
(1985 COST LEVELS, PROD 5% RSVS)
DEVELOPMENT-OPERATING COST, $/BRL
0
1
2
3
4
5
0
20
40
60
CUMULATIVE PRODUCTION, MBD

TABLE III, NOTES AND SOURCES

NOTES. (1) The "0.5" adjustment (line 11) assumes a highly skewed distribution of well efficiencies and costs, as is true of an area with a very large number of mostly very small wells. It is a substantial overstatement for other parts of the world.

(2) It is assumed that the cost per unit is proportional to the depletion rate. This is usually though not always an overstatement. Reservoir development should aim to stop well short of the point where costs go non-linear.

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** We use data on individual fields' productions for 1975, 1977, and 1977 to calculate the weighted average daily outputs for Iraq, Kuwait, and Abu Dhabi respectively. Due to this, the results are then adjusted to 1979 production condition.

*** In the calculation of the weighted average daily output per well, data on individual fields' productions are taken from the first six months of 1979. For any country whose total number of oil fields is less than 15, we calculate the wtd. avg. daily output for all the nation' wells. Otherwise, we only use the number of wells from its major oil fields in our calculation.

SOURCE:

Wells drilled: "World Oil", annual International Outlook issue, August 15, 1979.
Nigeria and Abu Dhabi "suspended" wells estimated at worldwide percentage.

Well depths same source, total footage divided by completions.

Daily output: same source.

Operating wells: same source, included both types: flowing and artificial lift wells.

Drilling cost: DOE/EIA, Indexes and Estimates of Domestic Well Drilling Costs 1984 & 1985 (DOE/EIA-0347(84-85)). These are exclusively onshore wells. Adjustment a is average ratio of total U.S. to onshore U.S. cost for given well depth, from 1984 Joint Association Survey. Adjustment b is ratio of maximum to average composite drilling cost for given depth, from DOE/EIA, op. cit.

Adjustment for non drilling costs: Bureau of the Census, Annual Survey of Oil & Gas (discontinued after 1982).

Output of newly drilled wells assumed equal to average flow of existing wells.

Capacity from Petroleum Intelligence Weekly, April 9, 1979.

Year-end reserves from Oil & Gas Journal, issues of December 1978 and 1993.

Weighted average output per well using data from O & G J, December 25, 1978, and from International Petroleum Encyclopedia, 1976, 1977, and 1979.

Potential defined as a 5 percent depletion rate of reserves as estimated by O & G J. Industry rule of thumb is one-fifteenth, or 6.67 percent.

Decline assumed as percent production of reserves. Subtracting it from gross new capacity installed (above, line 9) implies a net capacity increase of 5.6 percent for 1979.