Chapter 5

Economic and Resource Factors Affecting U.S. Oil Production

The Profitability of New Investment in Oil Exploration, Development, and Production

Introduction

As noted previously, there is a basic disagreement among analysts of the oil industry about whether it is the prospective profits of new investments in exploration and development (E&D) activity or **the revenues flowing into the industry from its previous E&D investments, that is, cash flow, that are the key determinant of the magnitude of the industry's future** E&D investments. This question is complicated by the substantial changes in the industry's management and structure that have been wrought in the 1980s, and the as-yet unknown long-term effects that the new oil price environment will have on industry investment decision making.

In the short term—perhaps for **2** or **3** years—the level of cash flow from past investments and the effect it has on the industry's basic financial health seems likely to have a very strong effect on the level of new investment **even if prospects for profitable investments are basically good.** Many of the financial entities generally responsible for U.S. drilling and other production activities have been hurt badly because of the large cut in their revenues. Because these companies may hold land positions that could yield profitable drilling opportunities but no longer have adequate financial resources, new investment will suffer from a mismatch between opportunity and capability. Over the course of the next few years, however, loans will be renegotiated, companies will be restructured, and properties will be sold; many of the companies will go under, but those remaining should be stronger financially. Eventually, investment dollars will be made available to the industry **if there are attractive investment opportunities.** Thus, **the long-term outlook for oil supply is dependent on the basic profitability of the oil exploration and development prospects available to the industry.**

In OTA's view, it is by no means obvious that the potential profitability of the industry's available investment possibilities in exploration and development have sunk in lockstep with oil prices. Because the costs of oilfield services had escalated so sharply during the late 1970s and very early 1980s, there was considerable room for deflation in these costs when oil prices began to slide in 1981, and in fact these costs continued to deflate into 1986.[1] Only a careful examination of the balance of development costs and the oil revenues that will flow from incurring these costs will yield a true picture of the likely future of the industry in the face of continuing low oil prices. If the basic prospect economics are not as bad as they seem at first glance, there may be some real potential for industry activity levels—and reserve additions and production potential—to begin to rebound within a few years.

An evaluation of the potential profitability of domestic oil production prospects available to the U.S. oil industry would be invaluable in projecting the likely future levels of reserve replacement and production for the United States. For a variety of reasons, such an evaluation is not readily available. First, there is no reliable inventory of the available prospects, although a partial inventory (particularly of development prospects) could be assembled from drilling data and lease and field inventories in databases managed by groups such as Dwight's, NRG Associates, and others. A particular difficulty here is the substantial uncertainty associated with the size and characteristics of the remaining oil resource base. Second, much of the information necessary to do economic analysis, as well as extensive analyses of new prospects carried out by oil companies and their consultants, are proprietary. Third, were the necessary data available, the complexity of the evaluation would be very great, in part because of the large site-to-site variations among the

1 Although drilling costs rose briefly in 1985, according to the 1985 Joint Association Survey.

many thousands of prospects, and in part due to the complexity of the government taxes and regulations (e.g., the windfall profits tax) that strongly influence the profitability of the prospects.

To OTA's knowledge, there are no widely accepted, regularly updated evaluations of the potential profitability of new investments in oil E&D. There are, however, a number of sources of information and analysis that can provide some important insights about potential profitability:

- Industry comments: The oil companies conduct evaluations of profitability for their own properties and those properties they might wish to purchase, and most companies have recently undertaken extensive reevaluations in light of the new price environment.

  These evaluations are strictly proprietary, for obvious competitive reasons. However, a number of industry planners have been willing to discuss the **general results of these analyses with** OTA.
- **OTA economic analyses:** OTA has sponsored a limited series of economic analyses of potential oil exploration and development programs, in order to evaluate some of the claims of our industry contacts and to evaluate the impacts on profitability of alternative government policies, changes in expected oil prices, and improvements in efficiency.
- **Supply models using economic evaluation:** A few computer models of oil supply contain submodels that conduct economic evaluations, but these are very general in nature and appear unlikely to capture the full range of effects of the price drop. The Hydrocarbon Model used by the Gas Research institute contains an economic analysis package with one of the more detailed models of the oil and gas resource base, and the results of model runs can be useful in gauging changes in profitability; however, the model does not evaluate improved recovery of gas- and oil-in-place, an important factor in future reserve additions and production.
- **Analyses of one or a few types of investment:** A number of analysts have published results of individual profitability analyses for specific projects or areas. In addition, a few groups have conducted detailed economic analyses of some components of E&D activity. These include the Minerals Management Service's analyses of the U.S. Outer Continental Shelf resources and the National Petroleum Council's study of Enhanced Oil Recovery.[2]
- **Media statements:** Some industry executives have stated an oil price or price range that they claim is necessary to revive drilling or stabilize production, but these statements are essentially impossible to evaluate and they adopt different assumptions about costs, interest rates, future prices, and other critical variables . . . if they are indeed the result of actual analysis.

in addition, an examination of how drilling and other E&D costs may change over time will give further insight into how prospective profitability may change in the future.

Survey of Industry Analysts

Despite industry secrecy, some oil company analysts have offered to OTA some general information on the profitability prospects of new oil and gas E&D investment.

Essentially all of these analysts contend that the "inventory" of profitable oil and gas prospects has shrunk enormously at mid-1986 price levels of $12 to $15/bbl despite substantial declines in drilling costs and significant though lesser declines in other costs. One source estimates that only about 10 to 15 percent of the opportunities available at early 1980 prices remain available at $12 to $15/bbl. This figure is in line with the results of the IPAA/SIPES drilling survey, which shows an 80- to 85-percent drilling decline at $13,[3] and an API survey predicting an 83-percent decline (by 1991) at $10.[4] Although some companies claim that there are large numbers of economic prospects at these prices, most are said to be quite small and do not in the aggregate offer a major opportunity to replenish reserves. A

[2] National petroleum Council, *Enhanced Oil* Recovery, June 1984.

[3] Survey of their memberships conducted by the Independent petroleum Association of America and the Society of Independent Professional Earth Scientists.

[4] API Crude Oil Price Effects Survey, May 1986, compiled by Coopers and Lybrand for the American Petroleum Institute, results in API, *Two Energy Futures: National Choices Today for the 1990s, 1986* edition, July 1986.

very common theme is that the only arena that can support substantial drilling levels is relatively low risk, low-to-moderate cost development drilling, primarily for oil objectives (because gas markets are poor), with short lead times. This implies that most drilling will involve step-out (extension) and infill drilling, primarily at shallow depths, in areas with little risk of cost overruns or curtailments (for gas prospects). Other categories of prospects still viable at $12 to $15 include:

- continuation of projects where the majority of front-end capital has already been spent (enhanced oil recovery, offshore development drilling, and waterfloods that have passed the early development stages);
- projects that are necessary to maintain company positions, e.g., development and exploratory drilling needed to satisfy lease requirements, and joint ventures with substantial performance penalties; and
- projects with very distant production start-ups, if the company is confident of higher future oil prices. Although a few companies are continuing a portion of their long-term projects, more commonly these are being canceled despite company projections of "inevitable" long-term price increases.

A common and disturbing theme is that exploratory drilling is virtually dead at $12 to $15. A limited number of high-grade exploration prospects are said to remain economic, such as shallow pressured objectives,[5] and the shallow Gulf of Mexico. However, the bulk of high reserve potential prospects, both exploratory and development, are thought to be no longer economic. These include:

- Beaufort and Bering Seas, and most other frontier exploration;
- deep gas prospects;
- heavy oil offshore California (but some development projects with large sunk costs will continue);
- deepwater Gulf of Mexico;
- higher cost enhanced oil recovery, especially "grassroots" projects; and
- Overthrust Belt exploration.

[5]That is, shallow drilling objectives with reservoir pressures above the pressure caused by the weight of the rock, requiring lower-than-average pumping energy for production.

It has been reported in the trade press that there is little agreement in the industry about the crude price necessary to stimulate a drilling recovery, with some saying that $20/bbl would generate significant new activity and others that $35/bbl is necessary.[6] Most of our contacts were pessimistic that an increase to $18 to $20 oil prices would in any sense "rescue" the industry, although all admitted that significant additional prospects would become economic. These were said to include:

- some deepwater Gulf of Mexico exploratory prospects;
- considerable onshore wildcat drilling;
- additional enhanced oil recovery projects, especially select second-generation CO_2 projects with available CO_2 supplies, and some polymer projects;
- exploration and delineation drilling in the Beaufort Sea;
- limited offshore California development; and
- many waterflood projects, whose economic threshhold prices are-often between $15 and $20.

Although virtually all contacts would agree that there would be significantly more drilling activity at the $18 to $20 price, there was very substantial disagreement about the effect on reserve additions at that price. The more optimistic companies foresaw a considerable reduction in the rate of decline of reserves, for example, from a 9 to 12 percent/year decline at $12 to $15 to a 5 to 7 percent decline at $18 to $20. Other companies saw little improvement in reserve additions with a moderate price increase. Part of the disagreement may rest on the type of additional drilling activity foreseen at the higher price, with the pessimists possibly being skeptical that this price will elicit the high risk drilling they believe is necessary for the addition of important new reserves. All, however, agreed that a critical factor was price stability, which can be just as important as price level. Without stable prices, decisions on prospects will require either higher threshold rates of return or the functional equivalent, the need to satisfy profitability thresholds at prices substantially below the "expected" levels.

[6]"Fiscal 1985 Returns for OGJ400 Mixed," in *Oil and Gas Journal,* Sept. 8, 1986.

OTA Economic Analyses of Drilling Opportunities

OTA Prospect Analyses of Hypothetical Drilling Prospects.—OTA[7] has examined the potential profitability of some hypothetical onshore drilling prospects, focusing in particular on how profitability has changed over time, using a commercial economic analysis software package[8] and additional software developed by our contractor. The analysis evaluates both development and exploration prospects.

The development drilling prospects are 2,000, 4,000, 8,000, and 12,000 ft onshore wells with "per well" drilling and operating costs averaged across several geographic areas. The perspective is from the viewpoint of a driller who has a land position and must determine whether or not to drill.[9] The basic cost assumptions used in the analysis are summarized in table 7.

For each well, OTA calculated the profitability **expected** at the time of drilling—1972, 1981, 1985, and 1986–and, for the earlier years, the profitability **actually obtained.** The "expected" calculations used price scenarios generally reflective of price forecasts of the time (see table 8);[10] the "actual" calculations used historic prices for west Texas crude to 1985, and then adopted a price scenario assuming, in 1986 dollars, a $14/bbl price through 1990 and then a gradual increase to $20/bbl in 2000. For windfall profits tax calculations, OTA assumed that the wells were "Tier 3" wells, i.e. wells drilled on properties or into reservoirs that were not producing before 1980. Drilling and other costs were based on Energy Information Administration compilations of cost data for the relevant years. The key well parameters, initial production rate and reserves **per well, were selected by calculating the values needed to allow a 15 percent before tax real rate of return in 1986, assuming the $14/bbl price scenario.**

Table 9 shows the (before tax) rates of return for the four drilling dates and expected/actual price paths. Although the precise results apply only to the particular cases evaluated, the consistency of the results as well depth varies and

[7]Analysis by Thomas Garland, OTA contractor, Dallas, TX.

[8]The OGRE I I Oil and Gas Reserve Evaluation System analysis packdge developed by David P. Cook & Associates.

[9]For a longer term view of drilling economics, front-end bonuses must be added to total capital costs.

[10]OTA recognizes, however, that there has not been at any time a universal consensus about future prices, nor is it necessarily true that the price expectations actually used in oil company prospect analyses were similar to those made public. For example, although OTA used a level price, in constant dollars, for the 1972 expected case, some operators claim that they had expected to see increasing real prices at that time. For those operators, our calculated rates of return for the 1972 expected case are too low.

Table 7.-Assumed Costs To Drill, Equip, and Operate Development Wells, Selected Years

	Depth			
Year	2,000 feet	4,000 feet	8,000 feet	12,000 feet
Average equipment *cost per well (less* tubing *costs):*				
1972	21,690	29,074	39,121	30,143
1981	58,625	75,381	109,830	98,407
1985	54,278	70,413	98,396	82,154
1986	51,564	66,893	98,396	82,154
Average operating costs *per well/yr:*				
1972	3,541	4,456	5,701	6,803
1981	9,976	13,227	16,530	22,914
1985	11,512	14,810	18,840	27,142
1986	10,594	14,070	17,898	25,784
Average oil well drilling *costs:*				
1972	35,187	68,039	151,839	484,827
1981	144,598	296,037	705,519	2,113,390
1985	93,440	204,444	483,200	1,242,816
1986	74,752	227,555	386,560	994,253
Average dry *hole drilling costs:*				
1972	23,164	43,682	94,383	318,824
1981	114,753	236,737	541,811	1,622,440
1985	68,320	145,600	321,778	992,448
1986	54,656	116,480	257,422	793,958

SOURCE: Energy Information Administration data.

Table 8.—Oil Prices for West Texas Crude (current dollars per barrel)

	1972	1975	1980	1981	1982	1983	1984	1985	1986	1988	1990	1995	2000
1972 actual	3.48	7.64	21.84	35.06	31.77	29.35	28.87	26.80	14.00	15.14	16.38		
1972 expected (4.6)[a] .	3.48	3.98	4.99	5.22	5.46	5.71	5.97	6.24	6.53	7.15	7.82		
1981 "actual"				35.06	31.77	29.35	28.87	26.80	14.00	15.14	16.38	24.24	35.89
1981 expected (7) . . .				35.06	38.64	42.38	46.93	51.72	57.01	69.24	84.10	136.74	222.34[b]
1985 "actual"								26.80	14.00	15.14	16.38	24.24	35.89
1985 expected (4) . . .								26.80	27.04	27.40	28.07	38.54	53.00
1986 expected (4) . . .									14.00	15.14	16.38	24.24	35.89

[a][illegible] is the assumed inflation rate, percent.
[b]In 1981 dollars, $62/bbl.
NOTE: For "actual" cases, oil price is assumed to be $14/bbl (1986$) from 1986-90, gradually inflating to $20/bbl (1986$) by 2000. In other words, OTA deliberately assumes a "low oil price" scenario.
SOURCE: Office of Technology Assessment, 1987.

Table 9.—Economic Analysis of Drilling Prospects: Development Wells in Reservoirs Not Producing Before 1979 ("Tier 3" oil)

Depth (feet)		2,000	4,000	8,000	12,000
Initial production (bbl/day)		14	23	44	97
Reserves (bbl)		30,000	51,000	102,000	230,000
Year	**Scenario**	Real before tax rate of return (percent)			
1986	$14/bbl Oil	14.6	14.3	14.8	15.1
1985	Expected	52.0	44.0	41.5	35.2
	"Actual"	22.2	18.3	16.5	15.1
1981	Expected	42.9	38.2	32.2	22.6
	"Actual"	27.0	22.0	16.5	7.6
1972	Expected	Loss	Loss	Loss	Loss
	"Actual"	9.1	11.3	13.3	9.6

SOURCE' Office of Technology Assessment, 1987.

our examination of the regional variations in drilling costs lead us to believe that the general trends apparent in the results apply to a considerably broader set of oil development prospects.

The critical patterns apparent in the results presented in table 9 are as follows:

- At every depth, the expected profitability for 1986 is substantially lower than the expected values for both 1981 and 1985. Although drilling costs have declined substantially from previous years, many drilling prospects that appeared profitable in the early 1980s would not be drilled in 1986 **even if capital were available.** This tends to confirm, at least qualitatively, the claim made by most in the industry that a substantial part of the inventory of formerly economic prospects are now untenable.
- Because price expectations in both 1981 and 1985 were unrealistically high, the **actual** profitability of the drilling prospects would have been much lower than expected. In most cases, actual 1981 and 1985 profitability would have been similar to the expected 1986 profitability, which is based on quite modest price expectations.
- At every depth, prospects that would be considered profitable in 1986 would have been expected to be outright losses in 1972, before the initial price shock. This result is especially interesting because some analysts have likened 1986 conditions to 1972 conditions, concluding that U.S. production is likely to fall as quickly as it had been falling in 1972. Based on our results, these expectations may seem overly pessimistic. However, our analysis does not consider the availability of good drilling prospects. Most analysts would argue that, despite advances in technology and geologic knowledge since 1972, the availability of good physical prospects in 1972 was superior to that of 1986.
- Despite the substantial fall in prices between 1981 and 1985 and the reduced expectations for future price increases, the prospects looked somewhat more attractive in 1985. The improvement in profit expectations stems from the substantial decline in drilling costs between 1981 and 1985.
- Taking a longer term perspective, of an operator deciding whether to purchase and develop an unleased property, requires adding lease bonuses to the capital costs used in the analysis. This would tend to narrow the range of profitability between the different years, because bonuses typically are higher when profit expectations are higher, pulling down the profit from the prospects with the best potential. As discussed previously, the current slowdown in drilling activity gives the bargaining advantage to the operator, and lease bonuses for new property are likely to be low. Thus, the potential profitability of buying and developing a property in 1986 will be closer to the potential profitability of the same prospect in 1981 than the values shown in table 9.

Aside from the baseline analyses, we conducted a number of sensitivity runs to examine the effects of changing assumptions.

Table 10 shows the effect on profitability of drilling in an "old" reservoir rather than one

Table 10.—Economic Analysis of Drilling Prospects: Development Wells; Effect on Profitability of Windfall Profits Tax "Tiers"

Type of producer: independent
Wells: same physical parameters as in table 9.
Date of first production: 1981

	Real rate of return (before tax) (0/0)			
	"Actual" prices		Expected prices	
Depth (feet)	Tier 3	Tier 1	Tier 3	Tier 1
2,000	27.0	21.1	42.9	34.2
4,000	22.0	17.1	38.2	29.8
8,000	16.5	12.8	32.2	25.1
12,000	7.6	5.2	22.6	17.3

SOURCE: Off Ice of Technology Assessment, 1987

which was not producing prior to 1980. Because the tax rate is higher for old, "Tier 1" oil, and the "windfall profits" higher because of previous price controls on the oil, the profitability of the Tier 1 prospects would have been considerably lower than otherwise identical Tier 3 ("new oil") prospects. As shown in the table, both the actual and expected rates of return were substantially lower for the Tier 1 drilling prospects. In fact, for the deepest prospects, the expected profitability for 1981 is little different than the expected 1986 profitability. This effect would be exaggerated for major companies, because the windfall profits Tier 1 tax rate is 70 percent for majors and only 50 percent for independents (the results in the table are for independent drillers).

