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Reserve Prices and Mineral Resource Theory*

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SURVIVOR'S NOTE. Gordon Campbell Watkins was my friend for forty years. He freed me, as the Scots poet says, from many a blunder and foolish notion. We joined forces twenty years ago, when the basic data on hydrocarbon scarcity were starting to disappear. (Adelman and Watkins, 1996). A revised updated version was given in 2002 at an IAEE session in Prague. The last paper of our last effort follows, delayed by his death and my ailments.

We are indebted to the Center for Energy and Environmental Policy Research at MIT for continuing aid. Without Therese Henderson and Jeanette Ehrman, the work could not have been completed. Errors in this final revision are mine alone.

M. A. Adelman

1. MINERAL VALUES AND LIMITED RESOURCES

Many recent books and articles predict a looming decline and end to oil production, and ever-rising prices. Typically, half the original endowment has already been produced; annual production "must" soon decline. (E. g., the head of the Institute of Petroleum (London) in *Oil & Gas Journal*, March 3, 2003, p. 28)

We have heard this often since 1875. (Chernow, 1998, pp. 102,197). The production of oil has since grown a thousand fold. Estimated reserves and resources have massively increased. But the theory of oil exhaustion is unchanged: the Earth is finite. Hence any subset, including any mineral, is also finite. At *any* rate of consumption it must finally disappear. Moreover, once production begins, pressure falls and production with it. Pennsylvania output peaked in 1890, Texas in 1970, and so on.

Doomsday forecasts were popular in the 1970s, and even more so today. Simply subtract forecast production/consumption from estimated resources.

The Energy Journal, Special Issue to Acknowledge the Contribution of Campbell Watkins to Energy Economics.

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Whether the latter are "pessimistic" or "cornucopian" makes only a small difference in the remaining time to catastrophe.

Because of panic over oil exhaustion in 1970-80, public money was wasted to provide oil alternatives. The price of oil, inflation-adjusted, is now (start 2006) about the same as 1980, but the panic seems greater, and probably the waste will be.

Worldwide oil prices are said to have risen since 1973 because of an excess of demand over supply. Yet OPEC output, which is cheapest,[1] has been unchanged since 1973¸ and OPEC exports have fallen. In 1999-2006, there were repeated downward OPEC quota revisions. Crude oil in their judgment was (and is) too plentiful. Output had to be cut lest prices suffer.

Non-OPEC countries are competitors, who never have excess capacity, but produce all they can. Over time, they have kept increasing capacity and output, some tailing off as others grow. But OPEC, with far lower investment and operating costs, has actually reduced exports. Thus in the world industry for over 30 years water has kept flowing uphill: contraction in lower-cost areas, expansion in higher-cost countries. Only a profit-maximizing cartel of low-cost producers can explain the fact.[2]

The OPEC nations, like sensible monopolies with incomplete information, must feel their way into the market. Their announced target price was at first $18-$21, then successively higher, up to the current (mid-2005) $60-odd. It will go higher, if they think it advantageous. Despite excess capacity, no member will offer more oil at a lower price. It would benefit the individual seller, but not the group; solidarity demands the price-cost signal not be heeded.

The price will cease to rise when OPEC finds it unprofitable to keep raising, or when it becomes too difficult for OPEC to keep its output equal to the amount demanded at the current price. We offer no guess when this will happen. But the current price level has no relation to excess demand, nor to alleged or assumed resource inadequacy, of which there is no evidence.

Our own theory of resource scarcity is simple: "There is an endless tug-of-war between diminishing returns and increasing knowledge." (Adelman, 1990, p.1). Neither in 1875 nor today can anyone estimate ultimate mineral resources, nor the amount of oil nor the time of remaining production.

1. Every oil producer must cope with production decline, and must invest even to maintain the level of output, let alone raise it. Even stable output implies positive investment, and the cost of increased output, marginal cost, exceeds average cost. See below, page 14, on Saudi Arabian investment per barrel.

2. Since OPEC seeks the profit-maximizing price for crude oil, consuming countries, especially the USA, can levy excise taxes to divert the industry's revenues, now several hundred billion dollars annually, to themselves. It would be no additional net burden on consumers, who would in any case pay the maximum-profit price. Thus consuming countries' power at the ultimate level, the consumer, would trump OPEC power over supply. They could offset part of the burden by special taxes, but that is a separate question. No such action is to be expected soon.