Table 11 illustrates the strong effect of expected oil prices on expected profitability. For every case, a price drop to $10/bbl transforms a modestly profitable prospect into a disaster, whereas a $20 price transforms the prospect into a handsome one. The strongly negative effect of the $10 price is particularly important because several of the exploration managers and planners interviewed by OTA claimed that drilling prospects were being subjected to a "low price hurdle, " i.e., being rejected unless they would remain profitable under the lowest price foreseeable . . . with the hurdle price often set at about $10. The effect illustrates the potential value of a government-legislated price "floor"; even if such a floor did not affect actual prices,[11] it might encourage

[11] Except, perhaps, by discouraging exporters from selling at below the floor, since the eventual landed price would be taxed up to the floor anyway.

Table 11.—Economic Analysis of Drilling Prospects: Effects of Oil Price on Rate of Return Tier 3 Development Wells, Drilled and Production Begun in 1986

	Real rate of return (before tax) (0/0)			
Oil price ($/bbl)	2,000 ft	4,000 ft	8,000 ft	12,000 ft
20	41.3	37.2	34.3	33.0
14	14.6	14.3	14.8	15.1
10	Loss	Loss	1.3	3.49

SOURCE: Off Ice of Technology Assessment. 1987

drilling by raising the hurdle price required for drilling prospects, presuming that the companies trusted the government not to remove the floor if world prices fell well below it. Also, of course, the strongly positive effect on profitability of the $20 price implies that a mechanism to raise oil prices could have significant positive effects on drilling. The ultimate value of such a mechanism cannot be judged, of course, without a reliable analysis of how much drilling—and how much additional reserves and production capacity—would be created by each additional dollar in the oil price.

The price sensitivity calculations were made assuming drilling costs would not change within the price range examined. This is likely for the $10 case because current costs are so low that there is little room for downward movement. If $20 oil generates substantial new drilling activity, however, drilling prices might rise somewhat, reducing profitability.

Table 12 illustrates the effect on profitability of changing drilling costs, for a single 4,000 ft development well. As discussed in the section on costs, drilling costs have gone through a classic boom and bust cycle during the last decade or so, and some analysts fear that a substantial rebound in costs could occur if drilling activity begins to pick up. Conversely, substantial improvements in drilling technology have occurred over the same time period, although the effects on costs of the improvements were submerged by the imbalance between demand for and availability of drilling services. Continuing technology improvements could keep costs down if the industry accepts fully the challenge of finding and producing oil in a low price environment.

The results show that the movement in drilling costs from the 1985 average ''per well' costs to

Table 12.—Economic Analysis of Drilling Prospects: Effect of Changing Drilling Costs on Rate of Return

4,000 ft. development well, Tier 3
Initial production = 23 bbl/day
Reserves = 50,000 bbl
Drilled, production begins in 1986
$14/bbl oil price

Drilling cost	Rate of return (o/o) Before taxes	After taxes
1985 average	8.1	7.8
10°/0 below 1985	10.8	10.1
20°/0 below 1985	14,3	12.8
30°/0 below 1985	18.5	15.8

SOURCE: Office of Technology Assessment, 1987.

30 percent below the average–which has occurred in some areas—approximately doubles the rate of return, a substantial effect.

Finally, table 13 illustrates the effect on profitability of changing Federal and State tax policies to ease tax burdens on the industry, as has been called for by numerous industry spokespersons. As shown clearly by the results, a moderate easing of taxes—adding investment tax credits, raising depletion allowances, and cutting State severance and ad valorem taxes—does improve the 1986 expected profitability of these wells, but only modestly.

In addition to the analyses of development prospects, OTA examined the comparative profitability over time of a series of exploration and development programs that find and develop small oilfields (each field requires five producing wells for full development) in known producing provinces. The wildcat wells in the program are successful in one out of six attempts; development wells are assumed to be 80 percent successful. Well costs, expected oil prices, and other economic variables are assumed to be the same as in the previous analysis, except that geophysical and other costs associated with exploration wells are assumed to add 20 percent to the total costs of these wells.

Table 14 displays the rates of return (real, before taxes) associated with the exploration and development efforts at 2,000, 4,000, 8,000, and 12,000 ft, with and without lease acquisition costs included.[12] A constant (real) $20 oil case is included to show the effects of an import tariff set at this level. I n contrast to the earlier effort, only "expected" rates of return—associated with typical oil price expectations of the time—are shown for the 1972, 1981, and 1985 cases. The table also shows the per well initial production rate and reserves necessary to obtain a 15 percent before-tax real rate of return for 1986.

The rates of return results are very similar to the previous analysis for development well drilling: at every depth, prospects that would be considered profitable (15 percent before-tax real rate of return) in 1986 would have been expected to be outright losses in 1972 and, in contrast, considerably **more** attractive in 1981 and 1986, whether or not lease acquisition costs are in-

[12] Values for lease acquisition costs were obtained from the Congressional Research Service analysis described below, see table 17.

Table 13.—Economic Analysis of Drilling Prospects: Policy Options for Improving the Profitability of Development Drilling

Same physical parameters as in table 9
Date of drilling and first production: 1986
Expected price = $14/bbl
Type of producer: small independent

	Real after tax rate of return (o/o) 2,000 feet	4,000 feet	8,000 feet	12,000 feet
1. 1986 tax system	13.27	12.75	12.73	12.78
2. Change investment tax credits				
a. to 200/0	14.16	13.44	13.30	13.19
b. to O (new law)	12.08	11.83	12.05	12.33
3. Allow 80°/0 depletion limit.	13.38	12.80	12.74	12.78
4. Cut severance and ad valorem taxes from 100/0 to 50/0	15.56	14.71	14.39	14.33
5. Allow higher depletion allowance:				
200/0 of gross.	14.00	13.53	13.50	13.50
300/0 of gross.	14.35	14.15	14.26	14.25

SOURCE: Office of Technology Assessment, 1987.

Table 14.—Economic Analysis of Exploration and Development Projects

Well depth, feet	2,000	4,000	8,000	12,000
Initial production rate, bbl/day/well	20	35	71	172
Reserves, bbl/well	41,000	72,000	146,000	377,000
Initial year	Expected rates of return, real before tax, percent			
A. Without ***lease acquisition costs:***				
1986 $20/bbl oil	38	34	33	30
1986 $14/bbl oil	15	14	15	15
1985	45	39	38	33
1981	35	31	27	21
1972	Loss	Loss	Loss	Loss
B. With ***lease acquisition costs:***				
1986 $14/bbl oil	9	8	9	9
1985	30	25	25	21
1981	21	18	16	12
1972	Loss	Loss	Loss	Loss

SOURCE Office of Technology Assessment, 1987

eluded. Also as in the previous analysis, expectations of a constant $20 oil price from 1986 on will boost expected profits to the same general range as the 1981 and 1985 prospects. This result lends some credibility that an import tariff set to produce a minimum $20 domestic price might do some good, at least for this sort of “small target” drilling and assuming that drillers (and their investors) trust the Federal Government to maintain the tariff even if world oil prices were to plunge.

Comparing the initial production rates and reserves needed to produce a 15 percent return between this exploration case and the earlier development drilling case demonstrates that exploration requires better prospects than development to achieve the same return. Although this only confirms the obvious—the exploration program must pay off the high cost of multiple dry holes (and buying the lease), whereas for incremental development drilling this cost is “sunk”-it serves to bolster the industry’s contentions that exploration drilling will absorb substantially greater cuts than will development drilling.

The “dry hole risk” is crucial to the economics of exploratory drilling. Although technological optimists have often predicted large reductions in this risk, and in certain situations this has been accomplished, improved technology has been essentially unsuccessful in boosting the **industrywide risk in any measurable way, Table 15** shows how such a boost might effect the economics of exploration programs, by examining how the rate of return would shift if the wildcat success rate shifts from one new field discovery in six attempts to two or three discoveries in six attempts. As shown in the table, an improvement to a 50 percent success rate would double the rate of return for the type of exploration program examined in this analysis. Unfortunately, most oil producers would view such an improvement as a more appropriate topic of science fiction than of scientific analysis. Nonetheless, the results illustrate the value of pursuing improvements in the efficacy and cost of seismic and other exploration techniques.

Prospect Analyses Conducted for OTA by the Congressional Research Service. -Jane Gravelle, Specialist in Industry Analysis and Finance, and Bernard Gelb, Analyst in Industry Economics, both of the Economics Division of the Congressional Research Service, have conducted a ser-

Table 15.—What Happens If Dry Hole Risk Is Reduced? ($14/bbl oil, no lease acquisition costs)

	Well depth, feet			
	2,000	4,000	8,000	12,000
Success rate	Expected rates of return, real before tax			
1:6	15	14	15	15
2:6	20	19	20	20
3:6	29	29	30	33

SOURCE Office of Technology Assessment, 1987 ies of economic analyses for this study.[13] The analyses are of a series of combined exploration/development programs hunting for relatively small fields in four producing regions: the Permian Basin, Powder River Basin, Anadarko Basin, and the Gulf Coast Basin of Offshore Louisiana. The exploration/development programs are described in tables 16 and 17. As in the OTA analysis described above, the same physical prospects are evaluated for four different years: 1972, 1981, 1985, and 1986. The oil prices used in the analyses generally conform to the price expectations of the times (table 18), except for 1986, which uses three hypothetical price scenarios. Only the "expected" profitabilities are examined, since decisions to drill are made on the basis of such expectations.

The prospect evaluation employs a discounted cash flow analysis, with revenues and costs discounted to the present, to arrive at estimates of "net present value''—the amount that the net after-tax revenues (gross revenues less operating costs, royalties, and all taxes), discounted to the present, exceeds the initial investment. In the baseline runs, the lease acquisition costs were not included, primarily because these costs are so variable from project to project. The real discount rate was set at 10 percent, so that when the net present value is zero, the project earns a real (i.e., corrected for inflation) 10 percent rate of return. Table 19 presents the tax and financial variables used in the analyses.

The results of the baseline series of prospect analyses are presented in table 20, with the results displayed in the form of the net present value expressed as a percent of the initial investment. If a real 10 percent rate of return is considered the minimum "hurdle rate" of a prospect–the minimum expected profitability that would convince the operator to proceed with the program —then the 1972 Powder River Basin project, with zero net present value, could have proceeded if the operator did not have to pay a lease bonus (unlikely) or if he had paid the bonus already and, perhaps on the basis of new information, reevaluated the property to arrive at the expected result displayed in the table. Prospects with positive net present values allow the operator some leeway to pay bonuses, with the amount determined primarily by the competition for properties and the land's potential for some alternative use that might be hindered by a drilling program.

The results are generally similar to those of the OTA analysis of development and exploration

[13]B.A. Gelb and J.G. Gravelle, "Oil Prospect Profitability in the United States: Estimated Expectations in 1972, 1981, 1985, and 1986, " CRS Report No, 87-38E (revised), Mar. 24, 1987.

Table 16.—Characteristics of Hypothesized Prospects

	Producing region and type of operator				
Variable	Permian Basin Independent	Powder River Basin Major	Powder River Basin Independent	Anadarko Basin Independent	Offshore Louisiana Major
Number of wells:					
Dry	10	10	10	10	6
Successful	10	10	10	10	13
Well ***depth (feet):***					
Dry	8,500	6,400	6,400	3,300	8,800
Successful	8,900	6,100	6,100	3,300	8,900
Initial year production:					
(thousands of barrels).	222	169	169	48	1,450
Annual physical depletion:					
(percent)	10	10	10	10	10

NOTE: The Permian Basin is mainly in Texas; the Powder River Basin, in Wyoming; and the Anadarko Basin, in Kansas. Except for well depths, the data shown refer to each individual prospect as a whole.

SOURCES AND METHODS OF ESTIMATION: Number of holes (wells) —Based on Congressional Research Service (CRS) geologist's field experience and industry rules of thumb regarding: a) ratios of dry holes to successful wells holes; and b) the typical number of producing holes for a reasonably profitable prospect. The ratio of successful holes to dry holes for the offshore prospect is higher than onshore because the much higher cost of drilling offshore forces operators to be more cautious in drilling "wildcat" wells. Well depth—Typical well depths of the respective producing regions in 1972, based on data from the Joint Association of Drilling Costs, published by the American Petroleum Institute. Offshore wells are assumed to be drilled in 100 feet of water, and production platforms to have 12 "slots," Initial year production-Derived by CRS from the relationships among total industry production, outlays (for exploration, development, and production), and reserves for a "normal" year. Based on data from the Annual Survey of Oil and Gas, compiled and published by the U.S. Bureau of the Census. Annual physical depletion—Based on actual ratio of total U S crude oil production in a year to proved reserves.

Table 17.—Estimated Investment and Operating Costs (thousands of dollars)

		Producing region			
		Permian Basin	Powder River	Anadarko	Offshore Louisiana
Geological and geophysical	1972	12% of sum of drilling plus lease and well equipment			
	1981				
	1985				
	1986				
Land acquisition and leasing[a]	1972	25°)0 of sum of drilling plus lease and well equipment			14,400
	1981	33°/0 of sum of drilling plus lease and well equipment			16,416
	1985	25°/0 of sum of drilling plus lease and well equipment			3,000
	1986	20°/0 of sum of drilling plus lease and well equipment			1,500
Drilling	1972	2,424	1,775	436	9,680
	1981	11,956	6,753	1,851	50,929
	1985	10,140	5,165	1,436	28,571
	1986	7,600	3,850	1,080	21,150
Lease and well equipment	1972	293	325	153	2,170
	1981	1,155	872	575	6,200
	1985	1,145	935	520	6,200
	1986	1,090	890	495	5,830
Annual operating costs	1972	50	49	27	742
	1981	142	142	82	2,417
	1985	165	152	93	2,360
	1986	164	151	92	2,300

aNot includedin the estimation of expected profitability

SOURCES AND METHODS OF ESTIMATION Geological and Geophysical average ratio— derived from data in the Annual Survey of Oil and Gas, compiled and published by the U S Bureau of the Census Land Acquisition and Leasing—Onshore: Ratios for 1972 and 1981 derived from data in the Annual Survey of 011 and Gas, ratios for 1985 and 1966 estimated by authors, based on price expectation scenarios. Offshore: Derived from average lease bonuses paid per acre in Federal offshore lease sales Drilling —Assumed number of wells Onshore—10 dry, 10 pay; offshore—6 dry, 13 pay. Drilling costs estimated from Joint Association of Surveys on Drilling Costs published by the American Petroleum Institute, for 1972, 1981, and 1984, from the 1985 Survey of Combined Fixed Rate Overhead Charges for Oil Producers, published by Ernst and Whinney, and from comments by an oil industry association economist Lease and Well Equipment—Estimated for 1972 1981, and 1985 from data in Costs and Indexes for Oilfield Equipment and Production Operations in the United States, published by the Energy Information Administration, estimated for 1986 based on comments by Energy Information Administration industry expert. Annual Operation Costa-Same as for lease and well equipment

Table 18.—Assumed Crude Oil Prices

Producing region	1972	1981	1985	1986
	Price per barrel in initial year (initial year dollars)			
Permian Basin	$3.35	$35.90	$26.00	$14.00
Powder River Basin	3.30	35.90	28.00	14.00
Anadarko Basin	3.25	35.90	25.50	14.00
Offshore Louisiana	3.55	36.00	27.25	14.00
	Anticipated annual change as of initial year (constant dollars)			
All producing regions	No change	A) +2°/0 indefinitely B) See note	1985-90: –3.00/0 After 1990: +2.5°/0	A) 1985-90: + 8% After 1990: +2°/0 B) 1985-90: O°/o After 1990: 3.5°/0 C) 1985-90: O°/o After 1990: 0°/0

NOTE: Anticipated annual changes for 1981 price scenario "6'' -1981 to 1985: – 0.80/0; 1985 to 1990 + 8 20/0, 1990 to 1995: +6.5°/0, 1995 to 2000 + 2 3°0, 2000 to 2020 + 0.9%. Initial year price for 1981 price scenario "B'" asumed to be $34 per barrel for all producing regions

SOURCES Initial year prices based directly and/or indirectly on data from the Energy Information Administration, U.S. Department of Energy, Petroleum *Supply Annual, Monthly Energy Review,* and *Annual Energy Review* Anticipated changes based directly and/or indirectly on Projections by the Energy Information Administration and by several private organizations, including oil companies, energy industry groups, and other organizations

Table 19.—Tax and Financial Variables

	1972	1981	1985	1986[a] Old	1986[a] New
Interest rate	8.20/o	16.0%	12.7%	10.2%	
Inflation rate	4.60/o	9.6%	4.0%	4.0%	
Debt share	17.0%	17.0%	17.0%	17.0%	
Federal Income Tax Treatment					
Rate	48.0%	46.0%	46.0%	46.0%	34.0%
Intangible drilling costs	Expensed	Expensed	Expensed*	Expensed*	Expensed+
Losses	Expensed	Expensed	Expensed	Expensed	Expensed
Equipment					
Investment credit rate	10.0%	10.0%	10.0%	10.0%	0
Tax Life (years)	9.2	4.5	4.5	4.5	7
Depreciation method[b]	SYD	150 DB	150 DB	150 DB	DDB
Reduction in basis	No	No	1/2	1/2	No
Depletable costs[c]	Percentage depletion	cost depletion	cost depletion	cost depletion	cost depletion
State Tax Treatment					
Severance Tax					
Louisiana	.078**	.125	.125	.125	
Texas	.046	.046	.046	.046	
Wyoming***	.03	.04	.015-.06	.015-.06	
Kansas	0	0	.08	.08	
Income Tax					
Louisiana	,04	.08	.08	.08	
Texas	0	0	0	0	
Wyoming	0	0	0	0	
Kansas	.0675	.0675	.0675	.0675	

[a]Old refers to Federal tax law in effect in 1986. New refersto the Tax Reform Act of 1986, which became effective in ?987.
[b]SYD—Sum of years digits; 150 DB—150 percent declining balance; DDB—Double declining balance
[c]22% percentage depletion for 1972.
+Thirty percent of costs of majors amortized over five years.
*Twenty percent of costs of majors amortized over three years.
"The Louisiana severance tax wasa per unit tax of26 cents per barrel in 1972. The rate equivalent in the table would decline overtime.
***The Wyoming severance tax rises to 6 percent after 1989, but is currently 15 percent
NOTE: Because of data limitations, it was not possible to incorporate local property taxes. Application of the windfall profits tax depends on price levels,

SOURCES: inflation and interest rates are basedon lagged values following Patrick Hendershott and Sheng-Cheng Hu, "Investment in Producer's Equipment;'How Taxes *Affect Economic Behavior,* Herrry Aaron and Joseph A. Pechman (eds.), Brookings institution, Washington, DC, 1981, p. 85-128, Debt ratios are from Don Fullerton and Roger Gordon, "Afle-examination of Tax Distortions in General Equilibrium Models,'' *Behavioral Simulation Methods in Tax Policy Analysis*, Martin Feldstein (ed.), National Bureau of Economic Research, Universityof Chicago Press, 1983, p 372.