The Jevons Coal Study

In his pioneer if incomplete study of British coal, W.S. Jevons (reprint, 1965) analyzed flows not stocks. Scarcity in any market was expressed by the price, at the meeting point of the schedules of supply and demand. The supply curve at any point was the cost of more output. A mineral industry then as now faced an upward sloping curve. As the cheapest portion of the resource is used up first, the leftmost section of the curve disappears, and marginal cost increases. British coal, in Jevons' view, was exploiting ever more costly seams, requiring ever-higher prices. Those prices not exhaustion would eventually choke off greater use and output.

British coal output did indeed fall, after 1913. What little coal persists in Europe today is largely subsidized. But there was never any resource exhaustion. Billions of tons remain in ground to this day, untouched because current investment and extraction costs are too far above the price, set by natural gas, nuclear power, and foreign coal and oil. Jevons' forecast omitted something that happened over time. We seek it now.

Hotelling and Depletable Resource Theory

Economists have long recognized that future events cast their shadows into the present. Any future value must be discounted down to the present in order to be comparable to any current price. But a "depletable" resource stock, limited by nature and doomed to decline, is special. Even a low rate of consumption would constantly reduce the amount, and raise the value, of what is left in the ground. The theory of this special case was worked out in the classic paper of Hotelling (1931). He proved that in a competitive industry, each unit of the stock must at any moment have the same present value as any other unit. Arbitrage would erase any difference. Therefore the value of any unit of the stock must increase at the rate of return earned on the whole stock. Moreover, the present value of any particular unit is independent of how soon that unit is brought up and sold.

Three testable hypotheses were implied. H1: At any moment, the value of a unit in-ground equals its gross field price less the current outlays needed to lift it from below-ground to the surface. H2: This in-ground net unit value must increase at a rate equal to the return to holding other assets of similar risk. H3: At any given moment, the rate at which a given deposit is exhausted has no effect on its unit value. The price allows for this by rising at the economy-wide rate of discount.

In 1931, there were no empirical data to confirm or refute the paradigm of constantly increasing *net* in-ground value. Changes in *gross* spot prices, of the mineral emerging from the earth, were the first object of study. Potter and Chrystie (1962) showed that gross minerals prices had if anything decreased over the long run. Other such studies later appeared. Tilton (2003, chapter 4) summarized: there has apparently been no general increase in the gross prices of minerals generally, but it is difficult to deflate any price series to get changes in real scarcity. We share his caution. But if the Hotelling paradigm is correct, then all minerals in situ must constantly grow more scarce and valuable. We ought to be reminded of this basic truth by the history of most minerals, instead of by few or none of them.

Gordon (1967) was the first to question directly the Hotelling paradigm of rising values and net prices. Mineral industries were not behaving as they "should." Adelman (1970) doubted any distinction between mineral and non-mineral industries. But particularly after the oil price explosions in 1973-80, economic opinion ran strongly the other way. (Solow 1974; Stiglitz, 1976; DasGupta & Heal, 1979; Gately, 1984; Miller & Upton 1985; Arrow, 1987). Often invoking Hotelling, they and others considered the oil price increases as the necessary effect of limited non-renewable resources. Some predicted oil prices above $100 per barrel, before the year 2000. In fact, the inflation-adjusted price fell after 1980, was stable in 1985-1998, and has now regained the 1980 peak; $100 is again forecast, by 2010. (*Oil Market Intelligence*, December 2005, p. 1) The repeated refrain—"*this* time the wolf is here"—makes us question the theme.

2. IMPLICATIONS OF DATA ON NORTH AMERICAN OIL AND GAS RESERVE VALUES:

(a) Industry Practice

In the USA, there have long been many sales of in-ground oil and gas. The industry's working 'rule' or approximation has been: in-ground reserve sales value is about one third the gross field price. However, the *net* field price has been around 0.65 of gross, in a quite stable proportion (Census ASOG 1972-1982, API 1983-1991). Hence the adjusted field price is double not triple the reserve value.

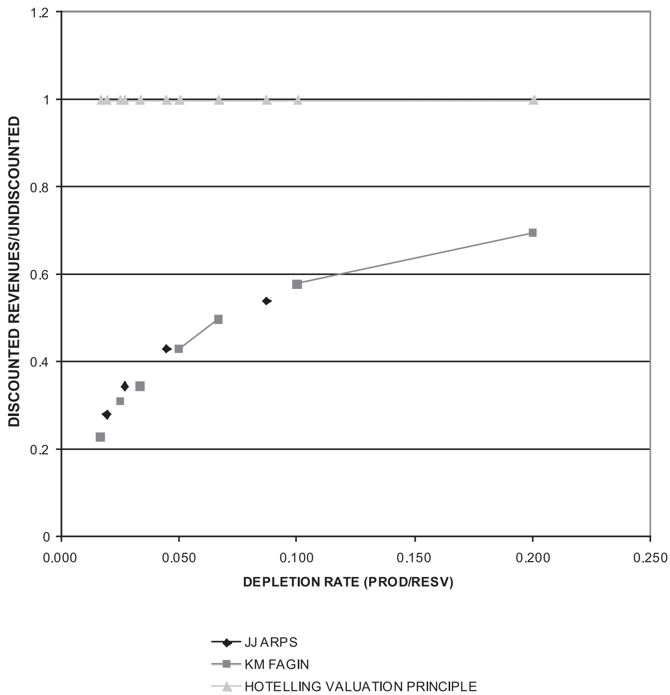
Some studies by engineers in the 1950s confirmed the industry's working approximation of reserve values as one-third gross prices (half of net prices). They also showed that the more quickly the reserve was to be exhausted (i.e. the greater the ratio of current output to reserves) the greater was the reserve's market value in relation to the current field price. (Bradley, ed. 1987, chs 40-41) (See Figure 1, constructed from it.)

Thus industry practice was (and is) in conflict with two Hotelling paradigms: H1 and H3. Net in-ground values were on average only half (or in the industry paradigm one-third) of predicted values. And the nearer in time the given barrel was scheduled to be drawn out of the earth, the higher its present value. This follows from a positive interest rate. But according to the Hotelling valuation principle the value equals the field price.

(b) Estimated Reserve Value and Net Price

Starting with 1946, the per-barrel values of in-ground oil and gas reserves were estimated by the John S. Herold Company for many individual producing

Figure 1. Reserve Present Value as Function of Depletion Rate



companies. Their methods of valuation remain unexplained. A study of them (Adelman DeSilva & Koehn, 1991) was done for 1948-1986 (omitting 1946-47, when the samples were too small). In every year, the average net field price exceeded the annual average in-ground value plus at least one standard deviation. In 32 of the 37 years, the net field price exceeded the average reserve value by two or more standard deviations.

Watkins (1992) who found similar results for Canada, asked how the industry could thus ignore what seemed like a basic (and favorable) rule: that the in-ground value equaled the net price, and must rise at the current discount rate. He thought economists should not ignore what industry was actually doing.

Adelman & Watkins (1996, 2005) constructed a new independent data set from publicly known and tabulated sales of reserve-bearing properties. The reserve values in situ were defined as the sales values of the properties sold divided by the corresponding amounts of reserves sold. Average value in situ per barrel or per mcf was always below the net field price and rarely within one standard deviation of it. Moreover, Adelman & Watkins (2005 at 567) show the oil reserve values, of oil and more strongly of gas, are directly related to R/P ratios.

Interpretation

Thus the Hotelling paradigms conflict with the industry data, and with ours. There are three possible explanations. First: errors of observation and calculation. In rejecting this, we obviously are not altogether impartial. But we have had no part in constructing two of the three data sets. Our own, based on publicly available sources, is derived and calculated independently of the others. Moreover, we define and calculate measures of dispersion, to reckon the odds against the Hotelling paradigm being correct.

The second interpretation is that Hotelling's theory is wrong. This is very unlikely. He was an accomplished mathematician. For seventy years his theory has been studied by many skilled observers, ready or eager to find mistakes.

The third possibility: the calculations and the Hotelling theory are both correct. The conclusions do follow strictly from the premise of a limited known in-ground stock. Since the conclusions are empirically false, and are implied by the premise, that premise must itself be empirically false. There is no such thing as "the fixed stock of oil to divide between two [or more] periods." (Stiglitz, 1976). What then are the various types of reserves, including "proved reserves"?