Table 20.—Estimated Anticipated Profitability of U.S. Oil Prospects 1972,1981,1985, and 1986 (net present value as a percent of initial investment)

Initial year and price scenario	Permian Basin, Independent	Powder River Basin, Major	Powder River Basin, Independent	Anadarko Basin, Independent	Offshore Louisiana, Major	Unweighted average
1972	7	0	0	– 4	16	4
1981A	74	113	113	86	97	97
1981 B	74	114	114	84	97	97
1985	60	119	120	72	142	103
Old Tax Law:						
1986 A	21	49	50	13	66	
1986 B	14	39	40	6	51	28
1986 C	1	24	24	– 7	29	
New ***Tax Law:***						
1986A	25	59	60	14	79	
1986B	17	46	48	6	60	33
1986 C	1	28	29	–10	34	

NOTE Real discount rate assumed to be 10 percent,

SOURCE: Congressional Research Service, 1987 wells, but the regional detail provided by the CRS analysis yields some interesting insights. The expected profitability of the hypothetical prospects in mid-1986 was lower than the expected profitability in 1981 or 1985, but generally higher than in 1972—precisely as in the OTA analysis. Even if future oil prices are assumed to rise quite rapidly (8 percent per year in real dollars, as in price scenario 1986A), and despite a sharp drop in drilling costs between 1985 and 1986, expected profitability in 1986 is appreciably lower than in 1985 for all five prospects. However, in the Permian and Anadarko Basins, under the 1986B prices (identical to those used in the OTA analysis), the expected profitability for 1986 is only modestly better than it was in 1972, If the $14 oil price is assumed to hold, except for rising with the cost of living, the 1986 prospects are slightly inferior to the 1972 prospects in these basins.

The Permian and Anadarko Basins correspond to regions JS and JN in table 24 (in the next section), which displays the relative development prospects computed by GRI's Hydrocarbon Model. That model calculated the prospects for both these regions to be quite good. These results are not necessarily contradictory, because the Hydrocarbon model runs incorporated relatively optimistic assumptions about oil prices.

In addition to the cases discussed above, CRS examined the effects on prospect profitability of the Tax Reform Act of 1986 (which will take effect starting in 1987). A most surprising result is that the new tax rules show a small but significant **improvement in profitability over the current tax law in every prospect, for every price scenario. Apparently,** the lower tax rates in the new law override the effects of losing the investment tax credit. This conclusion would likely not hold for a company that had excess tax credits or an actual net loss under the current law (because the lower tax rates under the new law would be irrelevant), nor does it account for any adverse effects of the alternative minimum tax in the new code. It will hold, however, for situations where the decision to pursue the prospect is at the margin where the company is deciding whether to pursue one more prospect, and the company does not have excess tax credits or a net loss for the year. In OTA's view, this is the decision most worth examining, since it is the one faced by most companies trying to decide whether to increase their rate of drilling . . . and thus it is the decision that, made in the aggregate, will determine whether a drilling rebound is likely to occur.

CRS also examined the effects of a $10/bbl and $20/bbl expected (real) price, an assumed repeal of all State severance taxes, a 20 percent refundable tax credit for drilling costs (costs which are currently in the nature of intangible drilling costs, and which exclude depreciable equipment and depletable geological and geophysical costs), and a 27.5 percent oil depletion allowance.[14] The results are displayed in table 21.

The results for the $10 and $20 oil price and the cut in severance taxes are pretty much the same as those arrived at in the OTA analysis. The $10 price–which is particularly significant since conservative industry analysts may use this price as a "hurdle" price for profitability—creates a disastrous drop in profitability. The $20 price, which simulates a variable import tariff set at this value, boosts profitability substantially. (However, it drilling costs were to increase as a result of revived activity, the boost in profitability would be partially offset.) The cut in severance taxes has only a modest beneficial effect in most regions (the Louisiana offshore prospect is an exception), and does not appear capable **by itself** of making a substantial difference in industry activity.

An interesting exercise is to compare the results of the $20 price case to the 1981 and 1985 results, because drilling in these two years was at a high level (even though the 1985 rig count was somewhat depressed). The net present values at $20 oil were back to 1981-85 levels for all regions but the Anadarko, implying that an import tariff set at this level might spur a significant drilling rebound **if the oil companies trusted the Federal Government to leave the tariff in place AND if sufficient capital were made available to the independent producers.** Of course, confidence in such a result would require an examination of a far wider set of cases than was accomplished here. Also, we stress that this result does **not** imply that a return to a free market price of

[14] All of the cases incorporate the new tax rules.

Table 21 .—Estimated Anticipated Profitability of U.S. Oil Prospects, Under Specified Price and Policy Alternatives (net present value as a percent of initial investment)

	Producing region and type of operator					
	Permian Basin,	Powder River Basin,		Anadarko Basin,	Offshore Louisiana,	Unweighted
Price or policy alternative	Independent	Major	Independent	Independent	Major	average
$10/bbl constant price[a]	–14	6	7	–25	6	–4
Variable import tax setting price at $20/bbl[a]	53	102	103	44	120	84
20°/0 drilling cost credit[b]						
1986A	41	73	74	26	93	
1986 B	32	61	62	18	74	47
1986 C	17	42	43	2	48	
No State severance taxes						
1986A	30	65	66	24	106	
1986B	21	52	54	15	85	42
1986C	5	29	31	–3	54	
27.5°/0 depletion allowance						
1986A	39	76	77	29	105	
1986 B	29	64	65	20	84	49
1986 C	11	44	45	1	53	
27.5°/0 depletion allowance, with old tax law						
1986A	40	76	77	33	103	
1986 B	31	64	65	25	84	51
1986 C	15	44	45	8	55	

[a]Prices are per barrel of crude oil Estimation procedure for import tax assumes that the price of domestic oil would equal that Of imported oil.
[b]Under this option, Federal income tax liability for a tax year would be reduced by an amount equal to 20 percent of expenditures for drilling in that year
[c]Under this option, Federal income tax liability for a tax year would be reduced by an amount equal to 27.5% of gross income from the property.

NOTE Except where Indicated, the estimates have been made using the provisions of the new tax law,

SOURCE: Congressional Research Service, 1987,

$20 might also accomplish a drilling rebound. It is the **expectations of future prices as much as the current price that drives industry activity, and the current volatility of prices will tend to undermine industry confidence.**

The 20 percent drilling credit, an idea not explored in the OTA prospect analysis, does produce a moderate improvement in profitability in all cases, and could prove interesting to policymakers who favor using the tax code to boost E&D activity.

The 27.5 percent depletion allowance also provides a moderate improvement in profitability in all cases. in general, it boosts profitability slightly more than the 20 percent drilling credit.

Inclusion of lease acquisition costs in the analyses will tend to make the 1985 and 1986 results look more favorable in comparison to the 1981 results, because 1981 was the height of the drilling boom and lease acquisition costs were especially inflated. As evident from table 17, these costs have come down considerably in recent years, especially in the offshore.

Table 22 presents the net present values for the same cases as in table 20, as well as for the $20 oil case, with the lease acquisition costs incorporated in the analysis. Inclusion of these costs changes none of the basic conclusions obtained from examining table 20, but the results do demonstrate more decisively than the original analysis that 1985 was actually a very attractive time to drill, that reduced oil revenues were often more than compensated for by reduced costs.

Analyses by the Gas Research Institute (G RI)

GRI operates an energy supply and demand forecasting system called the Hydrocarbon Model that incorporates a detailed description of the United States Lower 48 oil and gas resource base, on a field-by-field basis, and an economic analysis model that assesses the expected profitability of exploratory and development drilling based on the characteristics of the resource opportunities. GRI's Strategic Analysis and Energy Forecasting Division has recently conducted a spe-

Table 22.—Estimated Anticipated Profitability of U.S. Oil Prospects 1972, 1981, 1985, and 1986 With Lease Costs Included (net present value as a percent of initial cost, including lease acquisition costs)

	Producing region and type of operation				
Initial year price scenario	Permian Basin, Independent	Powder River Basin, Major	Powder River Basin, Independent	Andarko Basin, Independent	Offshore Louisiana, Major
1972	–12	–18	–18	–21	–46
1981A	34	64	64	43	58
1981 B	34	65	65	42	58
1985	31	80	80	41	125
1986A	3	27	28	–4	58
1986 B	–3	18	19	–l o	43
1986 C	–14	5	5	–21	26
$20 Constant Price	30	72	73	22	109

SOURCE Office of Technology Assessment based on Congressional Research Service analysis, 1987

cial run of the Hydrocarbon Model aimed at evaluating the effects on oil and gas production of low oil prices.[15]

The primary assumptions used for the analysis were:

- oil price (1986$) of $11.76/bbl in 1986, rising to $14.41 in 1990 and $21.60 in 2000; gas prices of $1.47/mmBtu, $l.60, and $2.95, respectively;
- 1986 drilling costs 10 percent below 1985 levels; and
- producers accept a minimum real rate of return, after tax, of 7 percent.

Some characteristics of the model and the assumptions used will tend to drive the estimates of oil and gas production both above and below a "most likely" level. For example, factors that would tend to overestimate supply include:

- The minimum rate of return, 7 percent, appears low. This rate is lower than the rate used by GRI in its baseline (higher price) runs. Most industry analysts expect that the perceived instability of oil prices will raise the minimum rate of return acceptable to the industry.
- The drilling model does not consider the availability of capital as a constraint, implicitly assuming that capital will be made available to the industry if there are acceptable drilling prospects to pursue. For at least the short term, a lack of capital is an important constraint on industry activity, especially among independent producers.

Factors that would tend to underestimate supply include:

- The model does not include the effects on supply of enhanced oil recovery and other activities to improve the recovery of oil- or gas-in-place.
- Actual 1986 drilling costs may be as much as 30 percent below 1985 level's, and not the 10 percent assumed in the model run (however, many operators do not expect costs to remain this low for long).

The results of the model run, displayed in table 23, show oil production declining at a 5 percent/yr rate through 1990, then 3.1 percent/yr rate through 1995, and a 1 percent/yr rate through 2000. Gas production holds constant through 1990 and then declines at about 1.2 percent per year through 2000. Development drilling is projected to dip considerably and remain at levels substantially lower than those of the early

Table 23.—Lower-48 Oil and Gas Production (excluding increased recovery from old fields)

Year	Oil[a] (million bpd)	Gas (tcf)[b]
1985	6.63	16.1
1990	5.13	16.1
1995	4.36	15.1
2000	4.16	14.3

[a]Does riot include lease condensate
[b]Trillion cubic feet

SOURCE T J Woods and P D Holtberg, "Hydrocarbon Activity in an Era of Low Oil Prices," 61st Annual Technical Conference and Exhibition of the Society of Petroleum Engineers, New Orleans, Louisiana, Oct. 5-8, 1986 SPE Paper 15355 Congressional Research Service, 1986.

[15]T. J. Woods and P.D. Holtberg, "Hydrocarbon Activity in an Era of Low Oil Prices," 61st Annual Technical Conference and Exhibition of the Society of Petroleum Engineers, New Orleans, LA, Oct. 5-8, 1986, SPE Paper 15355.

1980s—e.g., 32,500 total development wells in 1990 versus the rate of 50,000 to 70,000 wells per year sustained during the first half of the 1980s, (Part of this dip may be attributed to the model's exclusion of drilling designed to increase recovery efficiency in known fields.) On the other hand, exploratory drilling is projected to dip initially and then recover sharply, to nearly 14,000 wells/yr in 1990 and 23,000 wells/yr in 1995 versus 13,000 to 17,000 wells/yr during the early 1980s. This latter result is surprising because of the greater costs generally associated with exploratory drilling and the widely held industry opinion that most future drilling will focus on field development and away from exploration.

The model shows Lower 48 crude oil (not including lease condensates) production declining by 1.5 mmbd by 1990 and 2.3 mmbd by 2000 (from 1985 production). As shown in chapter 3, of the forecasts prepared in 1985, with expectations of stable oil prices in the low-to-mid $20s for the remainder of the 1980s, the most pessimistic—the EIA Energy outlook—projected a 0.9 mmbd reduction in **total United States crude plus condensate production[16] by 1990, with only 0.7 mmbd attributable** to Lower 48 production. The Chase "Consensus" forecast projected only a 0.6 mmbd drop for the United States as a whole. The EIA projection for 1995 is for a 2.4 mmbd drop in total United States production, with 1.9 mmbd attributable to Lower 48 production, whereas the Chase projection for the total United States is for a 2 mmbd drop. Thus, on the surface, the GRI results imply a substantial decline in future oil production attributable solely to the projected difference in prices between the moderate 1985 expectations and a lower price scenario based on an extension of 1986 price levels. However, the authors of the GRI papers describing this analysis do not themselves interpret these results so pessimistically, because they believe that greater recovery of oil-in-place—not incorporated in the model—will compensate for much of the projected reduction in "standard" oil production. They attribute the current drilling decline primarily to the immediate effects of the large drop in the oil industry's cash flow and conclude that the overall resource economics of drilling have not been greatly affected by the price drop.

[16]Presumably, lease condensate production will decline when natural gas production declines, so that the projected total decrease in crude plus condensate production implies a lesser decrease in crude alone.

Aside from the overall production projections, the GRI model exercise yields interesting insights into other potential changes associated with the 1986 price drop. In particular, the exercise yields insights into the viability of new drilling activity, and the profits likely to be gained from earlier activity, in different portions of the country. For example, the model results indicate that the extensive drilling in the early 1980s to all depths in southern Louisiana, to 5 to 15,000 feet in the Texas gulf coast, and to 10 to 15,000 feet in the Permian Basin are yielding poor economic returns, and new drilling in these area/depth combinations should drop sharply with continuing expectations for unacceptable rates of return or even outright losses. On the other hand, prospects for new drilling in many region/depth combinations remain surprisingly good despite the lower prices, including offshore California, especially in shallow water (less than 600 ft), onshore California to O to 10,000 ft, the Rocky Mountains and Northern Great Plains to all depths above 15,000 ft, and several other regions. Table 24 shows the economic prospects for drilling in the Hydrocarbon Model regions based on the low price exercise.

MMS Analysis of the Effect of Lower Oil Prices on OCS Recoverable Resources

A reduction in oil exploration activity on the Outer Continental Shelf (OCS) and the statements of industry planners imply that many OCS exploration prospects that were economic in the early 1980s at oil prices in the $25 to $35 price range are not economic at $15 or $18. This in turn indicates that the total recoverable oil resource was diminished by the recent oil price decline.

The Minerals Management Service (MMS) of the Department of the Interior has evaluated the effect of varying oil price on the magnitude of the undiscovered "leasable resources" in the Outer Continental Shelf (leasable resources are resources that would be profitable to explore for and develop). Table 25 presents MMS's estimate

Table 24.—Economic Prospects for Drilling, Based on GRI Hydrocarbon Model Runs

	Region	Prospects
A	(Ohio, Kentucky, Tennessee, Georgia further east and offshore)	excellent* at 0-10,000 ft (established depths), good to poor at greater depth
B	(Mississippi, Alabama, Florida)	good to excellent shallow and deep, poor at 5,000-10,000 ft (most common drilling interval)
c	(Minnesota, Wisconsin, Michigan, Iowa, Illinois, Indiana, Missouri)	marginal
D	(Arkansas, North Louisiana, Central Texas)	good at 0-10,000 ft (most common drilling interval), marginal to poor below
E	(South Louisiana)	poor at 0-15,000 ft, marginal at greater depth
G	(Texas Gulf Coast, South Texas)	good to excellent at 0-5,000 ft (high past active drilling), marginal 5,000-15,000 ft (most common drilling interval), poor at greater depths
HI	(Dakotas, Nebraska, Montana, Wyoming, Idaho, Colorado, Utah, Arizona, New Mexico)	good to excellent at 0-15,000 ft, marginal at greater depth
JN	(Mid-Cent-KanSaS, Oklahoma, Texas, RRD #lo)	good at 0-5,000 ft, and greater than 10,000, good to excellent at 5,000-10,000 ft
JS	(Permian Basin, Southeast New Mexico, Texas RRD 7C,8,8A)	good at 0-10,000 ft, greater than 15,000 ft, marginal 10,000-15,000 ft
L	(California, Nevada, Pacific North West)	excellent at 0-10,000 ft (most common drilling intervals), poor to marginal at greater depths
EGO	(West Gulf, offshore Louisiana and Texas, shallow offshore Alabama, Mississippi deep Norphlet)	good at all water depths except uncertain in Norphlet trend
LO	(Offshore California and Pacific North West)	excellent at 0-600 ft. water depths (most common drilling interval), good beyond 600 ft

* Definition of Terms Poor = below 5 percent real after tax rate of return; Marginal = 5-10; Good = 10-15; Excellent = above 15

SOURCE Off Ice Technology Assessment, based on GRI data

of leasable resources in 22 planning areas for United States Gulf of Mexico oil prices of $17, $23, $28, and $34/bbl[17] in January 1987.

The analysis indicates that a 50 percent drop in price yielded a 34 percent decrease in leasable resources overall, but that, in some basins (Beaufort Sea, St. Georges Basin, Chukchi Sea, and others), 100 percent of the resource was rendered uneconomic. Presumably, some of the basins were lost because the level of recoverable resources dropped below levels necessary to support the costs of required transportation systems or other minimum fixed costs.

A reliable evaluation of the effect of the OCS resource "loss" on U.S. oil production requires a detailed examination of the individual basins and the various governmental and industry plans for developing these basins. However, it appears likely to us that in most cases the effects on production of the loss at the $17 price will be small within this century, because of the long time lag–generally a decade or so–between OCS initial leasing and initial production, and because generally the higher cost resources would not be foremost on most development schedules anyway. Of course, this conclusion will not hold when the total loss in leasable resources becomes larger . . . as will certainly happen at prices substantially below $17.

OTA does not believe that the MMS analyses are necessarily relevant to projecting the incentives for exploratory drilling aimed at very large, long-term frontier prospects. Many or most major companies will pursue such prospects regardless of current prices because they cannot project prices for the time frame of actual development of any potential discoveries (in most cases, beyond 10 years) and they cannot pass up the chance of discovering a field that is so large it can be profitably developed at almost any conceivable oil price.

[17] With an assumed 1 percent annual real price growth.