3. MEANING AND VALUATION OF "PROVED RESERVES"

Proved reserves are *inventory*. They are defined and explained in the engineering handbooks (Frick 1962, Bradley 1987) as the end-product of development investment. A well is considered when enough is known about the reservoir to allow investors to bet on a prediction: it will produce a given amount in the initial year, declining each following year at a roughly constant percentage rate.

As production declines, current expense rises per unit of output. The margin shrinks between gross value of output and current outlays. When the margin goes to zero, this is what the industry calls the "economic limit". Production stops. The un-produced oil or gas still in the ground is not counted in reserves because it is not worth producing. The industry's practice is to disregard stocks and reckon only with flows.

Whether a proposed well or wells will be undertaken, and additional reserves created, depends on the present value of estimated future revenues versus current investment costs. If the proposed output's net present value (i.e., net of operating cost) is less than the required investment, the well is not drilled and no new reserves are created. If delay in drilling would increase a well's present value, drilling will be delayed. Either way, there is no creation of reserves, but there is a creation of *option value*.

Following finance theory, we define the option value of a deposit as equal to its value as a developed reserve *minus* the development cost which must be incurred to realize the value. (Paddock Siegel & Smith, 1988). Option values are created by discovery—of oil, of knowledge, or both.

Exploration outlays are therefore an advance fee for development rights, or a way of making more exact the opportunities for development. Either way there is greater knowledge: the question is whether development rights turn out to be worth using. A company does not know what if anything it will get in return for any particular exploration outlay.

The more exploration, in relation to development, the more risky is a company's activity, and the higher is the threshold rate of return. Exploration cost is the higher threshold rate of return it must allow per dollar of investment.

Exploration in new areas normally reflects this fact and carries with it the right to develop. In the 1970s, Iraq (already effectively under Saddam Hussein) welcomed three oil companies from three foreign countries, who found three new fields—which were then given to the national company for development. As a result, Iraq vainly sought foreign investment in 1990. In neighboring Iran, the government in 2004 introduced a bill in parliament granting foreign oil companies the automatic right to develop discoveries. Parliament refused to pass it. [PIW 9-13-04:4] This was consistent with the decades-long policy, which had the usual effect of limiting investment and production.

Thus a proved reserve is: the estimated cumulative production from currently installed capacity, as calculated by engineers and accepted by investors. If the well is drilled, let Q be the reservoir's initial output, continuing until time T. In a reservoir, or for all pools in an area, the reserve is graphed as the area under the production curve:

$$R = \int_0^T Qe^{-at}\,dt \qquad (1)$$

If the limit T were infinite, we would have:

$$a=Q/R \qquad (2a)$$

Since T is less than infinite, we reason that the higher is the initial decline rate, the shorter the decline toward zero, and we approximate:

$$a=Q/R - (Q/R)^2 \qquad (2)$$

i.e. the annual decline rate approaches, but is slightly less than, initial output divided by the reserve. We use the following approximation:

$$V = Pa/(a+i-g) \qquad (3)$$

Moreover, since all variables but *g* are exogenous one can calculate:

$$g = i + a[1-P/V]$$

The variable g measures the expectations of future prices. As might be expected, observed annual g is highly variable. We need to measure its standard error. (Adelman and Watkins 2005)

An assumption alternative to (3) is probably more realistic. Assume that firms do not try to compute price change over time, but instead reckon a one-time change the next year. If so, we equate g to zero, and write:

$$P' = V\,(a+i)\,/\,a \qquad \text{(3a)}$$

P' is the industry "planning price". The other variables are unchanged:
V=the reserve value;
P=the current field price; P'=the planning price;
a=the adjusted (see 2a) annual production decline rate;
i=the discount rate on future production revenues;
g=the expected annual increase in the net price *P*.

Assume that $i>g$, hence $(i\text{-}g)$ is positive. Then V/P should be an increasing function of '*a*', at a decreasing rate. So it is in the engineering studies underlying Figure 1 (Bradley¸ 1987). Further confirmation is at (Adelman and Watkins 2005, p. 567), which shows a positive relation between reserve value and speed of recovery, i.e., an increase in the ratio Q/R.

Equations (3) and (3a) contain the same basic variables as the Hotelling paradigm, but partly different concepts. Hotelling assumed that R is exogenous, fixed by nature. In our usage, however, R is a variable, the cumulative oil or gas to be produced, at a diminishing rate, from facilities created by investment. The longer the buyer must wait, the less is the present value of this future production revenue. We also treat R as a stochastic variable, and calculate its variance.