Table 25.—Sensitivity of Leasable Resource Amounts to Current Oil Price

1987 U.S. Oil Price/bbl Gulf of Mexico	Leasable resources, million barrels of oil equivalent			
	$17	$23	$28	$34
Planning area:				
Western Gulf of Mexico	3,790	4,490	4,630	4,630
Central Gulf of Mexico	3,930	4,070	4,110	4,110
Southern California	540	730	880	880
Navarin Basin	0	180	720	790
Middle Atlantic	90	110	230	230
South Atlantic	250	410	680	770
St. George Basin	0	0	260	260
Eastern Gulf of Mexico	180	330	420	470
Chukchi Sea	0	0	0	400
Beaufort Sea	0	0	250	310
Northern California	150	280	410	410
North Atlantic	10	30	30	70
Central California	110	180	220	220
Washington/Oregon	50	50	60	60
Gulf of Alaska	0	0	0	30
North Aleutian Basin	0	0	0	20
Norton Basin	0	0	0	20
Kodiak	0	0	0	0
Florida Straits	0	10	10	10
Hope Basin	0	0	0	0
Shumagin	0	0	0	0
Cook Inlet	0	0	0	0
Total	9,100	10,870	12,910	13,690
Percent of $34 resource	660/0	79 "/0	94%	100%

SOURCE: U.S. Department of the Interior, Minerals Management Service, 5-Year Outer Continental Shelf Oil and Gas Leasing Program for January 1987-December 1991, app. F, draft

costs

The cost components relevant to a particular decision about exploration, development, or continued production depend on the precise circumstance of that decision:

- In deciding whether to continue production from an **existing well in good operating order, only the net production costs–called the "lifting costs"—are considered. The cost of acquiring the lease, finding the oil, drilling the production well, and building the necessary infrastructure such as pipelines** are important to the company's profit and loss sheet, but these costs are "sunk" and should not enter the specific production decision; production will continue as long as the net revenues from the well's production exceed the lifting costs. For wells needing significant repairs, the amortized cost of these repairs must be added to lifting costs, and the sum balanced against revenues.
- Decisions to expand production by drilling **new wells in known fields** need to consider the expected lifting costs plus the cost of drilling the well, including a risk factor to account for the possibility that the well could be dry. If the well is drilled outside the known boundaries of a reservoir, i.e., a new pool test or an extension test, the risk component could be quite substantial.
- Adding production from a **new** (as-yet-undiscovered) **field requires considering the costs of acquiring the lease, drilling a number of exploratory wells to discover the field, drilling development wells, and, at times, adding significant infrastructure.**

Finally, many decisions must be made at stages intermediate to these cases . . . for example, the decision whether to drill exploratory wells after the lease is acquired. Such intermediate decisions are forced on producers when economic conditions change suddenly, disrupting the previous calculations that led to the initial phases of oilfield activity.

In other words, at any instant, the oil industry has a large "inventory" of potential investment opportunities ranging from unleased, unexplored land with potential oil reserves that are only a gleam in a geologist's eye, to older fields with a few remaining undrilled sections, or with some potential for infill drilling (drilling at a closer spacing than was initially planned) or other production-enhancing investments. For the older fields, most or all of the leasing, exploration, and infrastructure costs have already been incurred. Thus, it is inherently cheaper to pursue a prospect in the most developed areas, and becomes progressively more expensive—in terms of incurring expenses for lease bonuses, seismic exploration, laying pipelines, etc.—to pursue prospects at earlier and earlier stages of the production cycle. The only reasons why undeveloped prospects are pursued at all are because the inventory of prospects in known and partially developed fields is limited and must be replenished, and because the company believes it will find more profitable oil or gas wells–with more reserves, higher production rates, higher quality oil, with less water cut and lower operating expenses–than in the more developed areas.

Lifting Costs.—As noted above, decisions to continue production from existing wells are dependent on lifting costs remaining below the revenues flowing to the producer, that is, total revenues less royalties and taxes[18] must exceed costs. Thus, when oil prices are $15/bbl, royalties are one-sixth, and taxes are 5 percent, lifting costs must be less than $ (15 - 15/6) * .95, or $11.88/bbl for the well to remain profitable to operate.

According to the "standard reference" for lifting costs—the Joint Association Survey[19]-average lifting costs for oil and gas in the United States have been well below "per barrel" oil prices, even with taxes and royalties factored in. Average U.S. lifting costs were between 60 and 70 cents per barrel between 1959 and 1970, and did not rise above $2 per barrel until 1980. The 1982 **Annual Survey of Oil and Gas** shows 1982 lifting costs (without taxes) for oil and gas to be about $3.40 per barrel of oil equivalent (BOE), with average costs for Alaska at $0.97/BOE,[20] the Lower 48 onshore at $4.03/BOE, and the offshore at $2.81/BOE. Lifting costs for oil alone should be a bit higher because operating costs are generally higher for oil wells than for gas wells. The averages conceal a wide range, especially for the Lower 48; for onshore production, wells with high water production or in high cost secondary and tertiary recovery operations may have lifting costs exceeding $15/bbl, whereas certain high output wells may produce oil at less than $1/bbl.

Estimates of U.S. lifting costs at values considerably higher than the values reported in the Joint Association Survey have been reported in the media and elsewhere. The reasons for the discrepancies are not clear, although they may include definitional problems (the estimates may include excise taxes, although these are unlikely to add much more than $1.00/bbl to the total, or may refer only to higher cost wells without specifying that this is so). Some examples of higher reported lifting costs are:

- "Average United States lifting costs, including taxes" reported to be just above $10/bbl for the oil and gas system as a whole, in testimony of Dr. Alan Greenspan, President, Townsend-Greenspan & Co., Inc.
- The lifting cost of bringing oil to the surface is reported as varying from $7 to $15/bbl at onshore wells by R. Stanfield in National *Journal, 3/29/86.*
- Operating costs (including royalties and severance taxes) for different U.S. regions are presented as: Texas, $4 to $8/bbl except strippers, Gulf of Mexico $8 to $10/bbl, Arctic North Slope $14 to 24/bbl, in N. Barakat and S.M. Chronowitz, "Crude Oil: Nearing and Equilibrium, " Smith Barney Financial Services, Futures Special Report, Vol. 8 No. 5, spring 1986.
- Average lifting costs in sample lower 48 fields estimated as $6.80/bbl, in J. L. Copeland, Presentation to the Keystone Energy Futures Project on United States Liquid Fuel Policy, July 14, 1986, Copeland, Wickersham, Wiley & Co., Inc.

In general, OTA is skeptical of estimates of lifting costs well above those of the Joint Association Survey. However, the Copeland, Wickersham, Wiley, & Co. estimates were derived from a field-by-field survey of production costs and cannot be dismissed so lightly.

To what extent might lifting costs decline further in response to low oil prices?

Operating costs for specific categories of wells have begun to trend slightly downward during the past few years as a result of reductions in energy costs and some reductions in the costs of services and equipment for well maintenance. In particular, costs for fuel have declined in parallel with oil prices; this is an important cost component for enhanced oil recovery projects, but generally is less important for ordinary production because pumping energy often is electric and electricity costs have not fallen significantly. In general, the very substantial cost reductions seen in drilling services have not been matched by similar reductions in operating costs, nor are they likely to be. The drilling cost reductions have been driven primarily by the very large decreases in demand for these services; for example, the

[18] Some analysts choose to ignore taxes and royalties because these are viewed as negotiable; they believe these will be reduced sharply by their collectors if the alternative is a massive shutdown of drilling and production. For example, see the writings of M. Adelman and A. Tussing. Thus far, there is little indication that major reductions in royalties and taxes are taking place.

[19] Joint Association Survey, American Petroleum Institute.

[20] Lifting costs for Alaska are low because the high transportation costs to bring this oil to market have precluded the development of resources with high lifting costs.

number of operating rigs has declined from over 4,000 in 1981 to about 700 in 1986. The number of wells, on the other hand, will not decline drastically, and may even increase, so maintenance services will not have to face the enormous idle capacity faced by the drilling service industry. However, many well operators will defer maintenance, lessening the overall demand for these services, and certain categories of services—e.g., workovers for offshore wells—will face competition from equipment formerly devoted to drilling new wells. Other costs–e.g., electricity costs—may face downward pressure from State governments concerned about the potential for well closings. For example, the Oklahoma Corporation Commission has asked Oklahoma electric utilities to lower rates for well operations. Therefore, operating costs seem likely to remain stable or perhaps decline slightly in the near future, assuming oil prices stay low.

In addition to some moderate reductions in technical operating costs, there is some potential for reductions in royalties and taxes. In general, most royalty reductions are likely to be concentrated on new operations where operators can take advantage of the dropoff in competition for new properties to pressure property owners for concessions. There is less potential for royalty reductions with properties that have already been leased. For them, the property owners may be particularly reluctant to accept a lower royalty rate because their royalties have already been slashed because of the lower oil prices. Also, further development of producing properties will often remain quite attractive even at low oil prices because the major capital expenditures have already been made, so there will be less economic pressure on the owners of such properties to grant royalty concessions. However, on the most marginal properties, those most likely to be shut in, some property owners may be faced with the choice of accepting a lower royalty rate or losing their royalties entirely as the production shuts down.

The potential for lower tax rates is uncertain. The primary oil-producing States face a considerable dilemma in assessing tax strategy for oil production. A major portion of their operating revenues are derived from taxes on oil production, and the substantial dropoff in collections associated with the price drop has caused considerable budgetary problems. Reductions in tax rates probably would save some wells from shutting down. Given the low average lifting costs for oil wells, however, it seems likely that any reduction would lead to a further significant drop in State revenues, because the revenues "saved" because of the few wells prevented from shutting in would be overwhelmed by revenue losses associated with wells that would have continued to produce without a tax break. However, each shut-in well costs the State jobs, reduced taxes associated with employment, and costs associated with added needs for social services.

From the above, OTA concludes that pressures for reductions in lifting costs from existing wells are likely to continue to drive down average U.S. lifting costs, although only to a moderate extent. In addition, new drilling in a low price environment may tend to avoid areas and geologic situations known to yield high operating costs, even though operating costs are not the primary factor considered in drilling decisions; this would tend to hold down the average lifting costs of new wells. Finally, the wells being shut in and thus removed from the U.S. inventory of producing wells are those with the highest costs. Thus, OTA expects the U.S. average lifting cost to decline in the coming years if oil prices remain low, although most of this decline will result from a shift in the distribution of physical characteristics in the U.S. inventory of wells rather than from a substantial lowering of costs for particular services and types of wells.

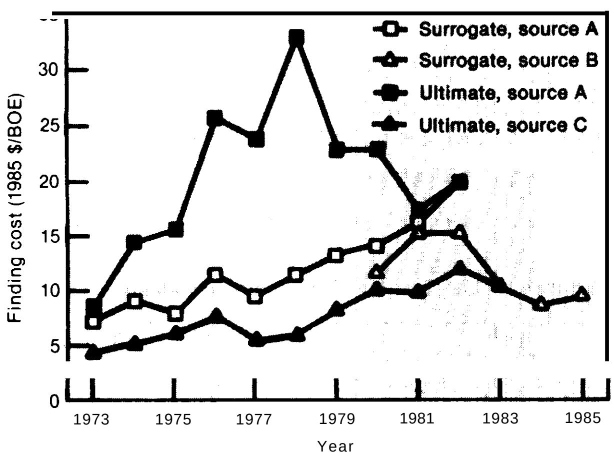
"Finding" Costs.– Finding costs are the full range of costs—including the cost of lease acquisition, seismic surveying, exploratory drilling, reservoir modeling, and development drilling—needed to bring oil and gas reserves to the point where they can be produced.

As explained above, decisions to drill new wells or otherwise develop new production depend on expected finding costs, or on components of these costs, depending on the stage of development the proposed activity is in. For example, the decision to buy a lease and drill new field wildcats should consider every component of finding costs as well as expected lifting costs if oil and gas are discovered. The decision to drill a development well should consider only the components of finding cost beginning with the cost of planning that particular well, since all previous costs have been sunk and cannot be retrieved.

Finding costs have undergone a major cycling, through boom and bust, during the past decade. For example, figure 6 illustrates the changes in finding costs over the past decade and a half, first during the drilling surge that followed the 1972 embargo and then during the decline accompanying the oil price declines that began in 1981. The major factors affecting these costs include:

- **The hyperinflation associated with the rapid increases in demand for drilling services, land, and other factors of production.** The inflation was caused by a growing inefficiency in providing drilling services and the greater "economic rent" collected by providers of these services . . . and the turnaround in costs was caused by the overall drop in oilfield activity. Similarly, the costs of the other "factors of production" —including land and seismic analysis—rose with the drilling boom and have deflated with the slide in drilling activity.
- **Changes in drilling targets,** with operators expanding their drilling efforts towards marginal targets and targets in difficult-and high cost—environments during the period of rising oil prices (driving finding costs up), then adjusting during the price slide by withdrawing from higher cost targets and focusing primarily on targets in less difficult environments with lower finding costs. Some of the movement towards marginal targets, however, reflected not economics but resource depletion, that is, a declining **availability** of low-cost opportunities.
- **Technological improvements** in drilling, seismic surveying, and other components of exploration and development.

Figure 6.—Oil and Gas "Finding Costs"
(costs for exploration and development)



NOTES
1 "Surrogate finding costs" match reserves booked in a year to expenditures made in that same year, even though actual costs to find and develop reserves are spread out over a number of years "Ultimate finding costs" attempt to match exploration and development costs to reserves by assuming typical lag times and levels of field growth.

2 The conversion to 1985 dollars was based on the GNP price deflator

SOURCES
A—L T Byrd, (The Keplinger Companies) and D.L. Moore (Arther Anderson & Co),"U S Oil and Gas Finding and Development Costs, 1973-1982, Lower 48 Onshore and Off shore," Sept 18, 1984 For lower 48 States.

B—Arther Andersen & Co., *Oil and Gas Reserve Disclosures, 1980-1983* and *Oil arrd Gas Reserve Disc/osures,* 1981-1985. For entire United States

C—A T Guernsey, *Profitability Study, Crude Oil and Natural Gas Exploration, Development and Production Activities in the USA 7959-1983,* report to Shell 011 Co , June 1985 For lower 48 States

There currently is no consensus on how finding costs will vary in the future. Although many analysts expected finding costs to continue a downward trend, established in late 1982, into 1985, the 1985 finding costs appear to have trended upwards.[21] In all probability, a substantial part of any future changes will be the result of changes in drilling patterns, as these patterns continue to adjust to the new economic conditions caused by the lower oil prices. Effects of technological change are difficult to predict because lower research budgets would tend to slow change whereas the radically new price environment might act to spur it on.

There also is no consensus on how the basic costs of services and other factors of production will behave in the future, although changes in these costs were a primary driver of past changes in finding costs. Right now, certain of these costs—especially drilling costs—are so low that the providers of the services are barely surviving,

[21] According to the Arthur Andersen & Co. *Oil and Gas* **Reserve** *Disclosures, 1981-1985, 1985* finding costs per barrel were $11.85 (without revisions) and $9.39 (with revisions) compared to $9.94 and $8.29 in 1984.

deferring equipment maintenance and actually losing money in many operations.[22] For these services, any tightening of supply will surely lead to price increases, but the extent of such increases and their timing is not readily predictable (certainly, the overhanging surplus of equipment will limit cost increases in the near term). For factors that need not involve risk or investment on the provider's part—such as lease acquisition—it seems more likely that costs can remain extremely low until there is a substantial recovery of drilling activity.

Capital Availability and the Permanence of Capital Flight

Many industry analysts point to a shortage of capital to finance investments in exploration and development as a major factor in the severe depression that is rocking the upstream sectors of the oil industry, especially the independent producers. The severity and duration of this capital shortage would appear to be a critical determinant of future U.S. oil reserve additions and production.

During the late 1970s and early 1980s massive amounts of capital flowed into the oil industry as oil prices and corporate revenues soared amid expectations of even higher world oil prices. Between 1978 and 1985 over $300 billion was invested in petroleum exploration and development (see table 26). Annual expenditures peaked at $57.7 billion in 1981 and then declined to $33 billion in 1985. In the wake of the 1985-86 price drop, industry spending on E&D dropped sharply to half the 1985 level.[23] As can be seen from table 26, much of the increased E&P spending up to the early 1980s came from the independent sector.

The original wave of investment in exploration was funded from several sources: from rapidly expanding internal cash flows generated by higher oil prices; from private investors seeking high returns on publicly traded stocks and bonds or tax sheltered investments in oil and gas drilling funds, partnerships and trusts; from conventional bank loans secured by equipment or reserves; and from private placements by banks, other financial institutions, and large investors. Table 27 shows the sources of funds for the Chase Manhattan Group of large oil companies. Similar aggregate information is not available for independents.

Since the 1981 peak in the exploration boom, several trends have combined to limit internal and external capital availability for new exploration:

[22] For example, certain types of drilling services can now be obtained at less than the cash cost of providing these services. The providers are willing to accept the loss because the cost of mothballing their rigs is greater than the net cost to them of drilling.

[23] *Oil and Gas Journal*, Feb. 23, 1987.

Table 26.—U.S. Exploration and Development Outlays for 1973 to 1985 (billions of dollars)

	Larger firms[a]			Independents[b]			Total	
Year	$ Billions	'/0 Change	'/0 Total	$ Billions	% Change	% Total	$ Billions	% Change
1973	5.3	25	65	2.9	27	35	8.1	26
1974	8.6	62	69	3.8	33	31	12.4	52
1975	6.4	–25	62	3.4	–10	33	10.3	–17
1976	8.6	36	60	5.7	66	39	14.5	42
1977	10.3	19	62	6.2	9	38	16.5	14
1978	11.3	9	58	8.0	30	42	19.3	17
1979	15.0	33	56	11.8	46	44	26.8	39
1980	20.6	37	57	15.6	33	43	36.2	35
1981	29.8	45	53	26.7	71	47	56.5	56
1982	30.0	1	54	25.4	–5	46	55.4	–2
1983	22.7	–25	55	18.2	–28	45	40.9	–26
1984	22.1	–3	53	19.4	6	47	41.5	1
1985	NA	NA	NA	NA	NA	NA	33.0	–20

Exploration and Development Outlays include both capital expenditures and and exploration expenses exclu that portion associated with proven propert acquisition.
[a] "Larger firms" includes most of the major oil companies in the Chase Manhattan Bank Group plus several other large domestic independents. Figures are drawn from the annual publication by the Chase Manhattan Bank, "Financial Analysis of a Group of Petroleum Companies" and adjusted for the additional companies.
[b] "Independents" includes all other oil and gas exploration and production companies. Figures are derived by subtracting expenditures by larger firms frOm total industry expenditures.
NA = not available.

SOURCE: Independent Petroleum Association of America, "United States Petroleum Statistics—19Bf3° (final).