On some crucial assumptions, the two systems are identical. Let net price rise at the discount rate, *i*. Then $g = i$, and Equation (3) collapses to V = P. This is the Hotelling paradigm. Or, if we could establish by independent evidence that $V=P$, then $g=i$.

Like many assets, a given R may be exploited or sold. These uses are competing substitutes, therefore so are their prices. Where the decision is not to develop, the value of R is only its option value, i.e., sales value of the mineral *minus* its development cost.

National "proved reserves" are simply the national total of R. In the USA after 1918 the number was compiled and published by trade associations. The US Government assumed the task in 1980, but published national totals were hardly affected.

Oil or gas in "non-producing reservoirs" is not counted in the US official totals of proved reserves, and should not be. These reservoirs are an interim or transitory class: "those waiting for well workovers, drilling additional development or replacement wells, installing production or pipeline facilities, and awaiting…recompletion in reservoirs not currently open to production." (*U.S. Crude*

Oil, Natural Gas, and Natural Gas Liquids Reserves, 2000 Annual Report, December 2001, p. 24). The amounts are excluded from the national reserve totals, until and unless the investment has been completed.

Outside a few countries, "proved reserves" have become a statistic of doubtful value. Some countries do not even bother to update them. They deteriorated rapidly in the Middle East after 1980. OPEC countries increased their published reserves greatly because of the fear or hope that future OPEC quotas might be tied to proved reserves. For example, Kuwait proved reserves, compiled by the government company, are 100 billion barrels. But they were recently [PIW 1-30-06:6] estimated by a Kuwait government task force at 48 billion, of which "roughly half" was proved. In 2005, Kuwait production was 0.84 billion barrels. If so, there is a check: the decline rate was a plausible 0.84/24.0, or 3.5 percent. The new reserve estimate still is subject to error, but far better than the old one.

Applying the correction to total Middle East reserves would decrease it from 243 to 50 billion barrels. This would simply undo past mistakes. It would imply nothing about reserves or their "adequacy," about the region, or the world market. (In fact, the biggest un-hatched chickens are in Canada: 170 billion barrels in undeveloped oil sands¸ against less than 5 billion in crude oil proved reserves.)

Non-OPEC production and proved reserves have both risen despite prevailing opinion in the 1970s, e.g., President Carter's, that they might go to zero by 1990. But even revised reserve totals do not convey any information about ultimate production of non-OPEC hydrocarbons. That amount is not only unknown today, it *is un-knowable* because it depends on future science and technology. Let us consider some instances.

Revisions of National Totals

In 1944 the firm of DeGolyer & MacNaughton estimated Middle East oil reserves at 16 billion barrels proved and 5 billion probable. By 1975, according to the *IPA (1975),* those same fields, i.e., found before 1944, had already produced 42 billion, and had another 75 billion in "proved reserves"; the fields contained not 16 but 117 billion. Much has been produced from those fields since 1975. We guess that their proved reserves are greater today, but the number is gone from the public record¸ along with much else. An iron curtain has fallen over much of the world oil industry.

The DeGolyer firm estimated from what was known in 1944 by geologists and engineers. Today they know much more.

The firm recently estimated the probable reserves of Russia as twice the previous estimate. One supporting assumption is that Russian oilmen can extract about 45 percent of the underground oil in place, half as much again as in the USA. Doubtless they can; whether or not they will depends on national policy, and on whether the development is public, private, or mixed. Recently the International Energy Agency said Russia would need to spend $900 billion to increase capacity by 1.5 million barrels daily (mbd), i.e., $600,000 per daily barrel. (NYT, 5-13-06:D3) If the Russians took this seriously, they would never waste resources to increase output.

Offshore

Before 1950, there was no offshore production or proved reserves. By 1975, offshore wells were being drilled in up to 1000 feet of water. This limit was set, apparently, by immutable physical and therefore economic relations. To go twice as deep took roughly ten times as much steel, mostly for the huge producing structures to be built in the water. But by the end of the century, wells were being drilled ten times as deep, in 10,000 feet of water. The limit had been displaced because engineers had devised methods of placing a well directly on the sea floor instead of building huge steel structures there. A bit later, there was use of previously classified US Navy data which permitted oilmen to "see" through salt sheets to oil-bearing structures underneath. Thus offshore proved reserves have grown from zero in 1950, and continue to grow, because of greater knowledge. Hence the deepwater Gulf of Mexico data records proved growth from year to year.