Table 27.—Sources and Uses of Working Capital of a Group of Petroleum Companies (million dollars)

	Funds available from					Funds used for							
Year	Cash earnings	Long term debt issued	Stock[a] issued	Other[b]	Total	Capital expenditures	Dividends	Long term debt repaid	Other[c]	Total	Internal funds	External funds	Total funds
1975	22,714	10,129	a	1,217	*34,060*	*24,205*	4,819	5,316	1,740	*36,080*	23,931	10,129	34,060
1976	25,828	10,310	a	2,426	*38,564*	*26,036*	5,208	5,230	829	*37,303*	28,254	10,310	38,564
1977	29,003	8,678	a	4,424	*42,105*	*27,156*	5,995	5,954	1,508	*40,613*	33,427	8,678	42,105
1978	33,184	4,930	a	5,226	*43,340*	*28,770*	6,781	6,885	1,562	*43,998*	38,410	4,930	43,340
1979	55,844	8,568	a	6,984	*71,396*	*42,229*	8,127	8,249	2,473	*61,078*	62,828	8,568	71,396
1980	66,859	11,900	a	5,862	*82,821*	*53,776*	10,305	9,728	2,613	*76,422*	70,721	11,900	82,621
1981	63,207	16,585	a	1,723	*81,515*	*63,976*	11,068	10,020	4,867	*89,931*	64,930	16,585	81,515
1982	60,884	14,980	450	6,283	*82,597*	*64,538*	11,265	9,281	3,731	*90,019*	67,167	15,430	82,597
1983	60,256	8,704	300	6,706	*75,669*	*49,521*	11,057	7,524	4,507	*72,609*	66,962	8,707	75,669
1984	53,549	22,168	179	–4,738	*71,158*	*43,182*	10,297	8,280	21,671	*83,430*	48,811	22,347	71,158
1985 (est.)	63,600	19,100	500	14.200	*97,400*	*47.900*	12,600	22.600	19,500	*102.600*	77.800	19.600	97.400

[a]Included i. Long Term Debt Issued.
[b]Other includes sales of assets and other transactions
[c]Other includes investments and advancements and preferred and common stock retired
a Included in Long Term Debt Issued

SOURCE. The Chase Manhattan Bank, Financial Analysis of a Group of Petroleum Companies

- The windfall profits tax cut sharply into the majors' earnings from oil production at prices over $20/bbl, removing an additional source of funds that might have been available for exploration and production (E&P) spending and perhaps deterring additional investments. (Countering the effects of the WPT, however, were tax incentives such as the investment tax credit.)
- Lower wellhead oil and gas prices meant lower revenues and earnings for many of the independent producers, who carried a lower WPT burden, and thus reduced internal cash flows that could be available for exploration.
- Federal income tax law changes in 1982 diminished the attractiveness of oil and gas tax shelters for private investors at the same time as the overall rate of return on oil industry investments began to decline in relation to the rate for manufacturing industries.
- The price-related decline in the value of oil and gas reserves and drilling equipment also reduced the value of assets that could be used as CO l lateral for bank loans.[24]
- The high debt levels incurred by many independents to fund the boom in exploration in 1979 to 1981 began to take an increasing share of available cash flow as prices fell and cut into discretionary capital spending.
- Similarly, the increased debt levels incurred by restructuring strategies (see section on "The Restructuring of the U.S. Oil Industry") absorbed a significant share of cash flow.
- A number of regional banks in the Southwest which had heavily financed E&P spending came u rider pressure from the simultaneous poor performance of loans to the oil and gas drilling services and equipment sectors and the agriculture and real estate sectors. With a rise in problem loans, many of these banks were less willing to lend their available funds for risky drilling ventures.

[24]Banks were commonly using a rule of thumb that required posting of collateral that had at least twice the value of the secured loans under several price scenarios. Oil prices have fallen as much as 60 percent in 1986. Moreover, some analysts believe that proven 011 reserves have declined in average price from $9 to $5 per barrel as of late 1986 and the value of loans that they could be used to secure has gone down correspondingly.

Even as the amount of capital available was constrained by these trends, disappointing exploration results and a decline in both oil and natural gas prices deterred investments of available funds in many high risk plays by oil companies and private investors. Exploration no longer enjoyed a privileged status among the major integrated oil companies and larger independents, as management weighed various options for enhancing shareholder values, and some opted instead to use available internal and external funds to pursue acquisitions, share buy backs, and other investments.

The sharp drop in oil production revenues and earnings that followed the 1985-86 price drop drastically increased the entire industry's capital availability problems by dramatically reducing the cash flow available to fund exploration and capital investment. The decline in capital availability has affected sectors of the industry differently, however, with the drilling and service companies and the smaller independent producers suffering the most. The high debt loads incurred by these companies, which funded much of the boom, placed them at greater risk during the initial price decline and the 50 percent fall in drilling activity between 1981 and 1985. By 1985, many of these firms were under financial stress, some were forced into default and were liquidated, and some sought protection under the bankruptcy laws. Of the remaining operators, many saw their financial condition weakened as a higher share of their cash flows went to debt service and the value of assets that could be used as collateral plunged. This reduction in collateral values also caused some loans to go into technical default, even though operators remain able to meet scheduled payments. As noted above, the regional banks which had financed their efforts were also u rider pressure from poor performance in the agriculture and real estate sectors, and were less likely to lend their available funds for risky drilling ventures. Although there are no reliable sources of information on private financing, which is a major source of funds for independent operators, many industry analysts believe that availability of private funds has declined because of current conditions in the industry and uncertainties over the implementation of the 1986 tax law. With fewer willing investors, companies may have to offer better terms to acquire funds, and combined with uncertain oil prices, this provides a strong incentive to avoid the high risk exploration ventures that often represent the best opportunities for reserve replacement.

Also hard hit were larger companies that were highly leveraged due to corporate acquisitions or anti-takeover strategies. These firms cut E&P spending first in 1985, with only a modest decline in world oil prices. They took even larger cuts in 1986 as cash flow was diverted to meet or reduce debt obligations and to maintain key financial indicators. These companies have less flexibility in the use of their available cash, and their ability to borrow further may be impaired by the high level of existing debt and uncertainty over future revenues. Perhaps because of this concern, several of these highly leveraged companies have devoted substantial efforts to reduce their high debt levels and/or to refinance the debt at more attractive interest rates.

In general, however, the larger companies—and especially those companies that did not incur sizable debt loads during the boom years—do not appear to have suffered nearly as much from capital availability problems. In particular, the integrated companies' downstream earnings helped to cushion some of their upstream losses as refinery margins increased and demand for gasoline and residual fuel oil increased. For example, as table 27 shows, total funds available from internal and external sources declined by only about $11 billion in 1982 to 1984, while capital spending (excluding acquisitions) dropped over $20 billion. Rather than a capital shortage, there appears to have been a deliberate shift away from E&P spending towards other uses of capital, such as acquisitions and debt repayment. Statements in company annual reports and congressional testimony generally attribute the reduced capital spending to a lack of profitable opportunities and not a lack of funds from internal or external sources. Also, the 1985 annual and 1986 quarterly reports of many major integrated oil companies and larger independents continue to show new long-term debt, indicating that their access to financing has not been substantially impaired. In 1985 to 1986, the **use of** borrowed funds changed; with limited exceptions, these funds have been largely used to refinance existing obligations, to repurchase shares, and to acquire assets of other companies rather than to fund new oil and gas development.

Even with the most recent drop in revenues, large oil companies remain among the largest cash flow generators in the United States and the world. Table 28 shows changes in revenues and earnings for selected major U.S. oil companies for the first 9 months of 1986. Not all of the earnings losses in the exploration and production segments this year will translate into lower cash availability, as many companies took one-time paper writeoffs against earnings.

Even the problems of the independent sector must be evaluated carefully. According to **Energy Performance Review,** independent oil and gas producers and oil field service companies suffered sharp declines in revenues and earnings in 1986; a group of 126 independent producers posted losses of $1.8 billion for the first 9 months of 1986. However, more than 100 percent of year to date losses were attributable to noncash charges against income.[25] The size of the noncash charges indicates that many companies likely posted net gains on their continuing operations that were then reduced by noncash charges against earnings to reflect such things as writedowns in the values of reserves because of lower prices, and losses on the sale of operations.

The critical question for determining the future of industry investments in exploration and development is: To what extent is the current pattern of the domestic oil and gas industry a transitional phase, and to what extent is it essentially stable so long as prices do not rise?

Many industry observers believe that uncertainty over oil prices and the factors noted above virtually ensure that, in the short run, little outside capital will flow into oil exploration and development. In the longer run, however, the relative importance of these factors is less clear. Other industries have been able in the past to adjust

[25] "Rough Third Quarter for Energy Companies," *Energy Daily*, Dec. 8, 1986, p. 1,

Table 28.—Financial Performance of Selected Oil Companies, First 9 Months 1986 v. First 9 Months 1985

	Revenues		Net profits			Capital and exploration expenditures				
Company	Million $	85-86 % Change	1986 Million $	85-86 % Change	1985 Million $	1986 Million $	1985 Million $	% Change 85-86	% of net income 1986	% of net income 1985
* Exxon	57,470	−16	3,880	27	3,065	5,627	7,144	−21	145	233
• Mobil	37,233	−16	1,204	96	615	2,179	2,436	−11	181	396
• Chevron	21,685	−37	801	−15	946	2,019	2,914	31	252	308
• Texaco	24,800	−29	675	−27	926	1,601	2,005	−20	237	217
• Shell	12,841	−14	628	−37	998	2,131	2,636	−19	339	264
• Amoco	15,394	−28	582	−63	1,563	2,114	3,372	−37	363	216
• ARCO	11,368	−33	551	—	—	—	—	—	—	—
Conoco	7,495	−21	331	−27	—	—	—	—	—	—
• Sun	8,230	−23	315	179	—	—	—	—	—	—
• Phillips	7,642	−36	217	−33	—	—	—	—	—	—
Ashland	7,300	−11	209	42	147	281	290	−3	135	198
* Occidental	1,175	4	161	−75	643	687	749	−8	427	116
• Unocal	6,297	−28	127	−73	460	666	1,100	−40	526	239
Texas Oil & Gas	732	−39	38	−87	—	—	—	—	—	—
Louisiana Land & Exp	620	−29	25	−67	—	—	—	—	—	—
Murphy	1,048	−37	13	−79	—	—	—	—	—	—
Coastal	48	−9		−95	94	125	219	−43	2655	233
Marathon	6,100	−23	(1)	—	—	—	—	—	—	—
Pennzoil	1,414	−17	(1)	—	—	—	—	—	—	—
American Petrofina	1,493	−15	(30)	—	—	—	—	—	—	—
• Tenneco	10,930	−2	(42)	—	—	—	—	—	—	—
• Diamond Shamrock	1,951	−21	(73)	—	—	—	—	—	—	—
Amerada Hess	3,139	−45	(278)	—	105	184	427	−57	—	405
Kerr– McGee	1,946	−20	(301)	—	109	230	325	−298	—	298
* Standard	7,750	−24	(376)	—	1,079	1,380	2,115	−35	—	196
Total	270,805	−22	8,660	−28	10,751	19,224	25,731	−25	263	239
• OTA group total	224,766	−23	8,649	—	10,295	18,404	24,471	—	213	238

*OTA Group

SOURCE : Oil and Gas Journal

to economic shocks by writing off bad investments, selling capital stock to new investors who can make a profit because they are buying at bargain prices, restructuring to reduce costs, rethinking their investment strategies, and developing new technologies that can better deal with a changed business environment. For larger integrated companies and independents without sizable debt loads, bank loans and private financing appear to remain available. Even though these funds have been largely used to refinance existing obligations, to repurchase shares, and to acquire assets of other companies rather than to fund new exploration ventures, it is by no means certain that this spending pattern will continue.

It may be overly pessimistic to assume that the oil industry's level of investment in exploration and development will not improve without a rise in oils prices that will restore some of the profitability of prior investments and boost cash flows. In the long run, the level of investment in E&D may be determined primarily by the basic economics of exploration and development, as defined by the question: How much return on investment can be gained by an additional dollar of investment? If new investments in oil exploration and development appear profitable, companies may once again plow back more of their funds into those ventures, and either new sources of capital could appear or else the old sources could return.

However, a critical and highly uncertain issue, for which there are no readily apparent answers, is the amount of time it might take for investment capital to return. Given the rapidity of projected production declines, an uncertainty of a year or more in a recovery from the industry's capital flight translates into a substantial uncertainty in the amount of any actual production decline. Furthermore, it is probable that any initial injection of capital into the industry will tend to gravitate to the lowest-risk opportunities. For a time, these opportunities may be the purchase of reserves and producing properties.[26] Only after the inventory of available properties shrinks is capital likely to flow primarily to the exploration and development activities needed to revitalize the industry.

Premature Loss of Existing Production: Stripper Wells

There is widespread concern that low oil prices will force many of the Nation's "stripper" oil wells, wells averaging 10 barrels or less per day, to shut down, with many or most never to reopen, their reserves lost. This concern is magnified by the importance of stripper wells to the U.S. oil supply, Approximately 1.3 mmbd–14 percent of total domestic oil production—are produced by stripper wells. There are over 400,000 of these wells in operation, producing an average 2.8 barrels daily .17 U.S. oil reserves associated with stripper wells total about 4.5 billion barrels,[28] 16 percent of current U.S. reserves of 28.4 billion barrels .29

A large shutdown, were it to occur, would affect a few States disproportionately. Between them, Texas and Oklahoma have a bit over half the Nation's stripper well production. Adding stripper production from California and Kansas incorporates fully three-fourths of the Nation's stripper production .30

The concern about shutdowns stems from the wells' physical characteristics as well as from the State and Federal regulations that govern them. Many of the wells have high per barrel operating costs because their maintenance costs are spread over so few barrels of production and also because, in many areas, the well production includes a high proportion of water that must be pumped to the surface, separated from the oil, and properly disposed of. At low oil prices, revenues from oil sales may drop below operating costs for many wells. For other wells with small positive cash flows during ordinary operation, the onset of any extraordinary repair costs may signal an impending well closure. And even without closure, many operators are likely to delay needed repairs and thus forfeit the additional production rates these repairs would allow.

If the oil production from shut-in stripper wells could be restarted, there would be no impact on national security. in many cases, however, production shutdowns will be permanent. For example, for "water-drive" wells—wells where formation water pressure moves oil to the well bore —a prolonged production shutdown may ruin the well, i.e., renewed pumping would produce only water. For all stripper wells, the time period during which a well's production can be shut in is limited by State and Federal regulations to prevent contamination of groundwater aquifers penetrated by the wells. Prior to the current price drops, most State and Federal regulations limited shut-ins to 90 days, with requirements that the well either be returned to production or be permanently plugged (with a concrete seal) after that time. With current well-plugging techniques, reentering a well is said to be little different in cost from drilling a new well. For wells with particularly low production rates, it seems unlikely that production would ever be restarted, and plugging these wells would likely result in a permanent loss of the reserves associated with the wells. Because of the concerns about a widespread loss of both production and reserves, some States have lengthened their shut-in grace period to a year or more.[31]

There is little disagreement with the thesis that oil prices at levels near or below $15 per barrel will have a significant adverse effect on stripper well closure rates and U.S. oil production rates. Unfortunately, however, a general lack of data on stripper wells makes it quite difficult to estimate quantitatively just what the effect will be.

[26] The price of oil and gas reserves has plunged from about $9/BOE in the first quarter of 1984 to about $5/BOE in the third quarter of 1986. Source: Strevig & Associates, in *Business Week,* Dec. 1, 1986, p. 114.

[27] As of Dec. 31, 1984, from Interstate 011 Compact Commission and National Stripper Well Association, "National Stripper Well Survey, " Jan. 1, 1985.

[28] Ibid.

[29] As of Dec. 31, 1985, from Energy Information Administration, *Advance Summary of the U.S. Crude 011, Natural Gas, and Natural Gas Liquids Reserves 1985 Annual Report,* September 1986, DOE/EIA-0216(85)Ad\ance Summary.

101 nterstate Oi|Compact Corn m ission,op.cit.

[31] Of the two States with the highest stripper production, Texas now allows 1 year and Oklahoma 2 years before a shut-in well must be plugged, The Department of the Interior also has lengthened its grace period to 1 year t'or wells on Federal leases. *Energy Daily,* July 21, 1986, and other dates.

Also, the severe dislocations caused by the sudden price drop have altered operating and other costs and may have affected the business strategies followed by the well operators.

Estimates of production losses generally assume that traditional operating costs and business practices still apply. These estimates will likely overestimate the effect of lower oil prices. The lower oil prices have been accompanied by small but significant reductions in day-to-day operating costs and large reductions in costs for major items such as well reworking. Operators are negotiating with their service companies for lower prices or switching to alternative services. They are cutting labor to the bone and deferring maintenance.[32] In some States, authorities are pressuring utilities to grant lower rates of service to well operators. For example, the Oklahoma Corporation Commission has ordered the State's utilities to develop lower electricity rates for oil wells, with reported rate reductions ranging up to *22* percent.[33] And, in the face of declining oil production and threats of extensive well closures, States may take ameliorative actions such as cutting taxes to prevent the loss of jobs and the other economic hardships that the closures would create.

Before the price drop, stripper well operators generally would abandon wells as soon as the incoming oil revenues could not cover cash costs. Unless fracturing or some other production enhancement treatment (most of which are expensive) could boost production, there was little likelihood that the well would be profitable again soon enough to justify continuing to operate it at a loss. In the current situation, however, many operators are likely to believe that there is a fairly high probability that prices will rise sufficiently quickly, and to high enough levels to justify continuing production for (currently) unprofitable wells. Indeed, many stripper well owners view their wells as a family inheritance, one that has provided the means to keep family farms or educate their children. These owners are especially unlikely to give up their wells in the face of what many see as a short-lived attempt by OPEC to eliminate its competitors, to be followed by an inevitable price hike.

OTA knows of two analyses of the potential stripper oil production lost to low oil prices. One widely quoted analysis was sponsored by the Interstate Oil Compact Commission and conducted by The RAM Group, Ltd. of Oklahoma City.[34] This study first computes the stripper well production at different oil prices in Oklahoma using data obtained for that State's wells, and assumes that other States will sustain the same percentage stripper well production loss at each price level as Oklahoma. The study also assumes that wells will shut down when cash flows become negative, that is, when operating expenses exceed oil revenues.[35]

The results of the study for the United States as a whole are shown in table 29. At a $15 oil price, the study predicts a first year production loss of 277,000 barrels per day (bbl/day), or 3 percent of U.S. production.

The general approach of this analysis seems reasonable given the limited data, although OTA believes that the focus on cash flow and the inability to account for still-continuing changes in operating costs will tend to lead to an overestimate of the likely production loss. Also, the pattern of results as shown in table 29 does not appear realistic. Taken together with the data problems, the problems with the trends shown in the published results may limit the usefulness of the results as the basis for policymaking. OTA's overall objections are explained in more detail in box B.

The second analysis was conducted by the Dallas Field Office of the Energy Information Administration as part of their short-term oil production forecasts.[36] In this analysis, EIA used data on oil, water, and gas production from Dwight's Energy Data, Inc. production tape and Dwight's

32 Of Course, deferring maintenance wi ll cause production problems sooner or later,

33 *Energy Daily,* July 21, 1986.

34 Interstate Oil Compact Commission, "Impact of Decreasing Crude Oil Prices on Stripper Oil Wells, Production, and Reserves," The RAM Group, Ltd.

35 William Talley, President, The RAM Group, Ltd., personal communication, 1986.

36 Energy Information Administration, *Short-Term Energy Outlook July 1986, DOE/EIA-0202(86/3 Q),* August 1986, updated by letter of Apr. 7, 1987, John Wood, Dallas Field Office, EIA to Steve Plotkin, Office of Technology Assessment.

Table 29.—Effect of Falling Oil Prices on Stripper Wells*

Oil price ($/bbl)	Percentage of stripper wells abandoned	Number of stripper wells abandoned	Production lost first year (b/d)	Gross value of production lost first year (thousand $)	Total reserves lost (million bbl)
$10/bbl	40.8	184,547	638,046	2,328,869	2,610.880
$15/bbl	22.5	101,958	277,090	1,517,065	733.812
$18/bbl	15.6	70,370	175,746	1,154,654	278.490
$20/bbl	10.0	45,390	106,586	778,077	92.783
$23/bbl	5.0	22,446	49,756	408,618	16.862
$25/bbl	0.0	0	0	0.000	0.000

* Based on 452,543 stripper wells as of Jan. 1, 1985, and average production of 2.8 bbl/day.

SOURCE: Interstate Oil Compact Commission and Ram Group Ltd. , 1988, in Oil *and Gas Journal, Mar 3, 1986, page 38*

Petroleum Data System, and published well operating cost data[37] to construct a distribution of stripper wells according to their oil production (and, given an oil price, their revenues) and operating expenses, by State. The primary data problems were the unavailability of water production data (critical to determining well operating costs) for some States and the overaggregation of much of the production data, some of which was available only at the field level.

The EIA analysis estimates that first year production losses will be *148,000* bbl/day at an oil price of$15/bbl, with additional losses of 77,500 bbl/day a year or two in the future as more wells are abandoned when major expenditures become necessary, for a total loss of 225,000 bbl/day. At $18/bbl, first year losses are 85,000 bbl/day, with additional losses of 4,300 bbl/day later, yielding a total loss of 89,300 bbl/day. For the $15/bbl case, the major State losses occur in Texas (73,900 bbl/day total, or 18 **percent of State stripper well production), California (46, 100 bbl/day, or 29 percent), Louisiana (15,400 bbl/day,** or 57 percent), Oklahoma (1 3,400 bbl/day, or 5 percent), New Mexico (1 2,400 bbl/day, or 30 percent), and Kansas (6,200 bbl/day, or 5 percent).

Overall, the EIA estimates of first year stripper well losses are about half the IOCC/RAM estimates. However, although the difference between the two sets of estimates may appear great, in OTA's view the differences in the national total are not at all unusual given the lack of data.

[37]V.T.Funk and T.C. Anderson, Dallas Field Office, Energy Information Administration, *Costs and Indices for Domestic Oil and Gas Field Equipment* and Production Operations *1985*, DOE/EIA-0185(85), April 1986.

The EIA analysis' wide State-to-State differences among the fraction of total production that is abandoned is, however, quite different from the RAM analysis.

More recently, an IOCC survey of California, Kansas, New Mexico, North Dakota, Oklahoma, Texas, and Wyoming indicated that 110,000 wells in these States, with 307,000 bbl/day of oil production, were shut in during 1986, with 12 percent of the wells permanently abandoned. * These values do not break out the production lost solely because of low oil prices (each year, thousands of wells are abandoned even at high oil prices), and thus they are not strictly comparable to the projections above. However, most of the production loss is likely to be attributable to the price drop, and the survey appears to add credibility to the (higher) IOCC projections. However, the state-by-state breakdowns show a wide variation among the States in the percentage of production lost (range: 3.6 to 11.1 percent), contrary to the assumption of interstate uniformity in the IOCC analysis.

As noted above, warnings about impending reductions in stripper well production invariably include the prediction that the reserves associated with the abandoned wells will be lost, either forever or until oil prices reach $50 to $100 per barrel. This is undoubtedly true for older wells that have depleted a major share of their original recoverable oil, or for newer wells that have been fractured and have already passed through the initial production surge associated with fracturing, **assuming the use of current well abandonment techniques and well drilling technology.**

***Oil** *and Gas Journal*, Apr. *27,* 1987, p. 24.

Box 8.—Potential Problems With the Interstate Oil Compact Commission/The RAM Group, Ltd. Estimate of Stripper Well Production Losses Due to Low Oil Prices

1. The significance of the consultant's assumption that the stripper wells in other States will respond identically to Oklahoma's is not known. This assumption was forced on the consultant by the available data. The Energy Information Administration analysis projects significant differences among the State-by-State responses.
2. The decision to base the analysis on cash flow appears likely to overestimate the first year production loss. Continuation of the low prices should eventually lead to a loss of this magnitude, however, assuming the remainder of the analysis is correct. Prior to the recent price drop, well shut-in decisions generally were made on the basis of cash flow, because a negative cash flow signaled a production drop below the profitable range. OTA believes that, in the current environment, many operators will be willing to continue production at a small loss for a few years—rather than abandon their investment—in the hope that oil prices will go back up to profitable levels.
3. Analyses of this kind do not take into account the actions taken by operators and governments to avoid well abandonments. Operators are cutting costs by bargaining with suppliers, cutting labor, and deferring routine maintenance. Governments can take such actions as cutting taxes and exerting pressure on regulated suppliers to the operators (e.g., electric utilities). However, OTA notes that many of our industry contacts do not believe that oilfield operating costs can be cut substantially.
4. Of more significance than the above potential problems, the estimated rates of production lost per well do not appear at all realistic. According to table 29, the average production lost per shut-in well increases markedly as a higher and higher percentage of all wells are lost (i.e., as prices drop lower and lower). At very small production losses, the average shut-in well had produced at a rate less than 80 percent of the U.S. average stripper well production. As prices drop, and as the lower prices force some of the better producers to shut in and the percentage of wells lost increases, the average production lost per shut-in well increases steadily, reaching 1.25 times the U.S. mean production rate at a 40 percent loss and apparently still accelerating upwards.

   A possible physical explanation for this pattern is that, with a small decline in prices, the first wells to be abandoned are those with very low production rates and high fixed costs. At still lower prices, a relatively large group of stripper wells with high production rates but high costs—most probably because the wells produce a lot of water—are abandoned. Abandonment of this group of wells will pull up the average production lost per shut-in well. Finally, at even lower prices, wells with low production rates and relatively low costs are shut in, pulling down the average production rate lost per abandoned well.

   This type of distribution of stripper wells is theoretically possible but appears unlikely. OTA believes it is more likely that, as prices drop to lower and lower levels, the average (lost) production of the wells being shut in will begin (with only a few wells shut in) considerably below the mean U.S. stripper production rate and gradually (as more and more wells are shut in) rise to the mean production rate, equaling it when all of the wells are abandoned. This distribution is based on the observation that, in general, the lowest producers will tend to have the highest per barrel production costs and thus tend to be shut in first. (There will, of course, be lots of individual exceptions to this, such as higher producing rate wells that also produce lots of water and thus have high per barrel operating costs. These seem unlikely to be able to pull the average (lost) production of the shut-in wells way over the mean, however.) Consequently, OTA has severe reservations about the shape of the production curve implied by table 29, and is skeptical about the validity of the analysis.

However, much of the drilling during the recent boom was aimed at geologic targets that promised stripper-type production levels. This implies that, where a substantial level of depletion has not occurred, a return to the economic conditions of the late 1970s to early 1980s may allow recovery of the "lost" reserves through new drilling. in addition, previously there was no incentive to devise well plugging techniques that would allow a relatively inexpensive reentry into the well. If such techniques could be devised, or if advances in drilling technology substantially decreased drilling costs, stripper abandonment could be reversed more readily.

The Nature of the Resource Base

The nature of the oil exploration and development prospects available to the industry and, in particular, the distribution of high- and low-cost oil is a primary determinant of future supply, and a critical uncertainty. Future development prospects, for example, range from a variety of enhanced recovery operations, to infill drilling and extensions, to high cost development in the Arctic and deep offshore; exploration prospects similarly range from new pools in old fields, to large numbers of small onshore fields, to the search for giant fields in difficult frontier areas. There is substantial controversy about the number of viable prospects in each category, and thus a similar degree of controversy about the true replacement costs of oil and the likely supply response at any price.

There are three types of prospects that represent the critical sources of uncertainty in considering the ability of the remaining U.S. oil resource base to support continuing development and production, especially in a low price environment. These are:

- the range of conventional drilling prospects that create field growth,
- exploration for small fields. and
- exploration for large fields including frontier giants.

The Prospects for Continued High Levels of Field Growth

The basic argument that continuing low oil prices will devastate future U.S. oil production hinges on the conception of the U.S. oil resource base as a mature, high cost resource base. According to this concept, most of the United States' low-cost oil has been found and produced; increasingly, new production must come from oil finds in hostile, expensive frontier areas or from high technology, high cost enhanced oil recovery operations, and neither of these sources can be developed at world oil prices of $15/bbl.

The recent history of the oil industry's efforts to regenerate the United States' oil reserves implies that this conception of a high cost resource base may be somewhat misleading. It is true that the geographic and technological frontiers—complex enhanced oil recovery technologies, drilling in the deep waters of the Outer Continental Shelf, onshore drilling to depths well below 15,000 feet, and exploring and producing in the extreme conditions of the arctic–have captured the major publicity. However, the great majority of oil reserves added to the U.S. inventory during recent times has come from non-glamorous sources. Fully 70 percent of the total U.S. reserve additions during 1979 to 1984 came from drilling thousands and thousands of extension and infield wells in the United States' large inventory of discovered oilfields. If Alaska and the offshore are subtracted, extensions and infield drilling from previously discovered fields accounted for 76 percent of reserve additions during the last decade, up from 66 percent during the 1950s and 1960s.[38] The potential for continuing high rates of reserve growth in discovered oilfields at relatively low cost is one key to the future of U.S. domestic oil production in a low price environment.

When new fields are discovered, their reserves are "booked" according to the geologic information gained from the discovery well and other initial delineation wells. For most fields, the initial estimates of reserve volumes are associated

[38] W.L. Fisher and R.J, Finley, "Texas Still Has Big Resource *Base,"* *Oil and Gas* journal, June 2, 1986, pp. 57-69.

only with those wells drilled in the discovery year. Afterwards, as the field is developed, the reserve estimates change, and most often grow. Reserves grow as additional wells are drilled to delineate the field's outer boundaries (extension wells) or to find additional reservoirs associated with the field (new pool tests). If prices rise or more efficient recovery technologies are developed, areas of the field that were previously subeconomic will be developed with additional development wells. Further knowledge of the reservoirs gained by production histories may lead to revisions in the reserve estimates, or may indicate that the existing well spacing is not recovering all of the recoverable oil, leading to an infill drilling program that can add to total recovery and thus to reserves. Rising prices may change the "abandonment" point (when the well is shut in because operating expenses overwhelm revenues) of the existing wells, leading to further positive reserve revisions. In some cases, for example when the reservoir rock has low permeability, well stimulation techniques such as fracturing may allow increased recovery, further adding to reserves. Finally, the portion of the oil-in-place that would not normally flow to the wellbore might be recovered with enhanced oil recovery (EOR) techniques that loosen the oil's bonds to the rock by heating or chemical means or that drive the oil to the well using a fluid or gas.

How will U.S. fields grow in the future? The historical record of reserve additions suggests that older oilfields have "grown" by a factor of about 7 to 8 and gas fields by a factor of about 4 over the 60-year period from 1920 to 1979.[39] Thus, the potential for further reserves from field growth will depend on the extent to which these old fields will continue to grow, and the extent to which more recently discovered fields, and new fields, will duplicate the growth potential of the older fields.

The primary argument for a relatively high reserve growth in new fields and continuing growth in older fields is that the volumes of "mobile oil''—oil that can be recovered with conventional drilling and well stimulation techniques–have been consistently underestimated, and that large amounts of this oil can be recovered with more intensive drilling even in the Nation's most mature oil basins. Proponents of this view point to the 1978 USGS estimate, based on a statistical analysis of past field growth, of potential reserve growth in Texas. The estimated ultimate growth of 4 billion barrels has already been virtually achieved in the **8 years since the original estimate was made,[40] and growth is continuing at a steady pace.**

A high estimate of the volume of mobile oil in existing oilfields is based on the proposition that the so-called "macroscopic" heterogeneity of hydrocarbon reservoirs is "the least studied, the least known, and the most difficult of the . . . types of variations to define with precision,"[41] and is often ignored or severely underestimated. Macroscopic heterogeneity refers to changes in reservoir characteristics that can partially or wholly isolate significant volumes of the reservoir, extending a few acres a really or a few feet vertically, from the remainder of the reservoir. Isolated compartments or layers of this nature would be obvious targets for infill drilling and multiple-zone completions.

A recent study of the potential volumes of mobile oil **over and above that recoverable with normal field development suggests a "target" on the order of 80 billion barrels of mobile oil-in-place for the total United States, with** an unknown but possibly high fraction of that being economically recoverable.[42] Continued advancement of the state-of-the-art of reservoir modeling and engineering, it is hoped, will allow infill drilling and well stimulation programs to be undertaken with relatively low technical risk. Assuming that this is so, the potential profitability of investments aimed at recovering additional mobile oil will depend on the trade-off between drilling and stimulation cost, on the one hand,

[39] D. H. Root, "Estimation of Inferred Plus Indicated Reserves for the United States, " app. F in G. L. Dolton, et al *Estimates of the Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States*, U.S. Geological Survey Circular 860, 1981.

[40] Lewin & Associates, Inc., *Reserve Growth and Future U. S. Oil Supplies*, prepared for U.S. Department of Energy, June 30, 1986.

[41] W.L. Fisher and W. E. Galloway, "Potential for Additional Oil Recovery in Texas, " Geological Circular 83-2, Bureau of Economic Geology, The University of Texas at Austin, 1983.

[42] Lewin & Associates, Inc., op. cit.

and the additional oil volumes recovered. The referenced study[43] gives some examples of infill projects that appear, on the basis of the reserves/ well recovered, to have some economic potential even at today's low oil prices if drilling costs can be sustained at current low levels. However, there is little guarantee that these examples are reflective of the actual resource potential; it is worth noting that the analysts primarily responsible for raising the issue of mobile oil are acutely pessimistic of the potential for continuing high rates of field growth at current low prices .44

To place this potential for field growth in further perspective, it is important to note that there is by no means a consensus that heterogeneities within known field boundaries will yield large quantities of additional oil. Controversy about the ability of infill drilling to add substantively to reserves—rather than just to speed production—has continued for years. In 1967, a massive study of 312 reservoirs by the American Petroleum Institute's Subcommittee on Recovery Efficiency could not determine a relationship between well spacing and ultimate recovery .45 And a recent review i n the *Journal of Petroleum Technology* reiterated that:

> A key question in the debate is: "What portion of the additional oil recovered by infill drilling results from accelerated production of old reserves and what portion results from increased reserves?" This relationship is hard to quantify, and assessments differ.[46]

OTA's past work supports an optimistic view of the potential for infill drilling to add significantly to recoverable oil reserves. In a previous study, OTA examined the question of infill drilling's ability to add substantially to domestic gas reserves.[47] As part of this examination, OTA conducted a series of interviews with persons familiar with infill drilling and reservoir analysis. OTA found a definite majority in favor of the view that infill drilling could add substantially to gas reserves, not only in fields that were widely known to be heterogeneous, but also in fields that were generally considered to have relatively homogeneous, blanket-type reservoirs. This majority favored the view that recent experience supported the view of oilfields as more heterogeneous than previously understood, that this led to a substantial potential for increasing ultimate recovery through carefully selected infill drilling, and that this experience applied to gasfields as well.

Aside from the technical argument about reservoir heterogeneity, many producers argue that the large amount of infill drilling conducted in the 1970s and early 1980s has used up most of the infill potential in the Nation's stock of older fields, or at least that portion of the potential that was economic at the earlier oil prices. Furthermore, these producers argue that today's "less favorable" drilling economics reduce the current infill potential still further. The investigations of infill potential have not as yet produced detailed evaluations of the distribution of drilling prospects that would allow an economic analysis. As implied by OTA's analyses of some limited drilling ventures, however, low risk drilling prospects may be less attractive to producers at prices of $14/bbl or so than were identical ventures a few years ago, but prices closer to $18 or $20/bbl could turn this around; lower drilling costs have lowered significantly the "minimum required price" for most prospects.

Pessimists about the role of future field growth also believe that **new** fields may have less ultimate growth potential beyond their first year reserve estimates than the older fields. For one thing, the size distribution of new fields is weighted more heavily towards the smaller end of the spectrum, both because the largest fields tended to be discovered first and because recent higher prices had allowed fields to be developed in a size range that would have been termed uneconomic in earlier times. Most analysts would expect field growth to be highest for large fields, because the first year's discovery and delineation wells will discover more of a small field's reserves

[43] Ibid

[44] Fisher and Finley, Op. cit.

[45] A. F, van Everdingen, letter to George Fumich, Department of Energy, January 1980.

[46] "Industry Weighs Infill Drilling and EOR in Planning To Maximize Ultimate Production," *Journal of Petroleum Technology,* November 1983,

[47] U.S. Congress, Office of Technology Assessment, Energy and Materials Program, *Staff Memorandum on the Effects of Decontrol on Old Gas Recovery,* February 1984.

than they will of a large field's reserves.[48] Also, the location of many recently discovered fields in the offshore or frontier areas far from established pipelines demanded better delineation of field size before the reserves could be booked and transportation systems developed.[49] Our improved seismic technology and understanding of reservoir behavior also would tend to yield better —and generally higher—initial reserve estimates for newly discovered fields.

Exploration for Smaller Fields

A second important resource issue concerns the extent to which smaller fields–many of which might have been considered "dry" under previous economic/technological conditions—could provide substantial reserve additions, and production, in the coming decades. This issue hinges on both the magnitude of resources contained in small fields and the economic viability of pursuing small fields as a major exploration target.