Company Estimates

The estimates of "proved reserves" published by oil companies have been discredited by the 2003 scandal over Royal Dutch/Shell reserves. Unfortunately, "reserves" are both economic geology, and also self-promotion in the securities market. It is an uneven match. The American industry long ago devised a prophylaxis: divide the task of reserve estimation among many local groups of geologists and engineers. Each group was responsible for a small area¸ and each group member pledged not to reveal any estimates or discussion to anyone but a fellow member of the committee, not including even his own company. The system never failed; but reserve computation became a public activity in 1980.

"Probable reserves" are estimated amounts of oil and gas that *would be* economic to produce at any moment, given current technology, and enough time to apply them in new investment. In the USA, 1995 proved reserves and probable reserves were respectively 26.8 and 141.9 billion barrels of liquids; and 135.1 and 1073.8 trillion cubic feet of natural gas. (U.S. Geological Survey, Circular 1118, *1995 National Assessment of US Oil and Gas Resources*.) Thus probable reserves were roughly 5 to 7 times as large as proved. Using a 10 percent decline rate for U.S. proved oil reserves, only about 35 percent would remain after ten years. Since crude oil reserves at the end of 2005 were, on the strict official definition, 21.4 billion (OGJ Dec 19, 2005, p. 22) it is evident that they were drawn out of the probable reserves of ten years earlier, or out of knowledge created later.

"Probable reserves" are a useful ordinal measure, permitting one to rank areas where discoveries of oil are more, or less, likely (Weeks 1969). But adding probable to proved reserves is senseless, if only because proved reserves are worth so much more per unit. In any case, a "peak oil" forecast assumes knowledge of the future or "ultimate" reserves, i.e., the total of all oil that will ever be produced. This ultimate amount is not uncertain or controversial. *It does not exist*.

Separate Treatment of Oil and Natural Gas

We make no attempt to reduce oil and gas to any "equivalent". There is none. The relative thermal content of crude oil and gas, as sold to final users, does not determine relative wellhead prices or values. Transport intervenes between wellhead and use, and gas is much more expensive to transport.

US crude oil production decreased from 9.2 mbd in 1973 to 5.9 mbd in 1999, since when it has been nearly constant: continued growth here, recession there. But USA natural gas production and proved reserves both grew through 2004, then stayed constant, while Canadian imports grew through 2005.

Oil price changes reflect worldwide oil price forecasts, including hopes of further price increases by the world cartel. For gas, reserve value changes reflect North American gas price expectations in a competitive market.[3] Over the period of our inquiry, price behavior in Canada has differed as between oil and gas. (G.C. Watkins & Andre Plourde, "Relationships between Upstream Prices of "Crude Oil and Natural Gas," Discussion Paper, University of Aberdeen, August 2000.) The differing price expectations reflect the fact of two different markets.

In the USA, prices have diverged, and investment behavior has differed greatly as between oil and gas. During 1980-2005, oil wells drilled *decreased* by 76 percent, but gas wells *increased* by 93 percent. (Total dry holes drilled, a rough inverse measure of efficiency for both, fell from 29 to 12 percent. [US Department of Energy, *Monthly Energy Review* April 2006, table 5.2])

4. RESERVE VALUES AS MARGINAL FINDING-DEVELOPMENT COSTS OF OIL AND NATURAL GAS

In a competitive industry, the value of a unit in-ground is equal to the value of the marginal reserve-added, i.e., to its marginal cost. Private or public restriction of the flow of capital into exploration/ development prevents this equalizing. Hence we must face the question of restriction, i.e., the lack of enough competition to bring about the result.

Restriction in the form of maximum field-price fixing was strong in the creation of natural gas reserves in the US and Canada before the 1980s, and it was not negligible for crude oil in 1946-80. Oil "prorationing", especially in Alberta and Texas, favored investment in high-cost wells. US Federal maximum price fixing in 1974-80 favored investment in high-cost "new" oil. But de-regulation of oil and natural gas in the 1980s abolished these constraints. They did not exist after 1982.

3. The emerging world market for LNG, with participation by North American firms, suggests that in time the market for natural gas will become a single world market. But it is not one yet.