Historically, small fields have played a minor role in oil and gas development. Fully 80 percent of all discovered oil and gas resources were found in fields of at least 50 million barrels of oil equivalent, whereas 1 million BOE is considered the cutoff point for "significant" field size. The size distribution of discovered oil and gasfields is shown in figure 7. As shown in the figure, as one moves to smaller field sizes, the number of discovered fields increases steadily down to about AAPG Field Size D and then rapidly levels off. At least a portion of this "truncation, " or leveling off, of the field size distribution is undoubtedly due to past economics. Many small finds were too small to be economically developed and consequently were reported as dry holes rather than added to the historical record as a class D or E field. Also, explorers may have been quick to abandon the search for additional fields in a productive area when it appeared that most or all remaining finds would be small. Thus, it has been argued that a field size distribution of **all** fields, discovered and undiscovered, would look more like the dark bars in figure *8.* This distribution assumes that the progression of field sizes established by the discovered larger fields would continue for the smaller field sizes if economics did not intrude.

Arguments about the number of small fields that may be available for exploitation are necessarily speculative because they are based on extrapolation only; no petroleum basin has experienced the intensity of drilling that would be required to find the postulated number of small fields. Some past experience with field size distributions supports the general principal that at least part of the dropoff in the number of small fields is caused by economic rather than geologic forces, however. For example, USGS studies of field size distributions in the Gulf of Mexico, the Denver Basin, and the Permian Basin show that the "truncation point" of the distribution moves to larger field sizes when exploration and development costs are higher, which would be expected if the truncation were economically determined.[50] On the other hand, some analysts argue that certain types of petroleum basins—containing a significant portion of U.S. petroleum resources—show a dropoff in the number of discovered fields at a field size level that is too high to be explained by economics.[51]

If the most optimistic field size distribution postulated in figure 8 is correct, or largely correct, there may be a substantial oil and gas resource residing in small undiscovered fields. in many instances, these fields would be in producing areas with an existing pipeline and processing plant infrastructure, so development costs would be low. However, the small size of these fields implies that the costs of discovery will be

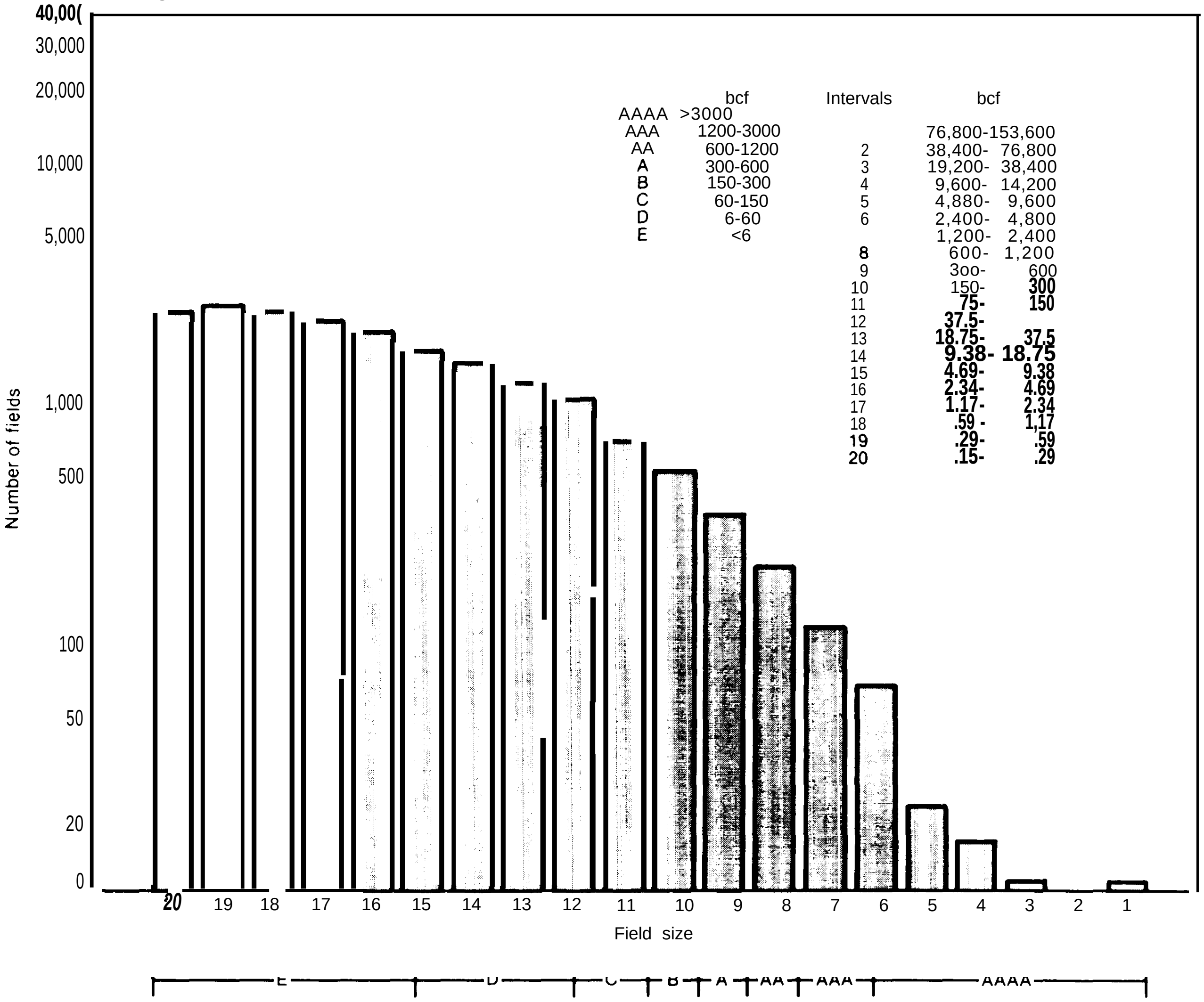
[48] One interesting though speculative counterweight to this argument is the observation that reserves found in small fields have more "boundary" than an equivalent magnitude of reserves in large fields (small volumes have a larger ratio of circumferential area to volume than large volumes), and thus may have more potential for extensions. Source: Charles Matthews, Senior Consultant, Shell Oil Co.

[49] However, the proportion of U.S. oil production from offshore areas has been relatively stable for the past two decades; the major period of growth was from the middle 1950s to the late 1960s. This somewhat weakens the lower field growth argument for oil. On the other hand, the proportion of offshore gas production has increased steadily from the 1950s to the present.

[50] J. H. Scheunemeyer and L.J. Drew, "A Procedure To Estimate the Parent Population of the Size of Oil and Gas Fields As Revealed by a Study of Economic Truncation, " *Mathematical Geology*, vol. 15, No. 1, 1983.

[51] R. Nehring, *The* Discovery *of Significant Oil and Gas Fields in the United* States, R-2654/I-USGS/DOE, RAND Corp., January 1981, pp. 78-94. Excursis, "The Distribution of Petroleum Resources by Field Size in the Geologic Provinces of the United States. "

Figure 7.—Size Distribution of Discovered Oil and Gas Fields in the Lower 48 States



SOURCE: R. Nehring. "Problems in Natural Gas Reserve, Drilling, and Discovery Data," contractor report to OTA, 1983

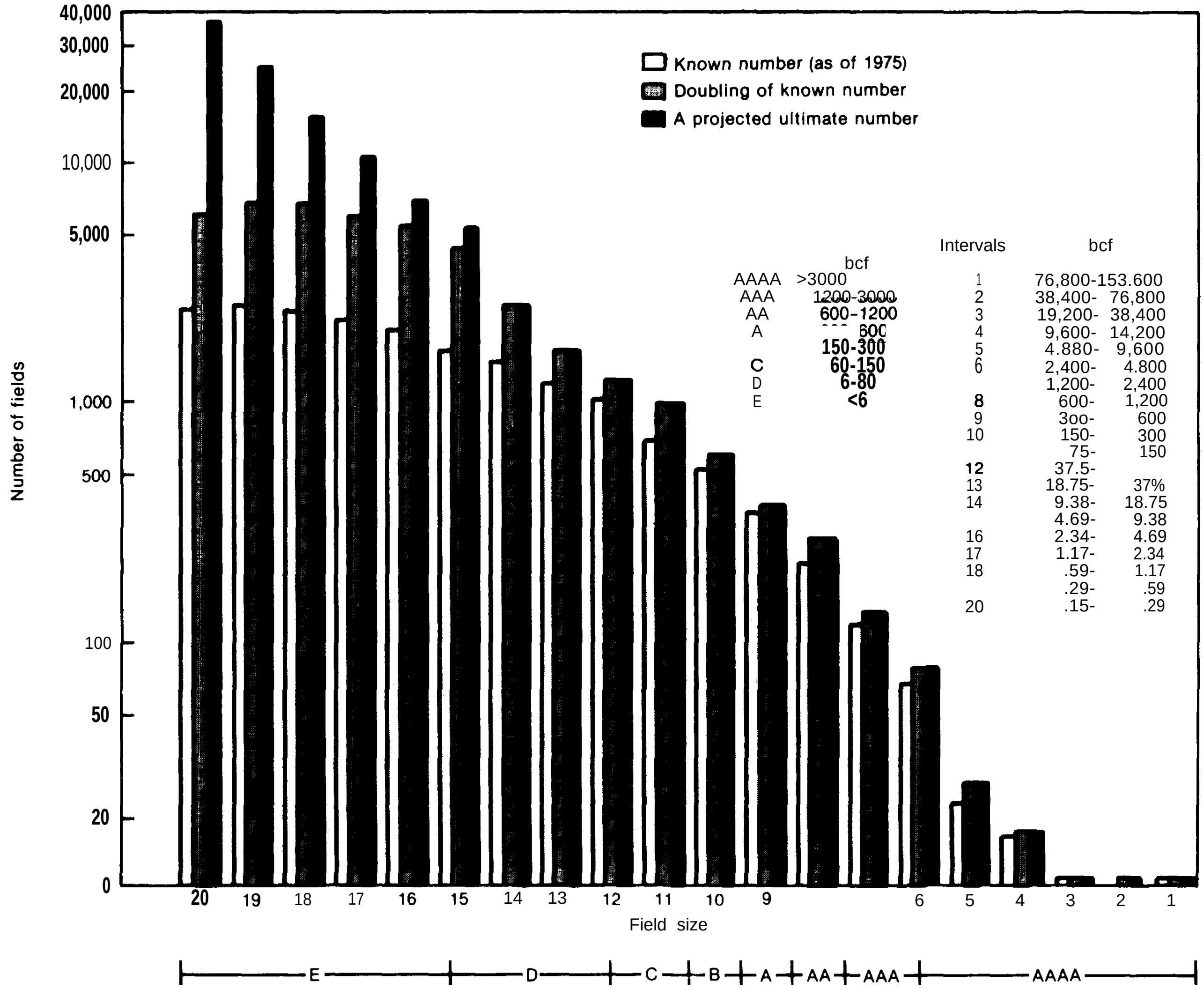
high, assuming historic ratios of dry holes to successful new field wildcats. Past studies of the economics of oil and gas recovery from the Permian Basin show that the number of exploration wells that will be drilled is extremely sensitive to oil prices, with as many as *38,000* exploration wells drilled at $40/BOE wellhead prices but only 5,000 drilled at a $10/BOE price.[52] Consequently, the possibility that substantial quantities of oil can be recovered from small fields at low oil prices depends primarily on the potential to lower the costs of discovering these fields by improving discovery technology and raising the success rate of exploratory drilling.

Finding New Large Fields

A third key to the continuation of high rates of reserve replenishment and the maintenance of long-term oil production is the extent to which U.S. oil explorers can continue to find large new fields at rates comparable to those of the past dec-

[52] U.S. Geological Survey, *Circular 828—Future Supply of Oil and Gas From the Permian Basin of West Texas and Southeastern New Mexico,* Interagency oil and Gas Supply Project, 1980, It should be noted, however, that the economic model used in this study does not capture the effect on drilling rates and resource economics of the dependency of drilling costs on 011 prices

Figure 8.—Known and Projected Size Distributions of Discovered Oil and Gas Fields in the Lower 48 States



SOURCE: Office of Technology Assessment, based on data from R. Nehring, "Problems in Natural Gas Reserve, Drilling, and Discovery Data," contractor report to OTA, 1983 ade and a half, and whether any of the few remaining prospects of extremely large size will be successful.

Since the early 1970s, the industry has discovered between *200* and 250 "significant" oil and gas fields (of size greater than 1 million BOE) every year.[53] In addition, the per well "finding rate" of exploratory drilling, which had been falling for decades, stabilized during the same time period and now appears to be relatively flat at about 470,000 BOE per exploratory well.[54] Nevertheless, this finding rate has not been sufficient to allow new field discoveries to play a really crucial role in reserve replacement during the past decade. For example, during 1979 to 1984 new field discoveries (with expected field growth) have added only about 2.4 billion barrels of reserves to the U.S. total, out of a total of approximately 15 billion barrels added during this period.[55] The reason for this is that very few of the new fields found have been the "giants" that played such a major role in the United States' emergence as an oil superpower. I n recent years, the search for very large fields has been disappointing, with the well-publicized Mukluk dry hole being only one of a string of failures. Recent exploration efforts in the Gulf of Alaska, East Coast Jurassic Reef Play, Georges Bank, Beaufort Sea, St. Georges Basin, and the Norton and Navarin Basins have been either outright failures or have produced far fewer discoveries than anticipated, and recent assessments of U.S. recoverable petroleum resources are said to have severely downgraded prospects for frontier oil and gas. During the past decade, only six "one billion BOE''-size plays have been discovered–''the Barrow Arch oil and gas trend in Alaska, the Northwest Santa Barbara Channel oil trend in California, the overthrust Mesozoic oil and gas play in Utah and Wyoming, the Pliocene trend offshore Louisiana, and the Pleistocene Shelf and Slope trends offshore Louisiana and Texas."[56]

In the continuing search for large fields, the intersection of resource base issues and prospect economics comes into sharp focus. There still are sufficient geologic opportunities to continue the "baseline" discovery of 200 to 250 significant fields yearly **if the exploration effort aimed at finding** these fields holds up . . . but it is precisely in the area of exploration for new fields that industry analysts are most pessimistic about continuing the previous level-of-effort. Many companies are telling their stockholders that the focus of their reserve replacement efforts will be shifting away from exploration in the United States and towards field development. On the other hand, the "low oil price" run of the Gas Research Institute's Hydrocarbon Model, discussed elsewhere, indicated that, on a resource economics basis, exploratory drilling could hold up quite well. An accurate forecast of the level of exploratory drilling is critical to obtaining a credible forecast of reserve replacement and future U.S. production.

For the very most promising areas—those that appear to have real prospects for supergiant fields–arguments about current resource economics may be somewhat meaningless because the only remaining areas with such promise are in the deep offshore and Arctic regions, with time lags between leasing and production of a decade or more. It does not appear likely that the more aggressive majors would pass u p opportunities to explore in these areas, because oil prices at the time of any production are unlikely to bear any relationship to today 's.

Two such prospective areas critical to longer term U.S. oil production potential are the unleased California offshore and the coastal plain of Alaska's Arctic National Wildlife Refuge (ANWR). Both these areas boast structures that could hold reserves of supergiant size, although the recent Mukluk disappointment should serve as a warning that there often is a long distance between potential and reality when it comes to petroleum

[53] R Nehring OTA Workshop on the Effects of Lower Oil prices on U.S. Oil Production, June 25-26, 1986.

[54] T. j, Woods and P.D. Holtberg, "Hydrocarbon Activity in an Era of Low Oil Prices," Society of Petroleum Geologists Paper 15355, 1986.

[55] Lewin & Associates, inc., *Reserve Growth and Future U.S. Oil Supplies,* op. cit., based on Energy Information Administration, U.S. *Crude VII, Natural Gas and Natural Gas Liquids Reserves, 7984 Annual/ Report, DOE/E IA-021 6(84),* September 1985,

[56] Com m ittee on U.S. Oil and Gas outlook, National petroleum Council, *Factors Affecting U.S. Oil and Gas Outlook,* draft final report, Nov. 3, 1986, quoted with permission.

resources. Both areas are extremely controversial leasing targets as well, California because of the remembrance of the Santa Barbara spill and a longstanding aversion among many of the State's residents to offshore development, and Alaska because of the wildlife and wilderness Issues.

Because the ANWR is considered by many geologists to represent the most prospective remaining frontier area in the United States, and because it is today embroiled in controversy, OTA thought it useful to discuss it here in greater detail.

The Arctic National Wildlife Refuge

ANWR was established in the extreme northeast corner of Alaska in 1960 as the Alaska National Wildlife Range. It is the part-time residence of approximately 180,000 caribou and millions of waterfowl and home to such species of animals as musk oxen, Dall sheep, wolves, arctic foxes, wolverines, brown bears, polar bears, and arctic ground squirrels and other rodents. Originally comprising 8.9 million acres, the Range was expanded in 1980 to 19 million acres (about half the size of the State of Washington) with the adoption of the Alaska National Interest Lands Conservation Act (ANILCA). In all, ANILCA added more than 106 million acres to Federal conservation systems in Alaska. ANWR was redesignated as a refuge at this time, and 8 million acres of it were added to the wilderness system. At the behest of Senator Stevens of Alaska, 1.5 million acres on the coastal plain, which were considered to have significant oil and gas potential, were set aside for further study. The area is known as the 1002 area, since Section 1002 of ANILCA required the Secretary of the Interior to prepare a report to Congress on the fish and wildlife resources and oil and gas potential of the area and to recommend whether further exploration, development, and production of oil and gas should be allowed. A draft of the study was released in December 1986, and the final report was delivered in April 1987.

Petroleum Resources

The western boundary of ANWR lies approximately 60 miles east of the giant Prudhoe Bay oilfield—the largest in the United States. Prudhoe Bay was discovered in 1968 and was estimated to contain over 10 billion barrels of recoverable oil. Once in full production, the field produced about 1.5 million barrels of oil daily —approximately 12 percent of the crude oil processed through U.S. refineries each day. The so-called 1002 area of ANWR, which is being considered for possible future mineral leasing, is located in the coastal plain as is Prudhoe Bay and shares many of the geological features of that highly productive field. For this reason it is believed that large recoverable oil and gas resources may also occur in ANWR.

All of the oil production from the Prudhoe Bay and the smaller adjacent Kuparuk River field is from sandstone rocks of the Ellesmerian sequence. At the time the Ellesmerian sequence was formed, conditions prevailed for the accumulation of potential petroleum-producing sediments which are believed to have later undergone transformation into hydrocarbons. The porous Ellesmerian sandstone is believed to have permitted the petroleum to migrate through the formation until intercepted and trapped by impervious, folded basement rocks. Geologists believe that the petroleum potential of the 1002 area will largely depend on the extent that the Ellesmerian sequence underlies the ANWR coastal plain.