There is some difficulty in using these data sets to represent long-run cost trends. Marginal costs are investment costs: more precisely the necessary return, comparable to investment returns in industries with similar degrees of risk. The value of oil reserves is set by competition in the worldwide market for hydrocarbon discovery and development. But part of this market is noncompetitive: in the OPEC countries, investment and output are limited to support field prices at levels fixed far above marginal costs. In the non-OPEC world, now about 60 percent of world production, and a much higher proportion of investment, there is a competitive investment response to the noncompetitive field price of oil.

Discovery Cost and Development Cost

In the non-OPEC areas, discovery and development activities together comprise a sensing-selection network, constantly seeking the cheapest reserve-additions of oil and/or gas.

Note that observed marginal costs depend on the position of a demand function. North American marginal costs may be – and we think are – associated with the supply functions moving leftward–i.e., unfavorably—at a time when demand has stayed constant or moved rightward. Hence a larger share of U.S. domestic consumption is supplied by imports. Rising marginal costs have made more North American oil output non-economic. (Bradley & Watkins, 1994; Adelman, 1998; Watkins & Streifel; 1998). It is a case similar to British coal, but less dramatic.

But the results are not compatible with statements that the absolute amount of worldwide discoveries has declined since the early 1960s. (E. g., International Energy Agency, *World Energy Outlook 1998*, especially pp. 90-100.) If discoveries had really declined since then, the newfound deposits would be smaller, deeper, and farther from market. Hence they would cost more to develop. But there is no evidence of rising development cost.

In fact: *there are no discovery statistics,* either of oil or gas. Changes in discovery rates are often asserted or assumed, but no one has explained how to calculate them, even in theory. To derive them from production, decades later, is circular. To count the number of newly listed fields or pools is trivial because a field definition changes as more is known about the constituent pools.

There are, to be sure, estimates of probable reserves as of any given year. We have already referred to the US Geological Survey. (U.S.G.S. Circular 1118, *1995 National Assessment of U.S. Oil and Gas Resources*, 1995). Undiscovered liquids expected to be found in new fields were estimated for 1995 at 37.5 billion barrels, and growth in known fields at 73.4 billion, in total 110.9 billion, or 5.4 times 1995 proved reserves. Natural gas totals were 1,073.8 billion cubic feet, or 8.0 times proved reserves. This was a plausible estimate at the moment it was made.

In the USA statistics, any given year's "discoveries" are a category of development: reserves developed during the year in newly found fields. In the next year and in all later years, their development will be in "old" fields.

If there were a fixed quantity of "ultimate reserves", then the greater the aggregate past output, the higher the marginal cost of new production. If so, then since 1946, marginal costs, and reserve values, simply *had* to keep rising. Buyers and sellers have always known better and have priced reserves accordingly.

Marginal Costs in Non-OPEC Areas

During ten years 1987-1996, the world price of crude oil touched a high of $21.13 (1990) and a low of $15.72 (1992). The mean was about $18 in current dollars, and $24 in dollars of 2005, using the U.S. Producer Price Index as a deflator. During this time, non-OPEC output stayed nearly constant around 38 mbd. This permits a rough estimate of non-OPEC marginal cost of around $24 per barrel in 2005 dollars.

Marginal Costs in OPEC Areas

This method cannot be applied to OPEC countries because the price has no relation to marginal cost. There is little or no authentic recent data for any part of the region. The lowest marginal costs are in the Persian Gulf areas. Below we calculate current marginal cost of Saudi Arabia at $3.35 per barrel, an overestimate because it makes no allowance for natural gas, and uses a cost of capital which is too high for development.

Were the OPEC countries independent competitors, they would increase investment and output and (probably) marginal cost. Hence average OPEC marginal costs might perhaps go as high as $10, as Parra suggests. [Francisco Parra (former OPEC Secretary-General), *Oil Politics: a Modern History of Petroleum*, 2004]. In any case, there is no suggestion of growing scarcity of the resource crude oil.

Around the Persian Gulf, for many years, nearly all new reserves have been created in old fields. Perhaps new fields have been sought, but not found. But trade journals show no such massive search, indeed not much evidence of any search. Another hypothesis is then more likely: that old fields have been the cheapest way to expand.

Another indicator going back in time: in 1976 Aramco agreed to pay Saudi Arabia 6 cents per barrel of newly discovered oil, as the oil was produced. This estimates option value, not marginal cost. Even using a low discount rate, the present option value of the undiscovered oil could not have exceeded 3 cents per barrel. Since prices have been from several hundred times to two thousand times as high, one must explain why there was not more discovery effort to find something so valuable.

A simple hypothesis fits the data: old-field expansion was so cheap for so long that no sensible owner would seek new fields.

There is another long-time perspective. In a large field developed over a long time, variations must be expected in rocks drilled and fluids produced. Usually, wells are drilled around the periphery of the field, following the oil-water contact as it is known. New wells might be drilled higher, hence fewer and cheaper. But they would also be less efficient in sweeping the periphery of the field. The tradeoff may change in time. As the engineers make the field grow in area and in fluids content, they learn more about it. To assume that a lower volume of fluid remains in the reservoir *because* the engineers are learning more about it, and publishing their work, seems like an obviously invalid inference. A well known example is (Matthew R. Simmons, *Twilight in the Desert,* Wiley, 2005).

Saudi Arabian Discovery-Development Investment & Cost, 2007-2012

According to [PIW, July 18, 2005, p. 7], Saudi Arabia plans to spend \$11.2 billion on development drilling over the five years 2007-2012. Assuming that as in the USA (above, page 7)¸ development drilling investment was about 65 percent of total investment in the USA, we divide by 0.65 to estimate total development investment at \$17.2 billion, over five years, which is about 7 percent of a single year's revenues.

Oil produced over the next five years is taken at five times the current 10 mbd. A decline rate of 4 percent [cf 2.9 percent at Adelman 1995, p. 260] means that the capacity loss made good by new development during the five years is a total of 2 million bd. Adding the 2.5 mbd capacity from new development projects means total new capacity installed was 2+2.5=4.5 mbd. Total development investment is then [\$17.2 billion/ 4.5billion] \$3,822 per daily barrel, or \$10.47 invested per annual barrel produced.

Current operating expenditures or "opex" (labor, power, etc.), are conventionally taken as 5 percent of "capex" (capital expenditures). But discounted and weighted, their present value is about 8 percent of the investment. (Ibid) Assuming the minimum corporate discount rate to be the long-term bond rate of 7.5 percent, we estimate the total discovery-development discount rate (above, p. 10) at 20.0 percent. This is an (excessive) allowance for more risky investment in discovery.

Summarizing: the threshold rate of return on Saudi development is 0.08+0.04+0.20= 0.32. The marginal cost of newly developed Saudi oil is then \$10.47*0.32 = \$3.35 per barrel, in 2007-2012 prices. Our estimate is too high because it includes natural gas, and too high a rate of return on a mixed discovery/development portfolio. Our best estimate is therefore \$3.35 *less* X.

5. CONCLUSIONS

The public perception is today gripped by the notion of limited stocks of oil in the ground. Only if we believe in such numbers is it reasonable to assume ever-rising prices or to ask how much is in "remaining reserves," how long will they last, how much in friendly or nationalist hands, what to do when the oil runs out, etc. But these amounts of ultimate reserves are not merely difficult to estimate—they do not exist. Public belief in them means more public money will be devoted to non-oil and other costly energies. Consuming-country governments will have an ever-bigger vested interest in higher oil prices.

In the real world, only flows exist, even in such "renewable" reserves as water. At any given moment, setting aside possible monopoly effects, the real cost of using increasing amounts of it must rise. For oil, the relevant cost statistic is the amount of investment needed per unit of new capacity. There have been no statistics on this for over 20 years. The belief that we have entered a new era of scarcity rests on endless repetition—plus inability to see market power.

Our research has been into the only stock that exists in the real world: the inventory of proved reserves, which is the forthcoming output from past development investment. Sales of such reserves provide examined, bargained-over amounts and values. These are the basis of our work. Proved reserves have no relation to future discoveries and development, depending on future science and technology, which nobody can tell.

At any moment, proved reserves determine productive capacity, the limit to current output. Investment has kept total non-OPEC capacity growing, about 60 percent since 1970; most non-OPEC countries are up, some down. But OPEC capacity has been static for lack of investment. Some OPEC countries have increased capacity, benefiting by others' losses from bad luck or bad management. To keep total OPEC output static is simply good management by those who can grow. Added output would depress prices and profits. Investment cost is very low in the OPEC countries, a small fraction of price, but it is more profitable to refrain from investing.

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