Other parts of the 1002 area are underlain by the younger Brookian sandstone sequence which is producing oil in the Endicott oilfield offshore Prudhoe Bay and in the Point Thomson field near ANWR. A number of offshore wells in the Canadian portion of the Beaufort Sea north of Mackenzie Bay are also producing oil from Brookian rocks. Geologists expect fewer sealed traps to exist in areas underlain by the Brookian sequence, hence the prospect for large quantities of petroleum to exist in such areas is less than for the Ellesmerian sequence. Oil seeps on the coast near Kaktovic, Point Thomson, and Demarcation Point are additional evidence of oil potential in the 1002 area.

In preparing its Section 1002 resource report for Congress, the Department of the Interior collected seismic information over 1,300 miles of the ANWR coastal plain. Interpretation of the seismic data by the U.S. Geological Survey identified 26 potential hydrocarbon traps. Underground features or structures in the northwest quarter of the 1002 area appear to dip gently to the northeast with comparatively little deformation, in a manner similar to the Prudhoe Bay structures. The southeastern portion of the 1002 area is much more complex and contains many folded and faulted structures. Complex geology of this kind makes interpretation of the existing seismic data more difficult, but several very large structural closures that could contain oil have been identified. Similar overthrust structures in the Canadian and U.S. Rocky Mountains have produced significant amounts of oil and gas.

The 26 identified possible hydrocarbon traps are located in 7 plays (areas with similar geologic characteristics that share common geological elements). Resource estimates for the 1002 area are based on geologists' judgment about the geologic factors necessary for formation and retention of oil and gas and evaluation of the properties that could determine the size of a petroleum deposit. Based on such expert judgment, statistical analyses are used to determine probability estimates of possible in-place oil and gas resources. Finally, economic analyses are applied to the geological estimates to determine the volume of oil that could be removed from the deposit using current technology.

Because of the inexactness of resource estimates based largely on seismic data, geological analogies, and future cost-price assumptions, petroleum resource estimates such as those assigned to the 1002 area should be considered as "relative indicators" for comparison with other potential resource-rich areas rather than as absolute volumes of recoverable petroleum. A shift in assumed oil prices can significantly change the economics of the minimum field size, which in turn can increase or decrease estimates of recoverable oil. Changes in the geologic assessment can dramatically change the estimates of economicall$_y$ recoverable oil. In the final analysis, estimates of both in-place and recoverable oil and gas resources should be considered more "guesstimates" than scientific assessments. Exploratory drilling remains the only certain and totally objective way to determine the presence and extent of oil and gas resources.

it is clear that ANWR ranks high among the range of potential petroleum-producing prospects remaining in the United States either onshore or in the Outer Continental Shelf. Even though the resource potential for the 1002 area is considered to be great, however, USGS geologists give odds of only one in five (20 percent) that a commercial discovery will be made in the entire area should it be explored. This so-called "marginal probability" for discovering an economic deposit seems surprisingly low for an area with such favorable geological attributes and demonstrated oil production close by. However, the National Petroleum Reserve in Alaska (NPRA), which lies to the west of Prudhoe Bay about 50 miles in a similar coastal setting, has thus far failed to yield a commercially important oilfield after substantial drilling, although the U.S. Geological Survey estimated in 1979 that 7 billion barrels of oil in-place (not gauged by its recoverability) could be expected.

DOI's resource estimates for the 1002 area of ANWR are shown in table 30.

**Table 30.—Estimated Oil and Gas Resources in the Arctic National Wildlife Refuge Section 1002 Area (recoverable volumes based on oil price of $33/bbl,** 1984$)

	Oil (billion barrels)			Gas (trillion cubic feet)		
Type of estimate	95 "/0	Mean	5%	950/0	Mean	5%
In-place resources[a]	>4.8	>13.8	>29.4	>11.5	>31.3	>64.5
Conditional recoverable[b]	>0.6	>3.2	>9.2	—	—	—
Recoverable risked mean[c]	—	>0.6	—	—	—	—

[a]Total volume below the ground of which perhaps 25 to 35 percent may be recovered economically An estimate based wholly on geological factors

[b]Economically recoverable 011 that may be available if an economic deposit occurs The odds are one in five (20 Percent) that this will be the case

cThe estimate of Conditionally Recoverable 011 reduced 80 percent to allow for the possibility that none may occur

SOURCE: U S Geological Survey

Undiscovered oil and gas estimates frequently result in confusion during debates over resource development on public lands. Petroleum geologists express oil and gas resource statistics in three different ways:

1. "In-Place" resources–the total volume of petroleum expected to occur without regard to economic recoverability or the chances that petroleum may not occur at all.
2. "Conditional, Economically Recoverable resources''—the volume of oil or gas that could be recovered under assumed economic conditions and levels of technology, ignoring the possibility that resources may not occur at all.
3 "Recoverable Risked Mean''–the conditional economically recoverable resource estimate adjusted downward by the probability that oil or gas may not occur in commercial quantities in the area.

Each type of estimate has its uses, but one must be careful about the interpretation lest he be misled. In-place resource estimates have not been subjected to the vagaries of economic and technological assumptions and predictions that determine how much of the oil in place can be economically recovered. Should oil actually be discovered in economic quantities in the ANWR 1002 area, in-place estimates can provide an insight to a field's ultimate potential as technologies or economics improve. This is important for long-range planning in anticipation that drilling and production technologies may improve or that energy prices may change in the future.

Conditional economically recoverable oil and gas estimates, on the other hand, provide information useful in determining the economic and strategic potential of a prospect based on existing or foreseen economic and technological trends. It provides a basis for evaluating the worst-case scenario for environmental and socioeconomic impacts that could result from development of the ANWR 1002 area should commercially important discoveries occur. The chance that commercial-scale deposits may not occur in the area is not a factor considered in the conditional estimate.

Risked mean economically recoverable oil and gas estimates factor in the possibility that no economically recoverable resources exist in the 1002 area. This reduces the conditional estimates of recoverable oil in proportion to the risk that no commercially recoverable oil exists in the area. In the case of ANWR, 3.2 billion barrels of economically recoverable **oil is reduced** by 80 percent (the probability that no commercial discoveries of oil will occur in the 1002 area) to determine the risked mean estimate of about 640 million barrels of oil. Natural gas was not considered currently economically recoverable, hence no estimates of gas were included in either the conditional and risked mean estimates, although a mean of 31 trillion cubic feet are estimated to occur in-place.

The risked mean resource estimate accounts for the realities of exploring for oil and gas in frontier regions where few exploratory or stratigraphic wells have been drilled. It is most useful for estimating regional and national oil and gas resources, where estimates of the potential resources in several unexplored areas must be combined, or for comparing areas. In the offshore frontier OCS areas, the marginal probability that oil might occur ranges from one percent in the Hope Basin to 70 percent in the Beaufort Sea off the north coast of Alaska. Why the marginal probability of oil in commercially recoverable volumes is 20 percent for the ANWR 1002 area and increases to 70 percent in the Beaufort Sea offshore area immediately north of ANWR, where even less is known about the subsurface geology, was not addressed in the U.S. Geological Survey's resource estimates of the 1002 area.

ANWR is one of the few remaining unexplored major onshore prospects in the United States. Although much of Alaska remains unexplored for oil and gas, ANWR holds the most promise for the discovery of giant fields. Most of the other highly prospective oil and gas areas are offshore in the Outer Continental Shelf. When risked mean resource estimates of oil for the ANWR 1002 area are compared with the frontier OCS oil and gas lease planning areas, it ranks third, behind the Navarin Basin (1.3 billion barrels), and the Beaufort Sea (0.9 billion barrels). Furthermore, when the results of recent drilling disappointments in the Navarin are formally factored into resource calculations, ANWR might rank still higher. Risked mean resource estimates for ANWR nearly match those expected for the entire Atlantic OCS Region (0.68 billion barrels).

Both the Navarin Basin (upper Bering Sea) and the Beaufort Sea, being in offshore Arctic waters, are located in difficult operating environments which must contend with sea ice, severe weather conditions, extremely low temperatures and long winter periods of near total darkness. Offshore exploration and development is extremely expensive under these conditions, and the distances that oil would have to be transported will likely require very high per-barrel prices (>$32 per barrel) and giant fields of 250 to 500 million barrels to warrant development. The Department of the Interior determined that the most likely minimum economic field size in ANWR would be 440 million barrels at $33/bbl (1 984$). This appears to be somewhat larger than might be expected when compared to more expensive offshore development. However, the determination of economic field size depends on many assumed economic factors, in addition to location onshore or offshore, which cannot be determined in frontier regions until a field is delineated.

ANWR Petroleum Resources in Perspective

The economics of any exploration and development of oil and gas resources that may occur in the ANWR 1002 area are closely tied to the existence of the Trans-Alaska Pipeline System (TAPS) which originates at Prudhoe Bay. TAPS has the capacity to transport about 2.2 mmbd of oil from the North Slope to its marine terminal at Valdez on the southern coast of Alaska. Prudhoe Bay throughput has ranged between 1.5 and 1.8 mmbd since the field came on line at maximum production. However, with Prudhoe Bay production soon to be declining and increases in oil reserves *through* field extension not keeping pace with drawdown, there will likely be ample excess pipeline capacity to accommodate as much as 1 mmbd of oil from ANWR by the time that maximum production could possibly occur,

While the cost of a feeder pipeline from ANWR to Pump Station No. 1 at Prudhoe Bay would be substantial, the existence of TAPS and its potential excess future capacity boosts the economic outlook for ANWR. However, the potential resource base is not equally distributed throughout the 1.5 million acres of the ANWR 1002 area. Over three-quarters of the in-place oil is expected to occur in the extreme western portions and the extreme eastern portions, with the central area having the lowest potential. Resources that may be discovered in the eastern blocks of ANWR would require almost double the length of feeder pipeline required for resources occurring in the western block.

Although natural gas was not considered by the Department of the Interior in determining the estimates of economically recoverable resources, its potential as a future resource cannot be wholly ignored. Prudhoe Bay gas is currently reinfected into the producing formations to maintain pressure and conserve the resource. Production in ANWR would follow a similar course. But the uncertainty of the U.S. energy future suggests that Alaskan natural gas may evolve into a future economic resource of considerable value. Although no credible analysis could be devised to prove this point, sufficient uncertainties about energy pricing and hydrocarbon supplies exist so that the possibility of future economic viability should not be discounted.

Current prices in the depressed world oil market logically raise questions about the feasibility of exploring for petroleum in the high-cost Arctic Tundra. But today's oil prices are not a reasonable measure of economic feasibility for investment in exploration and development that may require decades to complete. From the time the Secretary of the Interior forwarded the ANWR report to Congress (in April 1987), at least 3 to 5 years may be necessary for the enactment of leasing legislation. Unless Congress approved administrative shortcuts, at least an additional 3 to 4 years would be needed to promulgate regulations, prepare an environmental impact statement, and process leases.

If exploration and development were to begin between 1992 and 1995–6 to 9 years after the legislative process begins–it would not be until

2002 to 2005 that production would likely begin in ANWR assuming 10 years from the beginning of exploration to development and first production. Recent experience with erratic changes in energy prices and the course of the national economy suggests that it is foolhardy to speculate on economic conditions 15 to 18 years in the future.

Exploration costs in the coastal plain of ANWR would be considerably cheaper than any comparable offshore exploration program in the OCS with the highest prospects for the discovery of very large oilfields. The cost of drilling an exploratory well onshore in the Arctic is generally estimated to be in the range of about $10 to $25 million. An exploratory well in the frontier Navarin Basin in the Bering Sea is estimated to cost about $55 million. Exploratory wells in the Beaufort Sea are estimated to cost on the order of $30 million for ice-free conditions and up to about $50 million for ice conditions. The Mukluk exploration well on an artificial island in the Beaufort northwest of Prudhoe Bay, when abandoned as a dry hole, cost an estimated $140 million, although part of the high cost has been said to be due to the need to maintain a very fast pace.

The Department of the Interior foresees the **need for about** 25 exploratory wells for the ANWR 1002 area under its full leasing scenario and 16 under a scaled-down alternative centered on the best drilling prospects. If drilling costs can be held to the low side of the range for onshore Arctic drilling, total cost for exploratory drilling (not including general support facilities) on ANWR could range between $160 million and $250 million. Compared with the costs for drilling exploratory wells at single locations in the best offshore prospects of Alaska ($30 to $50 million and up, for most situations), ANWR may offer the cheapest and perhaps the most direct way to determine whether another giant oilfield lies below lands under the jurisdiction of the United States. However, before ANWR is leased and explored, formidable environmental issues must be resolved.

Environmental Issues

Background.–A major battle is expected between development-oriented and environmental groups over the issue of whether or not to proceed with oil and gas exploration and eventual development in ANWR. The oil industry, as well as many elected officials from the State of Alaska, key personnel from the U.S. Department of the Interior, and several native Alaskan organizations, view the coastal plain of the ANWR as having the most promising oil and gas potential of any region in the country. Environmental groups contend that the wilderness value and wildlife habitat the area provides are unparalleled and that development would threaten the animals (particularly the Porcupine caribou herd) that spend all or part of their time in the Refuge.

The Fish and Wildlife Service (FWS) was designated by the Department of the Interior to conduct the 1002 study on the fish and wildlife resources and petroleum potential of the ANWR coastal plain. The study is essentially a response to the question of whether or not oil and gas development can coexist with wilderness and wildlife in the ANWR area, or, alternatively, a determination of the relative importance with respect to national needs of oil development and preservation of the refuge. FWS found that "long-term losses of fish and wildlife resources, subsistence uses, and wilderness values would be inevitable consequences of a long-term commitment to oil and gas development, production, and transportation,"[57] and also that leasing of the 1002 area "could contribute billions of barrels of additional oil reserves toward the national need for domestic sources."[58] Based on its findings, FWS has recommended that Congress authorize the Secretary of the Interior to lease the entire 1002 area for oil and gas exploration and development.[59]

Key Environmental and Socioeconomic Concerns.–The entire ANWR, including the coastal plain, is in fact if not in name a wilderness area, that is, an area essentially untouched by development. Although the area considered for leasing (1.5 million acres) is only a fraction of the refuge, it includes virtually the entire coastal plain of northeast Alaska.

[57] U.S. Department of the Interior, *Arctic National Wildlife Refuge, Alaska, Coastal Plain Resource Assessment* (Washington, DC: U.S. Department of the Interior, November 1986), p. 6.
[58] Ibid., p. 8.
[59] Ibid., p. 1.

Environmentalists argue that oil development in ANWR would not only diminish the wilderness nature of the coastal plain but would eventually make it easier to explore adjacent offshore areas and the remaining State land between Prudhoe Bay and the ANWR for oil and gas potential. All of these developments would have additional negative environmental impacts on the Arctic coastal plain. A bill to designate the coastal plain of the ANWR as wilderness has already been submitted to Congress by Congressman Morris Udall and was recently reintroduced in the 10Oth Congress.

A key concern is the impact that development will have on the approximately 180,000 caribou of the porcupine herd that use the refuge. One part of the coastal plain is particularly important as a calving area for the Porcupine herd. The coastal plain also offers relief to the herd from insects. Before actual exploration and development occurs, it is difficult to say what the impact of oil and gas development on the herd will be. Those in favor of development point out that the Central Arctic caribou herd, whose range includes the Prudhoe Bay area, has actually increased in size since development began. The Porcupine herd, however, spends less time on the coastal plain than the Central Arctic herd, and the question of whether the Porcupine herd can be acclimated to development like the Central Arctic herd is open to debate.

The U.S. Fish and Wildlife Service has concluded that it is reasonable to assume that development can proceed with minimal adverse impacts on the herd. In the draft 1002 report, FWS proposed that the most sensitive area (an area of approximately 242,000 acres) be leased last—after determining how the caribou respond and what mitigation measures would be most effective. The final version of the draft, however, recommended that the entire coastal plain be opened to leasing. Most environmental groups are not convinced that oil and gas development is compatible with the health of the caribou herd. Also, although the focus of attention has been on caribou, other wildlife in the area could be affected by development.

Of particular concern to some environmentalists is construction of a haul road and pipeline connecting Prudhoe Bay with the ANWR. The presence of either would disqualify the coastal plain for wilderness status. in addition, the pipeline could be a barrier to caribou migration, and some worry that it could eventually be extended to the MacKenzie Delta area in the Canadian Arctic,[60] thereby eliminating more wilderness.

Socioeconomic consequences for the native Inuit population (especially in the village of Kaktovik) are also expected to be significant. The Inuit have subsurface rights to a considerable amount of acreage and can be expected to profit from development. Two native corporations, the Kaktovik Inupiat Corp. and the Arctic Slope Regional Corp., are involved, and have generally been supportive of controlled development. Other native groups–particularly those dependent on the Porcupine herd but unlikely to share in the direct economic benefits of oil development—have opposed development.

Development would bring changes in the traditional subsistence lifestyle of most natives, as more Inuit would have the opportunity to work for cash in the oilfields. Introduction to 20th century culture has proven to be a two-edged sword to Inuit in other parts of the Arctic, however. Modern conveniences benefit Inuit just as they benefit others, but development is also at least partly responsible for the increase of such social problems as alcoholism. While happy to have additional income, many Inuit regret the decline of traditional culture.

The Effects of the Natural Gas Surplus

Since the early 1980s, natural gas production capacity has been in substantial surplus, primarily because of declining demand in the electric utility and heavy industry sectors but also because of a surge in gas deliverability. This surplus has been remarkably persistent, and it has created a situation in which producers in some parts of the country cannot be assured of markets for new gas production. The disincentive for gas drilling

[60] Although there appears to be little reason for such an extension, because the TAPS pipeline should have adequate excess capacity in the appropriate timeframe to handle any ANWR production.

created by poor markets has affected overall drilling patterns of the past few years. The overall economic effect on oil drilling is mixed: on the one hand, because many oil wells produce gas and because some drilling seeks hydrocarbons rather than oil or gas in particular, the slack gas market can hurt oil drilling; on the other hand, the reduction in total drilling caused by the poor gas market was one of the causes of the large reduction in drilling costs between 1981 and the present, and this reduction in turn improved the economics of oil drilling. Most probably, an end to the surplus and reestablishment of firm gas markets would aid in a general E&D recovery because drilling costs are unlikely to rebound without a very large increase in drilling—an unlikely event if oil prices remain low. However, the two determinants of the date of an end to the surplus—gas supply and gas consumption—are quite uncertain. Consumption is greatly affected by fuel switching to oil, which in turn is dependent on uncertain oil prices and the ability of gas pipelines to compete with oil on price. Future gas supply is the subject of a substantial divergence of opinion, even more so than is future oil supply, although most forecasts agree that U.S. domestic production will decline in the 1990s and will require added imports, especially from Canada.